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

COMMERCIAL WARM AIR FURNACES

December 15, 2015

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CHAPTER 1. INTRODUCTION

TABLE OF CONTENTS

1.1 PURPOSE OF THE DOCUMENT 1-1
1.2 SUMMARY OF NATIONAL BENEFITS 1-1
1.3 OVERVIEW OF ENERGY CONSERVATION STANDARDS FOR COMMERCIAL WARM AIR FURNACES 1-5
1.4 PROCESS FOR SETTING ENERGY CONSERVATION STANDARDS 1-6
1.5 STRUCTURE OF THE DOCUMENT 1-8

LIST OF TABLES

Table 1.2.1 Summary of National Economic Benefits and Costs of Amended Energy Conservation Standards for Commercial Warm Air Furnaces* 1-2
Table 1.2.2 Annualized Benefits and Costs of Amended Standards for Commercial Warm Air Furnaces* 1-4
Table 1.3.1 Federal Energy Conservation Standards for Commercial Warm Air Furnaces 1-6

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 direct final rule (DFR) for commercial warm air furnaces (herein referred to as CWAF). This DFR TSD reports on the activities and analyses conducted in support of the DFR.

1.2 SUMMARY OF NATIONAL BENEFITS

DOE's analyses indicate that the adopted energy conservation standards for CWAFs would save a significant amount of energy. Relative to the case without amended standards (referred to as the "no-new-standards case"), the lifetime energy savings for CWAFs purchased in 2023–2048 amount to 0.23 quads. This represents a savings of 0.8 percent relative to the energy use of these products in the case without amended standards.

The cumulative NPV of total consumer costs and savings of the standards for CWAFs ranges from $0.3 billion (at a 7-percent discount rate) to $1.0 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for CWAFs purchased in 2023-2048.

In addition, the CWAF equipment standards that are being adopted in this direct final rule are projected to yield significant environmental benefits as a result of the improvement in the conservation of energy. Specifically, these standards are projected to result in cumulative GHG reductions (over the same period as for energy savings) of 12.4 Mt of CO_2, 0.40 thousand tons of SO_2, 41.2 tons of NO_X, 146 thousand tons of CH_4, 0.03 thousand tons of N_2O, and 0.001 tons of mercury. The cumulative reduction in CO_2 emissions through 2030 amounts to 0.9 Mt, which is equivalent to the emissions resulting from the annual electricity use of about 79,000 homes.

The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 developed by the Federal interagency Working Group. 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) ranges from $71.4 million to $1,078 million, with a value of $353 million 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 $36.1 million at a 7-percent discount rate, and $110 million at a 3-percent discount rate.

Table 1.2.1 summarizes the national economic benefits and costs expected to result from the adopted CWAF standards.

Table 1.2.1 Summary of National Economic Benefits and Costs of Amended Energy Conservation Standards for Commercial Warm Air Furnaces*

Category	Present Value *Billion 2014$*	Discount Rate
Benefits		
Operating Cost Savings	0.4	7%
	1.0	3%
CO_2 Reduction Value ($12.2/t case)**	0.07	5%
CO_2 Reduction Value ($40.0/t case)**	0.35	3%
CO_2 Reduction Value ($62.3/t case)**	0.57	2.5%
CO_2 Reduction Value ($117/t case)**	1.08	3%
NO_X Reduction Value†	0.04	7%
	0.11	3%
Total Benefits††	0.76	7%
	1.5	3%
Costs		
Consumer Incremental Installed Costs	0.03	7%
	0.06	3%
Net Benefits		
Including CO_2 and NO_X Reduction Monetized Value††	0.72	7%
	1.4	3%

* This table presents the costs and benefits associated with CWAFs shipped in 2023−2048. These results include benefits to commercial consumers which accrue after 2048 from the products purchased in 2023−2048. 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.) 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 average SCC with 3-percent discount rate ($40.0/t case).

The benefits and costs of the adopted standards, for CWAFs sold in 2023−2048, can also be expressed in terms of annualized values. The monetary values for the total annualized net benefits are the sum of (1) the national economic value of the benefits in reduced operating costs, minus (2) the increases in product purchase prices and installation costs, plus (3) the value of the

benefits of CO_2 and NO_X emission reductions, all annualized.[1]

Estimates of annualized benefits and costs of the adopted standards are shown in Table 1.2.2. 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 standards in this rule is $4.31 million per year in increased equipment costs, while the estimated annual benefits are $49 million in reduced equipment operating costs, $24 million in CO_2 reductions, and $5.49 million in reduced NO_X emissions. In this case, the net benefit amounts to $75 million per year. Using a 3-percent discount rate for all benefits and costs and the SCC series has a value of $40.0/t in 2015, the estimated cost of the standards is $4.38 million per year in increased equipment costs, while the estimated annual benefits are $71 million in reduced operating costs, $24 million in CO_2 reductions, and $8.76 million in reduced NO_X emissions. In this case, the net benefit amounts to $99 million per year.

[1] 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., 2020 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 CO_2 reductions, for which DOE used case-specific discount rates, as shown in Table 1.2.1. 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.

Table 1.2.2 Annualized Benefits and Costs of Amended Standards for Commercial Warm Air Furnaces*

	Discount Rate	Primary Estimate	Low Estimate	High Estimate
		Million 2014$/year		
Benefits				
Operating Cost Savings	7%	49	48	54
	3%	71	70	81
CO_2 Reduction Value ($12.2/t case)**	5%	6.99	7.08	7.37
CO_2 Reduction Value ($40.0/t case)**	3%	24	25	26
CO_2 Reduction Value ($62.3/t case)**	2.50%	36	36	38
CO_2 Reduction Value ($117/t case)**	3%	74	75	79
NO_X Reduction Value†	7%	5.49	5.57	5.73
	3%	8.76	8.88	9.26
Total Benefits††	7% plus CO_2 range	62 to 129	61 to 129	67 to 139
	7%	79	78	86
	3% plus CO_2 range	87 to 154	86 to 154	97 to 168
	3%	104	103	116
Costs				
Consumer Incremental Product Costs	7%	4.31	5.04	3.92
	3%	4.38	5.22	3.94
Net Benefits				
Total††	7% plus CO_2 range	57 to 124	56 to 124	63 to 135
	7%	75	73.1	81.8
	3% plus CO_2 range	83 to 150	80 to 148	93 to 164
	3%	100	98	112

* This table presents the annualized costs and benefits associated with CWAFs shipped in 2023-2048. These results include benefits to commercial consumers which accrue after 2048 from the CWAFs purchased from 2023-2048. 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 appendix 10C.

** 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 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 ENERGY CONSERVATION STANDARDS FOR COMMERCIAL WARM AIR FURNACES

Title III of the Energy Policy and Conservation Act of 1975 (EPCA), Pub. L. 94-163, as amended, sets forth a variety of provisions concerning energy efficiency.[2] Part C[3] of Title III created the Energy Conservation Program for Certain Industrial Equipment, a program covering CWAF, the subjects of this rulemaking. (42 U.S.C. 6311-6317) In general, this program addresses the energy efficiency of certain types of commercial and industrial equipment. Relevant provisions of EPCA specifically include definitions (42 U.S.C. 6311), energy conservation standards (42 U.S.C. 6313), test procedures (42 U.S.C. 6314), labeling provisions (42 U.S.C. 6315), and the authority to require information and reports from manufacturers (42 U.S.C. 6316).

EPCA contains mandatory energy conservation standards for commercial heating, air-conditioning, and water-heating equipment, including the CWAF that are the subject of this rulemaking. (42 U.S.C. 6313(a)) The initial Federal energy conservation standards for CWAF were added to EPCA by the Energy Policy Act of 1992 (EPACT 1992), Public Law 102–486. (42 U.S.C. 6313(a)(4)) These types of covered equipment have a rated capacity (rated maximum input) greater than or equal to 225,000 Btu/h, can be gas-fired or oil-fired, and are designed to heat commercial buildings. The current standards are set forth in Table 1.3.1. The efficiency standards for CWAF established by EPACT 1992 correspond to the levels contained in American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 90.1-2004, Energy Standard for Buildings Except Low-Rise Residential Buildings, which originated as addendum "d" to ASHRAE Standard 90.1-2001.

[2] All references to EPCA in this document refer to the statute as amended through the American Energy Manufacturing Technical Corrections Act of 2012, Pub. L. 112-210 (enacted Dec. 18, 2012).
[3] This Part was subsequently redesignated as Part A-1 for editorial reasons after Part C of Title III of EPCA was repealed by Pub. L. 109-58.

Table 1.3.1 Federal Energy Conservation Standards for Commercial Warm Air Furnaces

Equipment Class	Thermal Efficiency
Gas-Fired, ≥ 225,000 Btu/hr Input Capacity	80%
Oil-Fired, ≥ 225,000 Btu/hr Input Capacity	81%

1.4 PROCESS FOR SETTING ENERGY CONSERVATION STANDARDS

Under EPCA, DOE is obligated to review its energy conservation standards for certain commercial and industrial equipment[4] (*i.e.*, "ASHRAE equipment") whenever ASHRAE updates the efficiency levels in ASHRAE Standard 90.1.DOE must either adopt the levels contained in ASHRAE Standard 90.1 or adopt levels more stringent than the ASHRAE levels if there is clear and convincing evidence in support of doing so.(42 U.S.C. 6313(a)(6)(A))Such review is to be conducted in accordance with the procedures established for ASHRAE equipment under 42 U.S.C. 6313(a)(6).

In addition, pursuant to amendments to EPCA made by the Energy Independence and Security Act of 2007 (EISA 2007), under 42 U.S.C. 6313(a)(6)(C), the agency must periodically review its already-established energy conservation standards for ASHRAE equipment, including CWAF. This provision was further amended by the American Energy Manufacturing Technical Corrections Act (AEMTCA), Public Law 112–210 (Dec. 18, 2012), to clarify that DOE's periodic review of ASHRAE equipment must occur "[e]very six years." (42 U.S.C. 6313(a)(6)(C)(vi)) AEMTCA also added a requirement that DOE must conduct an expedited rulemaking to consider amended energy conservation standards for any covered equipment of those types for which more than 6 years has elapsed since the issuance of the most recent final rule establishing or amending a standard for the product as of the date of AEMTCA's enactment (*i.e.,* December 18, 2012). (42 U.S.C. 6313(a)(6)(C)(i) and (vi)) In order to meet the new requirements added by AEMTCA, DOE has begun to review its existing energy conservation standards for those equipment types listed in 42 U.S.C. 6313(a) for which at least six years have elapsed since issuance of the most recent final rule, including the CWAFs that are the subject of this rulemaking.

EPCA, as amended by AEMTCA, prescribes specific statutory criteria for DOE to consider when setting standards for CWAF. (42 U.S.C. 6313(a)(6)(A)–(C))Any amended standard for covered equipment more stringent than the level contained in ASHRAE Standard 90.1 must be designed to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified.(42 U.S.C. 6313(a)(6)(A)(ii)(II))Furthermore, DOE may not adopt any standard that would not result in the significant additional conservation of energy. *Id.* DOE, in deciding whether a standard is economically justified, must determine,

[4] These equipment types include small, large, and very large commercial package air-conditioning and heating equipment, packaged terminal air conditioners and heat pumps, warm air furnaces, packaged boilers, storage water heaters, instantaneous water heaters, or unfired hot water storage tanks.

after receiving comments on the standard, whether the benefits of the standard exceed its burdens by considering, to the maximum extent practicable, the following seven factors:

(1) the economic impact of the standard on the manufacturers and consumers of the products subject to the standard;

(2) the savings in operating costs throughout the estimated average life of the products in the type (or class) compared to any increases in the price, initial charges, or maintenance expense for the products that are likely to result from the imposition of the standard;

(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. (42 U.S.C. 6313(a)(6)(B)(ii))

Other applicable statutory requirements are set forth in 42 U.S.C. 6295(p)(4), 42 U.S.C. 6296(a),(b),(d), 42 U.S.C. 6297(a), 42 U.S.C. 6298-6306.

DOE considers the participation of interested parties a very important part of the process for setting energy conservation standards. Through formal public notifications (*i.e.*, *Federal Register* notices), DOE encourages the participation of all interested parties during the comment period in each stage of the rulemaking. Throughout the entire duration of the rulemaking process, 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 6313(a)(6)(B)(i)) Any new or amended standard must be designed to achieve significant additional conservation of energy and be technologically feasible and economically justified. (42 U.S.C. 6313(a)(6)(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. 6313(a)(6)(B)(ii))

On February 4, 2015, DOE published a notice of proposed rulemaking (February 2015 NOPR) in the *Federal Register* proposing amended energy conservation standards for CWAF. 80 FR 6181. The February 2015 NOPR was published pursuant to EPCA's requirements for DOE to consider amended energy conservation standards for certain types of commercial equipment covered by ASHRAE Standard 90.1, including CWAF. DOE solicited public comment on the February 2015 NOPR, and received feedback from multiple stakeholders,

including manufacturers of CWAF, industry trade groups, energy efficiency advocates, and utilities.

On April 1, 2015, DOE published a notice of intent to establish a working group to negotiate either a NOPR or final rule for energy conservation standards for both commercial package air conditioners (CUAC) and CWAF. 80 FR 17363. This working group was established under the Appliance Standards and Rulemaking Federal Advisory Committee (ASRAC) in accordance with the Federal Advisory Committee Act and the Negotiated Rulemaking Act. Throughout the working group negotiations, DOE received additional feedback from stakeholders regarding amended energy conservation standards for CWAF. DOE used this feedback and the feedback received in response to the February 2015 NOPR to conduct the analyses supporting this DFR. Each of these analyses is explained in detail in this TSD. A list of the analyses and corresponding TSD chapter numbers is presented in the next section. Chapter 2 of this TSD presents a summary of each analysis conducted

1.5 STRUCTURE OF THE DOCUMENT

This TSD outlines the analytical approaches used in this rulemaking. The TSD consists of 17 chapters and numerous supporting appendices.

Chapter 1 Introduction: Provides an overview of the appliance and equipment standards program and how it applies to CWAF, and outlines the structure of the document.

Chapter 2 Analytical Framework: Describes the rulemaking process step by step and summarizes the major components of DOE's analyses.

Chapter 3 Market and Technology Assessment: Characterizes the CWAF equipment market and describes the technologies available for increasing equipment efficiency.

Chapter 4 Screening Analysis: 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 increased efficiency and increased manufacturer production cost/selling price.

Chapter 6 Markups Analysis: Discusses the methods used for establishing markups for converting manufacturer prices to customer equipment prices.

Chapter 7 Energy Use Analysis: Discusses the process used for generating energy-use estimates of CWAF for a variety of equipment classes, climate locations, and efficiency levels.

Chapter 8 Life-Cycle Cost and Payback Period Analyses: Discusses the economic

effects of standards on individual customers and users of the equipment and compares the LCC and PBP of equipment with and without higher efficiency standards.

Chapter 9 Shipments Analysis: Discusses the methods used for projecting shipments with and without higher efficiency standards.

Chapter 10 National Impact Analysis: Discusses the methods used for projecting national energy savings and national economic impacts based on annual product shipments and estimates of future equipment efficiency distributions in the absence and presence of higher efficiency standards.

Chapter 11 Consumer Subgroup Analysis: Discusses the effects of standards on a subgroup of commercial warm air furnace customers and compares the LCC and PBP of equipment with and without higher efficiency standards for these customers.

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 (NOx), 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 Equipment Price Markups

Appendix 7A Building Variables

Appendix 7B Determination of Commercial Warm Air Furnace Energy Use in the LCC Analysis

Appendix 7C Mapping of Weather Station Data to CBECS and RECS Buildings

Appendix 7D Reduced Set of Commercial Warm Air Furnace Models and

	Characteristics
Appendix 8A	User Instructions for Life-Cycle Cost Analysis Spreadsheet for Commercial Warm Air Furnaces
Appendix 8B	Uncertainty and Variability in the LCC Analysis for Commercial Warm Air Furnaces
Appendix 8C	Energy Price Calculations for Commercial Warm Air Furnaces
Appendix 8D	Installation Cost Determination for Commercial Warm Air Furnaces
Appendix 8E	Maintenance and Repair Cost Determination for Commercial Warm Air Furnaces
Appendix 8F	Commercial Warm Air Furnace Lifetime Determination
Appendix 8G	Distributions Used for Discount Rates
Appendix 8H	Life-Cycle Cost Analysis Using Alternative Economic Growth Scenarios for Commercial Warm Air Furnaces
Appendix 9A	Relative Price Elasticity of Demand for Appliances
Appendix 10A	User Instructions for National Impact Analyses Spreadsheet Model
Appendix 10B	Full-Fuel-Cycle Analysis
Appendix 10C	National Net Present Value of Commercial Warm Air Furnaces Using Alternative Equipment Price Forecasts
Appendix 10D	National Impact Analysis Using Alternative Economic Growth Scenarios for Commercial Warm Air Furnaces
Appendix 12A	Manufacturer Impact Analysis Interview Guide
Appendix 12B	Government Regulatory Impact Model (GRIM) Overview
Appendix 13A	Emissions Analysis Methodology
Appendix 14A	Social Cost Of Carbon for Regulatory Impact Analysis under Executive Order 12866
Appendix 14B	Technical Update of Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866
Appendix 15A	Utility Impact Analysis Methodology
Appendix 17A	Regulatory Impact Analysis: Supporting Materials

CHAPTER 2. ANALYTICAL FRAMEWORK

TABLE OF CONTENTS

2.1. INTRODUCTION 2-1
2.2. BACKGROUND 2-4
2.3. MARKET AND TECHNOLOGY ASSESSMENT 2-5
2.3.1. Market Assessment 2-5
2.3.2. Technology Assessment 2-5
2.4. SCREENING ANALYSIS 2-5
2.5. ENGINEERING ANALYSIS 2-6
2.6. MARKUPS ANALYSIS 2-6
2.7. ENERGY USE ANALYSIS 2-7
2.8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSIS 2-7
2.9. SHIPMENTS ANALYSIS 2-8
2.10. NATIONAL IMPACT ANALYSIS 2-9
2.10.1. National Energy Savings Analysis 2-9
2.10.2. Net Present Value Analysis 2-9
2.11. CONSUMER SUBGROUP ANALYSIS 2-10
2.12. MANUFACTURER IMPACT ANALYSIS 2-10
2.13. EMISSIONS IMPACT ANALYSIS 2-10
2.14. MONETIZATION OF EMISSION REDUCTION BENEFITS 2-11
2.15. UTILITY IMPACT ANALYSIS 2-12
2.16. EMPLOYMENT IMPACT ANALYSIS 2-13
2.17. REGULATORY IMPACT ANALYSIS 2-13

LIST OF FIGURES

Figure 2.1.1 Flow Diagram of Analyses for the Rulemaking Process 2-2

CHAPTER 2. ANALYTICAL FRAMEWORK

2.1 INTRODUCTION

The Energy Policy and Conservation Act of 1975 (EPCA) requires the U.S. Department of Energy (DOE) to set forth energy conservation standards that are technologically feasible and economically justified and would result in significant additional energy conservation. (42 U.S.C. 6313(a)(6)(A)(ii)(II)) This chapter provides a description of the general analytical framework that DOE uses in developing such standards, in particular, standards for Commercial Warm Air Furnaces (CWAF). The analytical framework is a description of the methodology, the 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 stakeholders or persons 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.

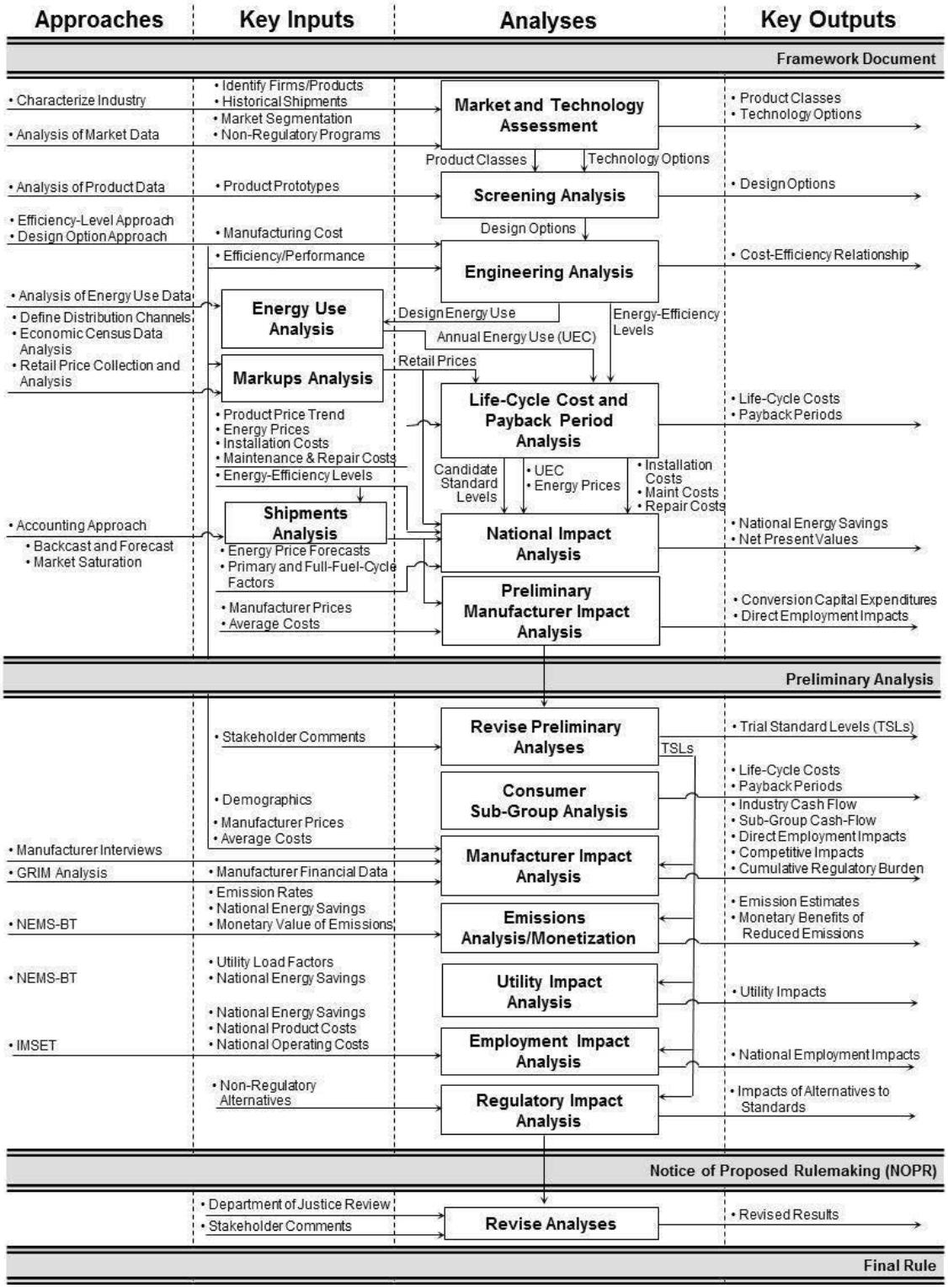

Figure 2.1.1 Flow Diagram of Analyses for the Rulemaking Process[a]

[a] Note: This rulemaking bypassed the preliminary analysis stage and went straight to the NOPR analysis stage.

In developing the direct final rule (DFR), 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 February 2015 NOPR. In this TSD, DOE presents results of the following analyses that were performed for the DFR:

- A market and technology assessment to characterize the relevant product markets and existing technology options, including prototype designs.

- A screening analysis to review each technology option to decide whether it is technologically feasible and to determine if the technology option is practicable to manufacture, install, and service, would adversely affect equipment utility or availability, or would have adverse impacts on health and safety.

- An engineering analysis to develop cost-efficiency relationships, which indicate the manufacturer's cost of achieving higher efficiency levels.

- A markups analysis to develop distribution channel markups that relate the changes in manufacturing cost of increased equipment efficiency to the cost to the customer of higher efficiency equipment.

- An analysis of the annual energy consumption of CWAF as a function of efficiency.

- A life-cycle cost (LCC) and payback period (PBP) analyses to calculate, at the customer level, the discounted savings in operating costs (minus maintenance and repair costs) throughout the estimated average lifetime of the covered equipment, compared to any increase in purchase and installation cost likely to result directly from imposition of a given standard.

- A shipments analysis to forecast shipments of CWAF, which is 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 aggregate impacts at the national level of potential energy conservation standards for the considered equipment, as measured by the NPV of total consumer economic impacts and the national energy savings (NES).

- An LCC subgroup analysis to evaluate variations in customer characteristics that might cause a standard to disproportionately affect particular customer 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.

- 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 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.

- 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

As chapter 1 of this TSD describes, the initial Federal energy conservation standards for CWAF were added to EPCA by the Energy Policy Act of 1992 (EPACT 1992), Public Law 102–486. (42 U.S.C. 6313(a)(4)) The efficiency standards for CWAF established by EPACT 1992 correspond to the levels contained in ASHRAE Standard 90.1-2004, which originated as addendum "d" to ASHRAE Standard 90.1-2001.

Section 5(b) of the American Energy Manufacturing Technical Corrections Act (AEMTCA), Public Law 112–210 (Dec. 18, 2012), amended EPCA to include a requirement for DOE to consider amending the standards for certain types of commercial and industrial equipment, including CWAF, every six years, as well as a mandate that DOE must conduct an expedited rulemaking to consider amended energy conservation standards for any covered equipment of those types for which more than 6 years has elapsed since the issuance of the most recent final rule establishing or amending a standard for the product. Because at the time AEMTCA was enacted the energy conservation standards for CWAF had not been reviewed within the previous 6 years, an expedited rulemaking for CWAF was initiated.

In accordance with EPCA's requirements, on May 2, 2013, DOE published a request for information (RFI) in the *Federal Register* as a preliminary step pursuant to EPCA's requirements for DOE to consider amended energy conservation standards for CWAF. 76 FR 25622. On February 4, 2015, DOE subsequently published a notice of proposed rulemaking (February 2015 NOPR) in the *Federal Register* proposing to amend the Federal energy conservation standards for CWAF. 80 FR 6181. On April 1, 2015, DOE published a notice of intent to establish a working group to negotiate potential energy conservation standards for both commercial package air conditioners (CUAC) and CWAF. 80 FR 17363. In the subsequent working group negotiations, stakeholders agreed upon the amended CWAF standard levels promulgated in this DFR.

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

2.3 MARKET AND TECHNOLOGY ASSESSMENT

The market and technology assessment characterizes the relevant product markets and existing technology options, including prototype designs, for the CWAF analyzed in this rule.

2.3.1 Market Assessment

When initiating a standards rulemaking, DOE gathers information on the present and past industry structure and market characteristics for the equipment concerned. This activity assesses the industry and equipment both quantitatively and qualitatively based on publicly available information and encompasses the following: (1) manufacturer market share and characteristics, (2) existing regulatory and non-regulatory equipment efficiency improvement initiatives, and (3) trends in equipment characteristics and retail markets. This information serves as resource material throughout the rulemaking.

DOE reviewed existing literature and interviewed manufacturers to get an overall picture of the industry serving the United States CWAF market. Industry publications and trade journals, government agencies, trade organizations, manufacturers' websites, and equipment literature provided the bulk of the information, including: (1) manufacturers and their approximate market shares, (2) equipment characteristics, and (3) industry trends. Supporting documentation on the market assessment is provided in chapter 3 of this TSD.

2.3.2 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 CWAF through consultation with manufacturers of components and systems and from trade publications and technical papers. Since many options for improving CWAF efficiency are available in existing units, product literature and direct examination of equipment provided additional information. The technologies examined in the technology assessment are described in detail in chapter 3 of this TSD.

2.4 SCREENING ANALYSIS

The screening analysis (chapter 4 of the TSD) examines various technologies as to whether they: (1) are technologically feasible; (2) are practicable to manufacture, install, and service; (3) have an adverse impact on equipment utility or availability; and (4) have adverse impacts on health and safety. As described in section 2.3.2, develops an initial list of technology options that are believed to be technologically feasible and offer energy efficiency improvements. In consultation with interested parties, DOE then reviews the list of technology options to determine if these options are practicable to manufacture, install, and service, would not adversely affect product utility or availability, and would not have adverse impacts on health and safety. Technology options which do not meet all of these criteria are eliminated from

further consideration in the rulemaking analyses. DOE passes on any technology options that were not eliminated at this step to the engineering analysis.

2.5 ENGINEERING ANALYSIS

The engineering analysis (chapter 5 of the TSD) establishes the relationship between the manufacturing production cost (MPC) and equipment efficiency for CWAF. This relationship serves as the basis for cost/benefit calculations in terms of individual customers, manufacturers, and the nation. Chapter 5 of this TSD discusses the representative baseline units of each equipment class, the incrementally higher efficiency levels, the methodology DOE used to develop the MPCs, manufacturer markups, and cost-efficiency curves.

In the engineering analysis, DOE evaluates a range of equipment efficiency levels and their associated MPCs. The purpose of the analysis is to estimate the incremental MPCs for equipment that would result from increasing efficiency levels above the baseline efficiency level in each equipment class. The engineering analysis considers technologies that were not eliminated in the screening analysis, although certain technologies were not analyzed due to negligible incremental efficiency improvements or the inability of the existing DOE test procedures to measure any reduction in energy use. DOE considers the remaining technologies 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 equipment being analyzed.

DOE conducted the engineering analysis for CWAF using the reverse-engineering approach for analysis of various thermal efficiency levels. More specifically, DOE identified the efficiency levels for analysis and then used the reverse-engineering approach to determine the MPCs at those levels. This approach involved physically disassembling commercially available equipment, consulting with outside experts, reviewing publicly available cost and performance information, and modeling equipment cost. The efficiency levels that DOE considered in the engineering analysis are attainable using technologies currently available on the market. Chapter 5 of this TSD describes the methodology and results of the engineering analysis used to derive the cost-efficiency relationships.

2.6 MARKUPS ANALYSIS

DOE performed a markups analysis to convert the manufacturer costs estimated in the engineering analysis to consumer prices, which then were used in the LCC and PBP and manufacturer impact analyses. DOE calculated markups for baseline equipment (baseline markups) and for more efficient equipment (incremental markups). The 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 products are distributed from the manufacturer to the commercial consumer. After establishing appropriate distribution channels, DOE relied on economic data from the U.S. Census Bureau and other sources to determine how prices are marked up as the equipment pass from the manufacturer to the commercial consumer. Chapter 6 of this TSD provides details on DOE's development of markups for CWAF.

2.7 ENERGY USE ANALYSIS

The energy use analysis assesses the energy savings potential from adopting higher efficiency standards for CWAF equipment. 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 CWAF at specified energy efficiency levels for a representative set of commercial and residential users of this equipment as defined by building type and location. The energy consumption estimates for CWAF include the heating energy use by the equipment for space heating, as well as the auxiliary electricity consumption, such as the blower, the draft inducer, and the ignition device.

DOE used the Energy Information Administration's (EIA) 2003 Commercial Building Energy Consumption Survey (CBECS 2003)[b] and 2009 Residential Energy Consumption Survey (RECS 2009)[c] energy data and weather data from NOAA to estimate weather-normalized energy use. The CBECS 2003 data provide information on the vintage of the building, building square footage, fuels used, heating energy use, and other relevant data. Criteria were developed to help size these CWAF using several variables, including building square footage. For CWAF used in multi-family housing, DOE used the RECS 2009 sample.

As part of the energy use analysis, DOE made certain assessments about building design and building operating characteristics that impact the energy use results for the considered equipment classes. These assessments, along with the methods used in the energy use analysis, are documented in chapter 7 of the TSD.

2.8 LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSIS

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

- LCC 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 (product

[b] Energy Information Administration (EIA), 2003 Commercial Building Energy Consumption Survey (Available at: http://www.eia.gov/consumption/commercial/) (Last accessed April 10, 2013). Note: CBECS 2012 is currently in development but was not available in time for this rulemaking. The full CBECS 2012 dataset is expected to be available in April 2016.

[c] EIA, 2009 Residential Energy Consumption Survey (Available at: http://www.eia.gov/consumption/residential/) (Last accessed April 10, 2013).

manufacturer selling price, distribution chain markups, sales tax, and installation costs), operating costs (energy, repair, and maintenance costs), equipment 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 measures the amount of time it takes commercial consumers to recover the assumed higher purchase price of a more energy-efficient equipment through reduced operating costs. Inputs to the payback period calculation include the installed cost to the commercial consumer and first-year operating costs.

DOE analyzed the net effect of amended CWAF standards on commercial 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 commercial consumer (purchase price plus installation cost), operating expenses (energy expenses, repair costs, and maintenance costs), the lifetime of the equipment, and a discount rate. Inputs to the payback period calculation include the installed cost to the commercial 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 customers achieving LCC savings or incurring net cost at the considered efficiency levels.

Chapter 8 of the NOPR TSD describes the LCC and PBP analyses.

2.9 SHIPMENTS ANALYSIS

Forecasts of equipment 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 CWAF. In DOE's shipments model, shipments of equipment are driven by new construction, stock replacements, and other types of purchases.

The shipments models take an accounting approach, tracking market shares of each equipment class and the vintage of units in the existing stock. Stock accounting uses equipment shipments as inputs to estimate the age distribution of in-service equipment stocks for all years. The age distribution of in-service equipment 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 CWAF replacing old equipment, DOE used a survival function to estimate the fraction of CWAF of a given age still in operation. The survival function takes into account the equipment lifetime of CWAF, as well as the fraction of commercial consumers who choose to extend the life of their CWAF equipment by repairing rather than replacing the unit. Chapter 9 of this TSD provides additional details on the shipments analysis.

2.10 NATIONAL IMPACT ANALYSIS

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 equipment 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 equipment class are: (1) annual energy consumption per unit, (2) shipments, (3) equipment 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 equipment 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 equipment 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 equipment bought in the standards case usually

cost more than equipment 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 equipment 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 commercial consumers, DOE evaluates the potential impact of new or amended standards on identifiable groups of consumers (*i.e.*, subgroups), such as small businesses, that may be disproportionately affected by a national standard. Accordingly, DOE evaluated impacts on small businesses using the LCC and payback period spreadsheet model, using inputs appropriate to small businesses to the extent possible. The CWAF subgroup analysis is discussed in detail in chapter 11 of this TSD.

2.12 MANUFACTURER 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

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site (where applicable) combustion emissions of CO_2, NO_X, SO_2, and Hg. The second component estimates the impacts

of potential standards on emissions of two additional greenhouse gases, CH_4 and 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.

The analysis of power sector emissions uses marginal emissions factors that were derived from data in *AEO 2015*. The methodology is described in chapter 13 and 15 of the TSD.

Combustion emissions of CH_4 and N_2O are estimated using emissions intensity factors published by the EPA: GHG Emissions Factors Hub.[d] The FFC upstream emissions are estimated based on the methodology described in chapter 15 of the TSD. 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 emissions intensity factors are expressed in terms of physical units per MWh or MMBtu of site energy savings. Total emissions reductions are estimated using the energy savings calculated in the national impact analysis.

Because the on-site operation of PRODUCT requires combustion of fossil fuels and results in emissions of CO_2, NO_X, 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. Site emissions of the above gasses were estimated using emissions intensity factors from an EPA publication.[e]

The *AEO* incorporates the projected impacts of existing air quality regulations on emissions. *AEO 2015* generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of October 31, 2014.

2.14 MONETIZATION OF EMISSION REDUCTION BENEFITS

DOE considers the estimated monetary benefits likely to result from the reduced emissions of CO_2 and NO_X that are expected to accompany each of the standard levels considered.

To estimate the monetary value of benefits resulting from reduced emissions of CO_2, DOE plans to use the most current Social Cost of Carbon (SCC) values developed and/or agreed to by an interagency process. The SCC is intended to be a monetary measure of the incremental damage resulting from greenhouse gas (GHG) emissions, including, but not limited to, net

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d Available at: http://www2.epa.gov/climateleadership/center-corporate-climate-leadership-ghg-emission-factors-hub.

e U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources (Chapter 1) (Available at: http://www.epa.gov/ttn/chief/ap42/index.html).

agricultural productivity loss, human health effects, property damage from sea level rise, and changes in ecosystem services. Any effort to quantify and to monetize the harms associated with climate change will 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 provide estimates of the social benefits of reductions in GHG emissions.

The Interagency Working Group on Social Cost of Carbon released an update of its previous report in 2013.[f] The most recent estimates of the SCC in 2015, expressed in 2014$, are $12.2, $40.0, $62.3, and $117 per metric ton of CO_2 avoided. For emissions reductions that occur in later years, these values grow in real terms over time. 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. To calculate a present value of the stream of monetary values, DOE discounts 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 as to 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, these values are subject to change.

DOE also considers the potential monetary benefits of reduced NO_X emissions attributable to the standard levels it considers. 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.[g] The report includes high and low values for NO_X (as $PM_{2.5}$) for 2020, 2025, and 2030 discounted at 3 percent and 7 percent.

2.15 UTILITY IMPACT ANALYSIS

To estimate the impacts of potential energy conservation standards on the electric utility industry, DOE used published output from the NEMS associated with *AEO 2015*. NEMS is a large, multi-sectoral, partial-equilibrium model of the U.S. energy sector that EIA has developed over several years, primarily for the purpose of preparing the *AEO*. NEMS produces a widely recognized forecast for the United States through 2040 and is available to the public.

As of 2014, DOE is using a new methodology based on results published for the *Annual Energy Outlook (AEO)* Reference case, as well as a number of side cases that estimate the economy-wide impacts of changes to energy supply and demand. 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 energy conservation standards. DOE uses

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[f] 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: http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf).
[g] http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf. See Tables 4-7, 4-8, and 4-9 in the report.

the side cases to estimate the marginal impacts of reduced energy demand on the utility sector. These marginal factors are estimated based on the changes to electricity sector generation, installed capacity, fuel consumption and emissions in the *AEO* Reference case and various side cases. The methodology is described in more detail in chapter 15 of the TSD.

The output of this analysis is a set of time-dependent coefficients that capture the change in electricity generation, primary fuel consumption, installed capacity and power sector emissions due to a unit reduction in demand for a given end use. These coefficients are multiplied by the stream of electricity savings calculated in the NIA to provide estimates of selected utility impacts of new or amended energy conservation standards.

2.16 EMPLOYMENT IMPACT ANALYSIS

The adoption of energy conservation standards can affect employment both directly and indirectly. Direct employment impacts are changes in the number of employees at the plants that produce the covered products. DOE evaluates direct employment impacts in the MIA.

Indirect employment impacts may result from expenditures shifting between goods (the substitution effect) and changes in income and overall expenditure levels (the income effect) that occur due to standards. 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 product prices and reduced spending on energy.

The indirect employment impacts are investigated in the employment impact analysis using the Pacific Northwest National Laboratory's "Impact of Sector Energy Technologies" (ImSET) model.[1] 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 simple economic multiplier approaches, ImSET allows for more complete and automated analysis of the economic impacts of energy conservation investments.

2.17 REGULATORY IMPACT ANALYSIS

In the NOPR stage, DOE prepares a regulatory impact analysis (RIA) pursuant to Executive Order 12866, "Regulatory Planning and Review," 58 FR 51735 (Oct. 4, 1993). The RIA evaluates potential non-regulatory policy alternatives, comparing the costs and benefits of each to those of the proposed standards. The RIA is subject to review under the Executive Order by the Office of Information and Regulatory Affairs (OIRA) at the Office of Management and Budget (OMB).

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1. Roop, J. M., M. J. Scott, and R. W. Schultz. *ImSET: Impact of Sector Energy Technologies*. 2005. Pacific Northwest National Laboratory: Richland, WA. Report No. PNNL- 15273. (Last accessed October 15, 2015.) http://www.pnl.gov/main/publications/external/technical_reports/PNNL-15273.pdf

CHAPTER 3. MARKET AND TECHNOLOGY ASSESSMENT

TABLE OF CONTENTS

3.1 INTRODUCTION 3-1
3.2 EQUIPMENT DEFINITIONS 3-1
3.3 EQUIPMENT CLASSES 3-2
3.4 TEST PROCEDURE 3-2
3.5 MANUFACTURER TRADE ASSOCIATION 3-2
3.6 MANUFACTURER INFORMATION 3-3
3.6.1 Manufacturers 3-3
3.6.2 Potential Small Business Impacts 3-3
3.7 REGULATORY PROGRAMS 3-4
3.7.1 Current Federal Energy Conservation Standards 3-4
3.7.2 ASHRAE Standard 90.1 3-4
3.7.3 Canadian Energy Conservation Standards 3-4
3.8 NON-REGULATORY PROGRAMS 3-5
3.8.1 Federal Tax Credits 3-5
3.8.2 DSIRE database 3-5
3.9 MARKET DATA 3-5
3.9.1 Efficiency Data 3-6
3.9.2 Size Data 3-7
3.9.3 Industry Cost Structure Data 3-10
3.9.4 Industry Shipments Data 3-12
3.9.5 Distribution Channels 3-13
3.9.6 Stock Saturation 3-13
3.9.7 Product Lifetime 3-14
3.10 TECHNOLOGY ASSESSMENT 3-14
3.10.1 Equipment Characteristics and Operation 3-14
3.10.2 Technology Options 3-15
3.10.3 Technology Options that Improve Thermal Efficiency 3-15
3.10.3.1 Condensing secondary heat exchanger 3-15
3.10.3.2 Increased heat exchanger surface area 3-16
3.10.3.3 Heat exchanger enhancements 3-16
3.10.3.4 Low NOx Premix Burners 3-17
3.10.3.5 Burner De-rating 3-17
3.10.3.6 Low Pressure, Air-Atomized Burner (oil-fired CWAF only) 3-17
3.10.3.7 Concentric Venting 3-17
3.10.3.8 Pulse Combustion 3-18
3.10.3.9 High-static flame-retention head oil burner 3-18
3.10.4 Technology Options that do not improve Thermal Efficiency 3-18
3.10.4.1 Two stage or modulating combustion 3-18
3.10.4.2 Insulation Improvements 3-19
3.10.4.3 Delayed-Action Oil Pump Solenoid Valve (oil-fired CWAF only) 3-19
3.10.4.4 Off-Cycle Dampers 3-19
3.10.4.5 Electronic Ignition 3-19

LIST OF TABLES

Table 3.6.1 Major and other CWAF manufacturers 3-3
Table 3.7.1 Current Federal Energy Efficiency Standards for CWAF 3-4
Table 3.9.1 Number of CWAF Models by Equipment Class 3-6
Table 3.9.2 Air Conditioning and Warm Air Heating Equipment Industry Employment and Payroll Data 3-10
Table 3.9.3 Air Conditioning and Warm Air Heating Equipment Industry Materials and Payroll Cost Data 3-11
Table 3.9.4 Value of Air Conditioning and Warm Air Heating Equipment and Commercial and Industrial Refrigeration Equipment Shipments by Year 3-13

LIST OF FIGURES

Figure 3.9.1 Distribution of Gas-fired CWAF Models by Thermal Efficiency 3-6
Figure 3.9.2 Distribution of Oil-fired CWAF Models by Thermal Efficiency 3-7
Figure 3.9.3 Gas-fired CWAF Models by Input Capacity 3-8
Figure 3.9.4 Gas-fired CWAF Models between 225 kBtu/h and 825 kBtu/h by Input Capacity 3-9
Figure 3.9.5 Oil-fired CWAF Models by Input Capacity 3-9
Figure 3.9.6 Gas-fired CWAF Estimated Historical Shipments 3-12

CHAPTER 3. MARKET AND TECHNOLOGY ASSESSMENT

3.1 INTRODUCTION

This chapter details the market and technology assessment that the U.S. Department of Energy (DOE) has conducted in support of the direct final rule for Commercial Warm Air Furnaces (CWAF).

The goal of the market assessment is to develop a qualitative and quantitative characterization of the CWAF industry and market structure based on publicly available data and other information that DOE received directly from manufacturers and interested parties. DOE examined publicly available information from its Compliance Certification Management System (CCMS) database,[1] the Air Conditioning, Heating, and Refrigeration Institute's (AHRI) Directory of Certified Product Performance,[a,2] California Energy Commission (CEC) Appliance Efficiency Database,[3] and from manufacturers' websites and product literature. The market and technology assessment covers manufacturer characteristics, existing regulatory efficiency improvement initiatives, equipment classes, and trends in product markets and characteristics. DOE performs the technology assessment to develop a preliminary list of technologies (referred to as technology options) that could be used to improve the energy efficiency of CWAF.

3.2 EQUIPMENT DEFINITIONS

A CWAF is an integral part of a commercial building's central heating and cooling system that provides heated air to the conditioned space through ductwork. A fuel-burning furnace provides this heating by passing the combustion products through an air-to-air heat exchanger. The furnace uses a blower to propel circulation air over the outside of the heat exchanger, transferring heat from the hot combustion gases to the cool circulation air. The heated air is then distributed via ductwork to the conditioned space, and the products of combustion are exhausted from the heat exchanger to the atmosphere through the flue passage.

The Energy Policy and Conservation Act (EPCA) defines a "warm air furnace" as a self-contained oil or gas fired furnace designed to supply heated air through ducts to spaces that require it and includes combination warm air furnace/electric air conditioning units but does not include unit heaters and duct furnaces. (42 U.S.C. 6311(11)(A))

DOE reiterates the EPCA definition of warm air furnace and further defines "commercial warm air furnace" in the Code of Federal Regulations (CFR) at 10 CFR 431.72. DOE defines a commercial warm air furnace as a warm air furnace that is industrial equipment, and that has a capacity (rated maximum input) of 225,000 Btu per hour or more. DOE's current standards for CWAF are expressed as thermal efficiency (TE). DOE defines thermal efficiency in 10 CFR 431.72 as being equal to 100 percent minus percent flue loss determined using test procedures prescribed under 10 CFR 431.76.

[a] For more information see: https://www.ahridirectory.org/ahridirectory/pages/cfr/defaultSearch.aspx.

3.3 EQUIPMENT CLASSES

DOE categorized CWAF into separate equipment classes in this rulemaking. EPCA specifies the criteria that DOE used to establish equipment classes, which include: (1) the type of energy consumed; (2) capacity; or (3) other performance-related features, such as those that provide utility to the customer or other features deemed appropriate by the Secretary that would justify the establishment of a separate energy conservation standard. (42 U.S.C. 6295(q))

The initial federal energy conservation standards for CWAF were added to EPCA by the Energy Policy Act of 1992 (EPACT 1992), Public Law 102–486. (42 U.S.C. 6313(a)(4)) These types of covered equipment have a rated capacity (rated maximum input) greater than or equal to 225,000 Btu/h, can be gas-fired or oil-fired, and are designed to heat commercial buildings. CWAF are divided into two equipment classes; one for gas-fired, and one for oil-fired furnaces. At a minimum, gas-fired units must operate at an efficiency level of 80% TE, and oil-fired units must operate at an efficiency level of 81% TE.

3.4 TEST PROCEDURE

The statutory criteria for Federal test procedures require that a test procedure be reasonably designed to produce test results which reflect energy efficiency, energy use, and estimated operating costs of a type of industrial equipment (or class thereof) during a representative average use cycle (as determined by the Secretary), and shall not be unduly burdensome to conduct. (42 U.S.C. 6314 (a)(2))

The DOE test procedure for CWAF is specified in 10 CFR 431.76. This section prescribes the methods of measuring the thermal efficiency of gas-fired and oil-fired CWAF with a rated maximum input of 225,000 Btu per hour or more. The DOE test method incorporates by reference ANSI Z21.47-2006 (for gas-fired units) or UL727-2006 (for oil-fired units).

3.5 MANUFACTURER TRADE ASSOCIATION

DOE sought to identify trade groups who represent manufacturers, distributors, and installers of the CWAF equipment analyzed in this rulemaking, and identifiedAHRI as the primary trade group representing manufacturers.

AHRI represents more than 300 manufacturers of residential and commercial space heating, ventilation, air conditioning, refrigeration (HVAC&R) and water heating equipment/components sold in North America and around the world. These manufacturers account for more than 90 percent of the HVAC&R and water heating equipment manufactured and sold in North America.[b] AHRI develops and publishes technical standards, which use rating criteria and procedures for measuring and certifying performance for residential and commercial air conditioning, heating, ventilation, refrigeration and water heating equipment.

In addition to AHRI, DOE identified the Air Conditioning Contractors of America (ACCA) as a significant trade group representing the interests of installers of CWAF. ACCA represents more than 4,000 businesses in the indoor environment and energy services

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

community, building contractors, and installers of HVAC equipment. The organization provides technical, legal, and marketing resources to its members, as well as writing of standards for the design, maintenance, installation, testing, and performance of indoor environment systems. In addition, the ACCA advocates for the contracting business interests of its members on both federal and state levels.

3.6 MANUFACTURER INFORMATION

The following section details information regarding manufacturers of CWAF for sale in the United States.

3.6.1 Manufacturers

DOE compiled data for CWAF currently on the market into a single database ("DOE database") by examining the publicly-available databases discussed previously, as well as manufacturer literature. DOE identified manufacturers of CWAF based on information in the equipment directories, web-based research, review of HVAC industry publications, and discussions with manufacturers during the manufacturer interview process.

DOE identified fourteen manufacturers of CWAF that market and sell equipment in the U.S. Due to limited publicly available information, DOE is unable to disclose market share data for CWAF manufacturers. However, in Table 3.6.1 below, DOE divides manufacturers into "major" and "other" based on current industry characteristics, DOE research, and discussions with manufacturers about largest players in the CWAF market. Major companies have larger market shares.

Table 3.6.1 Major and other CWAF manufacturers

Major Manufacturers	Other Manufacturers
Carrier	Nordyne
	Modine
Johnson Controls	Thermo-Products
	Adams Manufacturing Company*
Lennox	Reznor
	Hastings Industries*
	Aaon Heating and Cooling Products
Trane	Rheem
	Daikin
	ECR International*

* This manufacturer qualifies as a small business based on the Small Business Administration threshold[4].

3.6.2 Potential Small Business Impacts

DOE takes into consideration the impact of amended energy conservation standards on domestic small businesses. Manufacturers of CWAF are identified by North American Industry Classification System (NAICS) under code 333415, "Air-Conditioning and Warm Air Heating

Equipment and Commercial and Industrial Refrigeration Equipment Manufacturing." The Small Business Administration (SBA) sets the threshold for manufacturers identified under NAICS code 333415 to be qualified as a small business as having 750 employees or fewer.[4] DOE has identified three domestic small business manufacturers – Adams Manufacturing Company, Hastings Industries, and ECR International – in the CWAF market that fall under the SBA's definition. DOE studies the potential impacts on these small business manufacturers, along with all other manufacturers, in detail in the manufacturer impact analysis (MIA), which is described in Chapter 12 of the TSD.

3.7 REGULATORY PROGRAMS

3.7.1 Current Federal Energy Conservation Standards

EPCA contains mandatory energy conservation standards for commercial heating, air-conditioning, and water-heating equipment, including CWAF (42 U.S.C. 6313(a)). As noted previously, the efficiency standards for CWAF were established by EPACT 1992 and made effective January 1st, 1994. These standards were codified in a final rule published in the *Federal Register* on October 21st, 2004 to be located contiguous with test procedures for CWAF which were promulgated by DOE in the same rule. 69 FR 61916. The current energy efficiency standards are set forth in Table 3.7.1.

Table 3.7.1 Current Federal Energy Efficiency Standards for CWAF

Fuel Type	Heating Capacity (Btu/h)	Thermal Efficiency
Gas-fired	≥225,000 Btu/h	80%
Oil-fired	≥225,000 Btu/h	81%

3.7.2 ASHRAE Standard 90.1

The American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) promulgates voluntary energy efficiency standards for CWAF. ASHRAE Standard 90.1 is an energy standard for buildings except low-rise residential buildings. ASHRAE Standard 90.1 is sometimes adopted as part of State building codes, making certain parts or all of ASHRAE Standard 90.1 mandatory for compliance with the building codes in that State. As a result, although ASHRAE Standard 90.1 is a voluntary standard, CWAF manufacturers may have to design their equipment to meet certain requirements for efficiency, ventilation and noise, contained in ASHRAE Standard 90.1 so they can be sold in certain States. Further, if ASHRAE decides to increase the efficiency standard for CWAF, then EPCA requires that DOE would be triggered to consider amended energy conservation standards for CWAF. (42 U.S.C. 6313(a)(6)(ii))

3.7.3 Canadian Energy Conservation Standards

Canada currently mandates that all gas-fired CWAF of greater than 225,000 Btu/h and less than 400,000 Btu/h input capacity have a minimum efficiency of 80% TE.[5]

3.8 NON-REGULATORY PROGRAMS

3.8.1 Federal Tax Credits

For owners and designers of new or existing commercial buildings that meet ASHRAE Standard 90.1-2001, tax deductions of up to $1.80 per square foot are available when at least 50% of heating/cooling energy is saved. Partial deductions of up to $.60 per square foot are also available for improvements made to the building envelope, lighting, or heating/cooling systems. These tax deductions are available for systems "placed in service"[c] between 1/1/2006 and 12/31/2013. By improving the thermal efficiency of a CWAF in conjunction with utilizing other more efficient heating/cooling equipment or other practices, the energy efficiency of a commercial building can potentially be reduced enough to qualify for Federal tax credits.[6]

3.8.2 DSIRE database

In addition to the federal tax credits available for purchasers of CWAF, many states and local utility companies offer rebates for higher efficiency CWAF, typically for existing buildings and retrofits only. DOE maintains a database for such rebates, called the Database of State Incentives for Renewables & Efficiency (DSIRE)[7], in addition to 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, see the DSIRE website at www.dsireusa.org.

3.9 MARKET DATA

Based on discussions with industry representatives during manufacturer interviews and publicly available product, shipment, employment, revenue, and other industry data, DOE has developed a characterization of the CWAF industry.

From the CCMS database and manufacturers' websites (of both AHRI-member manufacturers and non-AHRI-member manufacturers), DOE compiled a database of 181 unique CWAF models. Initially, DOE found approximately 2,300 units listed by these sources. DOE subsequently consolidated units together that had the same level of performance and efficiency, but had various equipment options available that were represented by additional model numbers in the original data set, but that did not affect the equipment performance. Table 3.9.1 shows the breakdown of models by equipment class for the models in DOE's database. As is shown in Table 3.9.1, the majority of the models identified on the market are gas-fired, weatherized CWAF. Gas-fired, weatherized CWAF are typically installed on a rooftop and share a common cabinet with a commercial packaged air conditioner (CUAC). Based on shipments data provided by AHRI (see section 3.9.2 of chapter 3 of the CUAC TSD for further details), DOE determined that there are little to no shipments of CWAF which share a common cabinet with a commercial package heat pump (CUHP). Aside from gas-fired, weatherized CWAF, DOE identified a significantly smaller number of models in the gas-fired, non-weatherized, and oil-fired, non-weatherized categories. DOE did not identify any CWAF that were oil-fired and weatherized.

[c] The IRS defines "placed in service" as when the property is ready and available for use (see https://www.energystar.gov/index.cfm?c=products.placed_service_popup).

Table 3.9.1 Number of CWAF Models by Equipment Class

Equipment Class	Weatherization	Number of Models	Percent of total number of Models
Gas-fired CWAF	Non-weatherized	5	2.8%
	Weatherized	162	89.5%
Oil-fired CWAF	Non-weatherized	14	7.7%
	Weatherized	0	0%

3.9.1 Efficiency Data

DOE characterized the distribution of CWAF currently available to customers by dividing the models into bins based on their efficiency and counting the number of models in each efficiency bin for each equipment class. The figures below show the distribution of efficiencies for the various equipment classes of CWAF. As shown in Table 3.9.1 above, there are no oil-fired, weatherized CWAF on the market.

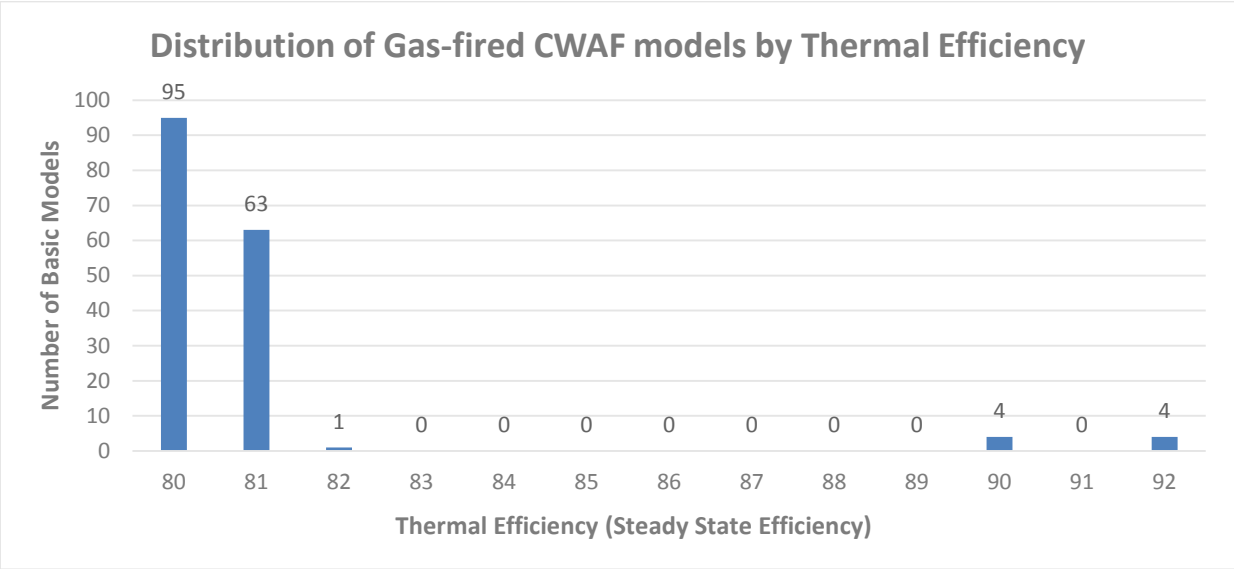

Figure 3.9.1 Distribution of Gas-fired CWAF Models by Thermal Efficiency

Figure 3.9.1 shows that 57% of gas-fired CWAF models have an efficiency of 80% TE, 38% have an efficiency of 81% TE, and one model has an efficiency of 82% TE[d]. In addition, DOE identified 8 CWAF models on the market with efficiencies of 90% and 92% TE, which were makeup air furnaces.[e] Six of these models were weatherized, two of the models at 92% TE were non-weatherized.

[d] The model identified at 82% TE was non-weatherized. In the market assessment, DOE did not identify any weatherized gas-fired CWAF in the non-condensing efficiency range (80% to 82% TE) that had an efficiency greater than 81% TE.

[e] The definition of a CWAF requires that (among other criteria) a unit be able to "supply heated air through ducts to spaces that require it" (42 U.S.C. 6311(11)(A)). Therefore, if a makeup air furnace is capable of operating in this manner, and if it meets all other criteria to be classified as a CWAF, then it would be considered as such under

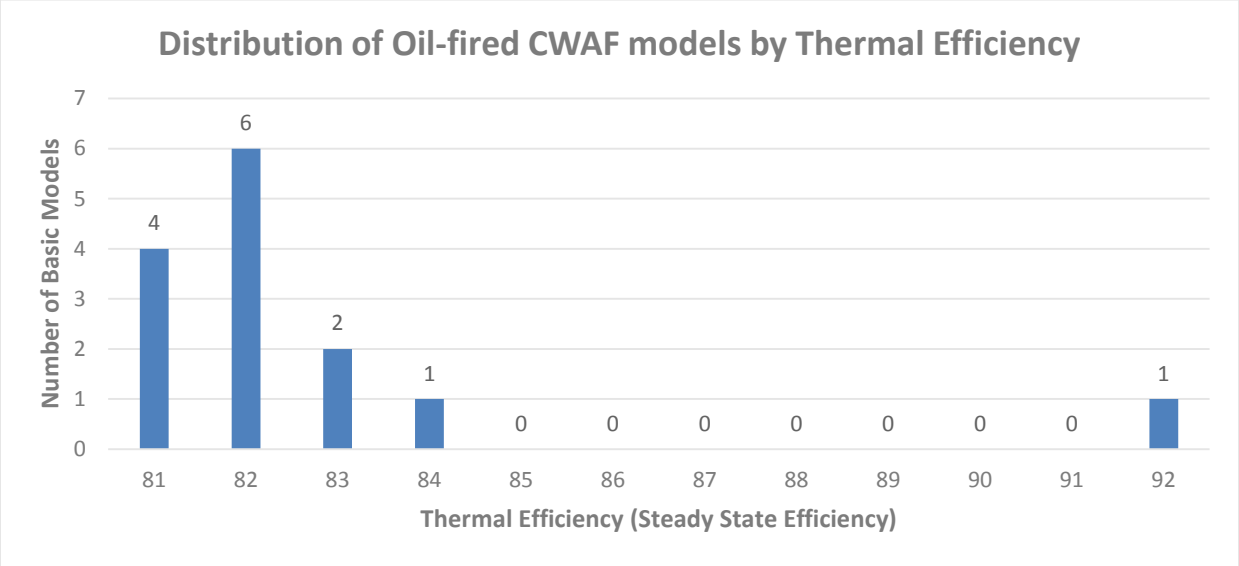

Figure 3.9.2 Distribution of Oil-fired CWAF Models by Thermal Efficiency

Figure 3.9.2 shows that most oil-fired CWAF have an efficiency of 82% TE. The least efficient unit on the market is 81% TE and the most efficient unit is 92% TE. DOE only identified one unit on the market at the 92% TE efficiency level.

3.9.2 Size Data

DOE also characterized the distribution of CWAF currently available to customers by dividing the models into bins based on their hourly heating input capacity and counting the number of models in each capacity bin for each equipment class. Figure 3.9.3 through Figure 3.9.5 show the distribution of input capacities for both CWAF equipment classes.

DOE's regulations. The makeup air furnaces considered in this market and technology assessment met the criteria to be considered as a CWAF.

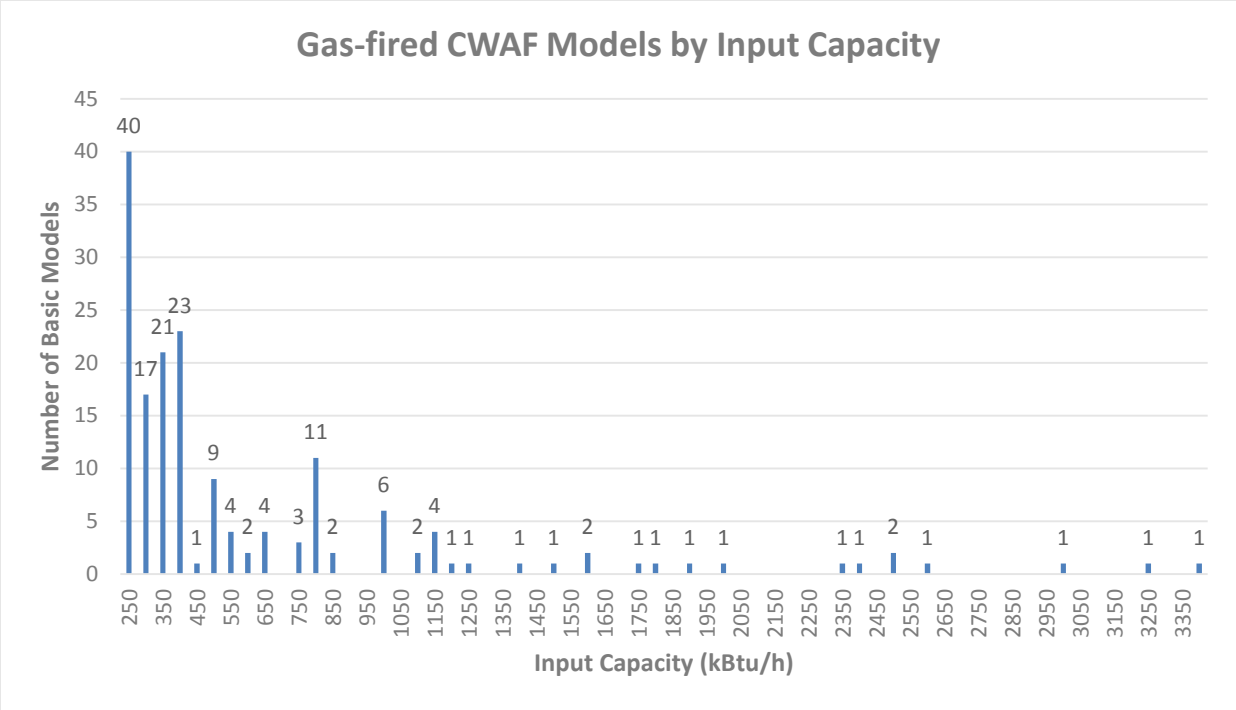

Figure 3.9.3 Gas-fired CWAF Models by Input Capacity[f]

Figure 3.9.3 shows that the heating input capacities of gas-fired CWAF span a wide range of values. The smallest unit DOE identified has a heating input capacity of 225 kBtu/h, which is the smallest capacity for a unit to be considered a CWAF under DOE's regulations. The largest unit DOE identified has a heating input capacity of 3,420 kBtu/h. The distribution of models is weighted towards the lower end of the capacity range. 81% of models have a heating input capacity less than 825 kBtu/h. The distribution of models less than 825 kBtu/h heating input capacity is shown in greater detail in Figure 3.9.4.

[f] The x-axis numerical label for each bar on the graph is the center point value of the heating input capacity range represented by that bar (e.g. the bar labeled '250 kBtu/h' represents the number of units in the greater than or equal to 225 kBtu/h and less than 275 kBtu/h heating input capacity bin).

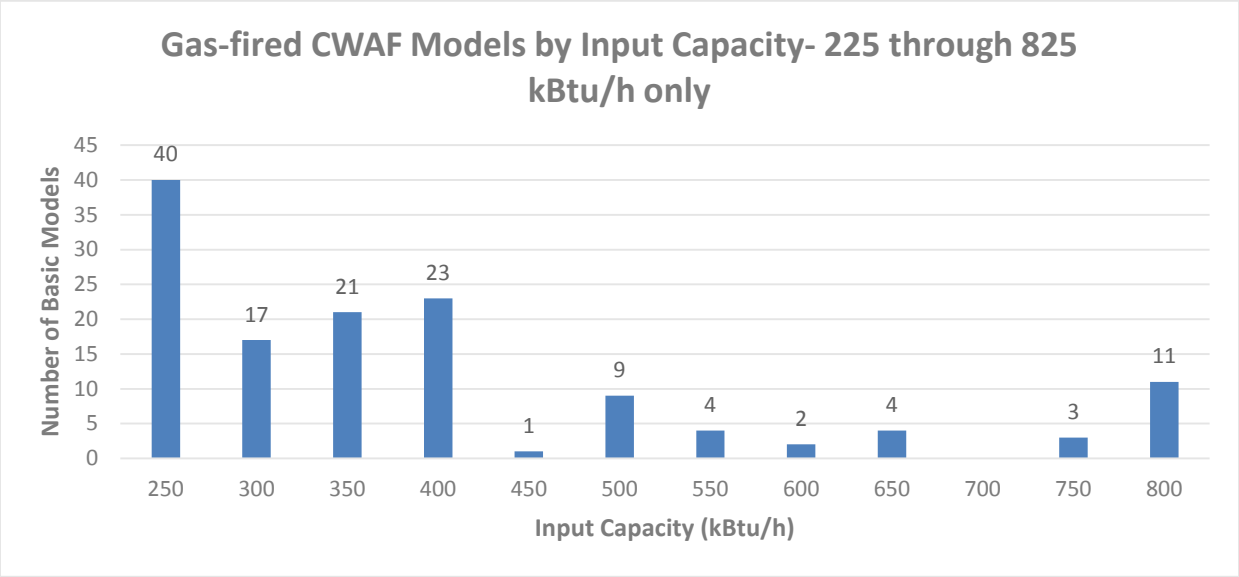

Figure 3.9.4 Gas-fired CWAF Models between 225 kBtu/h and 825 kBtu/h by Input Capacity[g]

As shown in Figure 3.9.4, in the 225 kBtu/h to 825 kBtu/h heating input capacity range, 75% of models have a heating input capacity of less than 425 kBtu/h. There are more models in the 225 kBtu/h to 275 kBtu/h capacity bin than any of the other capacity bins.

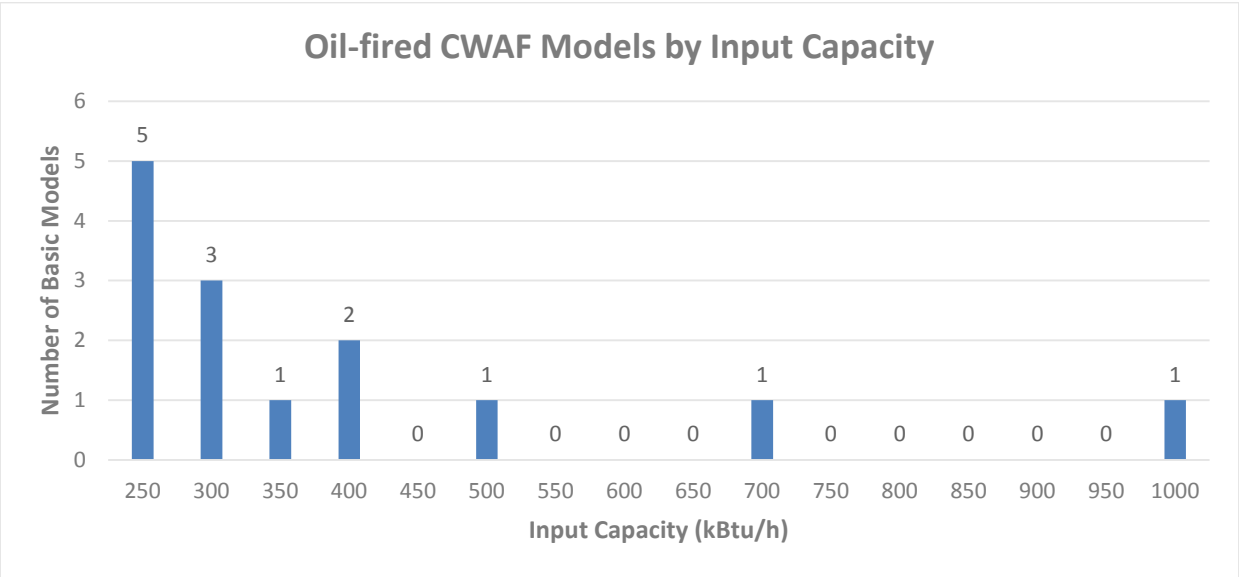

Figure 3.9.5 Oil-fired CWAF Models by Input Capacity[h]

[g] The x-axis numerical label for each bar on the graph is the center point value of the heating input capacity range represented by that bar (e.g. the bar labeled '250 kBtu/h' represents the number of units in the greater than or equal to 225 kBtu/h and less than 275 kBtu/h heating input capacity bin).

[h] The x-axis numerical label for each bar on the graph is the center point value of the heating input capacity range represented by that bar (e.g. the bar labeled '250 kBtu/h' represents the number of units in the greater than or equal to 225 kBtu/h and less than 275 kBtu/h heating input capacity bin).

Figure 3.9.5 shows that the heating input capacities of oil-fired CWAF models are mostly concentrated below 425 kBtu/h, but there are some models with heating input capacities as high as 1,000 kBtu/h. The smallest unit DOE identified has a heating input capacity of 230 kBtu/h.

3.9.3 Industry Cost Structure Data

The Census Bureau collects industry-wide employment data based on NAICS codes. Manufacturers of CWAF are grouped into the Air-Conditioning and Warm Air Heating Equipment and Commercial and Industrial Refrigeration Equipment Manufacturing category, which is NAICS code 333415.

Table 3.9.2 Air Conditioning and Warm Air Heating Equipment Industry Employment and Payroll Data[8]

	Air Conditioning and Warm Air Heating Equipment Industry Employment and Payroll Data			
Year	**Production Workers**	**Non-Production Workers**	**Total Number of Employees**	**Payroll for All Employees** ***$, thousands***
2013	64,437	24,192	88,629	$4,097,614
2012	65,577	23,217	88,794	$4,009,865
2011	62,009	21,960	83,969	$3,763,853
2010	61,668	21,693	83,361	$3,778,633
2009	60,041	26,413	86,454	$3,666,278
2008	70,772	25,730	96,502	$4,010,045
2007	74,728	26,757	101,485	$4,034,043
2006	74,909	23,188	98,097	$4,019,813
2005	76,011	26,343	102,354	$3,942,808
2004	73,106	25,929	99,035	$3,691,029
2003	77,488	27,180	104,668	$3,776,417
2002	80,417	27,857	108,274	$3,815,747
2001	88,978	29,898	118,876	$3,950,483
2000	97,978	29,406	127,384	$4,267,872
1999	95,904	28,058	123,962	$4,043,064
1998	91,994	28,017	120,011	$3,844,667
1997	90,968	28,418	119,386	$3,678,996

Table 3.9.2 shows the relationship between the cumulative number of production workers, non-production workers, total employees, and total payroll throughout the industry between the years of 1997 and 2013. The statistics illustrate a decreasing trend in both the total number of employees and the number of production workers in the industry after the year 2000. The number of non-production workers followed a decreasing trend through the year 2010, and then rebounded slightly through the year 2013.In the year 2013, the employement level of production workers was 66% of what it was in the year 2000, and the employement level of non-production workers was 82% of what is was in the year 2000. The total employment level in 2013 was 70% of what it was in the year 2000. The overall decline in employment may be a result of industry consolidation, increased automation in production, or manufacturers moving their facilities outside of the United States to reduce labor costs.

Table 3.9.3 Air Conditioning and Warm Air Heating Equipment Industry Materials and Payroll Cost Data

	Air Conditioning and Warm Air Heating Equipment Industry Cost Data			
Year	**Cost of Materials *$, thousands* (as % of shipments value)**	**Cost of Payroll; Production Workers (as % of shipments value)**	**Cost of Payroll; Non-production Workers (as % of shipments value)**	**Cost of Total Payroll *$, thousands* (as % of shipments value)**
2013	53.6	7.6	5.2	12.9
2012	53.1	7.9	5.1	13.0
2011	55.1	7.5	5.2	12.8
2010	52.6	7.8	5.6	13.4
2009	55.1	7.9	6.0	13.9
2008	54.8	8.1	5.4	13.5
2007	55.6	8.2	5.2	13.4
2006	53.2	8.9	4.9	13.8
2005	53.8	8.5	5.3	13.8
2004	51.1	8.8	5.4	14.2
2003	50.6	9.5	5.9	15.4
2002	49.4	9.8	6.1	15.9
2001	52.6	9.8	6.0	15.8
2000	53.0	10.1	5.9	16.0
1999	53.4	9.8	5.6	15.4
1998	54.9	9.9	5.5	15.4
1997	54.2	10.1	5.9	16.0

Table 3.9.3 shows the relationship between the total materials costs and the payroll costs (shown separately for production workers, non-production workers, and all employees) as a percentage of shipments value throughout the industry between the years of 1997 and 2013. The cost of materials as a percentage of value of shipments fluctuated slightly over the 17-year period, but remained relatively constant. The cost of payroll for production workers as a percentage of value of shipments followed a declining pattern, dropping from 10.1% in 1997 to 7.6% in 2013. The cost of payroll for non-production workers as a percentage of shipments fluctuated slightly during the 17-year period, but remained relatively constant. Lastly, the cost of payroll for all employees as a percentage of shipments followed a decreasing trend, dropping from 16.0% in 1997 to 12.9% in 2013.The decrease in the cost of payroll for all employees, as a percent of shipments value, is driven by the drop in production worker payroll as a percentage of shipments value. The decrease in production worker payroll as a share of shipments value is likely tied to the decrease in the total number of production workers in the industry. As mentioned previously, this may be caused by industry consolidation, increased automation in production, or outsourcing labor outside of the United States to reduce costs.

A detailed financial analysis of the manufacturers of the products covered by this rulemaking is presented in the MIA (Chapter 12 of the TSD). This analysis identifies key financial inputs including cost of capital, working capital, depreciation, capital expenditures, etc.

3.9.4 Industry Shipments Data

As part of the shipments analysis, DOE estimated historical shipments of CWAF. Historical shipments of gas-fired CWAF were not readily available, so DOE estimated these shipments based on historical shipments data for both CUACs and CUHPs. As mentioned previously, most gas-fired CWAF are weatherized and share a common cabinet with a CUAC, but not with a CUHP. However, DOE determined based on Commercial Buildings Energy Consumption Survey (CBECS) data that some buildings have both CUHP and gas-fired CWAF installed. The gas-fired CWAF in these buildings could be non-weatherized units (which are not packaged with a CUAC or CUHP). Based on CBECS data, DOE estimated that gas-fired CWAF shipments are the sum of approximately 80% of CUAC shipments and 20% of CUHP shipments. DOE approximated historical gas-fired CWAF shipments by applying these fractions to historical CUAC and CUHP shipment data.

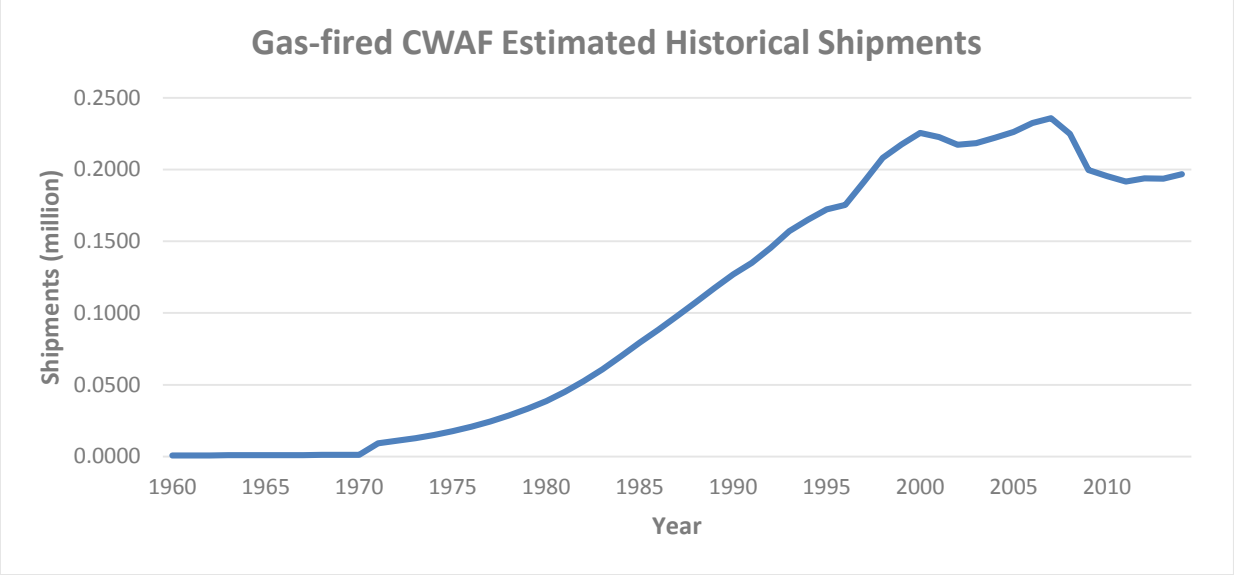

Figure 3.9.6 Gas-fired CWAF Estimated Historical Shipments

Figure 3.9.6 depicts DOE's estimates of historical gas-fired CWAF shipments. For more information on the shipments analysis for CUAC/CUHP that was used to derive gas-fired CWAF shipments, see chapter 9 of this TSD and chapter 9 of the CUAC/CUHP TSD.

For oil-fired CWAF, historical shipments data was not readily available. DOE estimated historical oil-fired CWAF shipments by multiplying historical ratios of residential oil-fired versus gas-fired furnace shipments by the estimated historical shipments of gas-fired CWAF (discussed previously). For more information on the estimated historical shipments for oil-fired CWAF, see the shipments analysis (Chapter 9) of the CWAF TSD.

Table 3.9.4 shows the total value of all shipments in the air conditioning, warm air heating, and commercial/industrial refrigeration equipment industry for the years 2007 through 2013. The value of shipments decreased by 14% between the years 2007 and 2009 (in 2014$ to account for inflation), likely due to the global economic downturn in 2008 and 2009, which decreased new building construction as well as demand for replacement equipment. However, the economic recovery since that time has brought the value of shipments back up to within 3% of its 2007 value (in 2014$).

Table 3.9.4 Value of Air Conditioning and Warm Air Heating Equipment and Commercial and Industrial Refrigeration Equipment Shipments by Year[8]

Year	Value of Shipments (not updated to account for inflation; *$, thousands*)	Value of Shipments (2014$; *$, thousands*)
2013	$31,870,187	$32,393,861
2012	$30,874,539	$31,893,381
2011	$29,503,777	$31,038,781
2010	$28,118,409	$30,192,128
2009	$26,308,906	$28,594,098
2008	$29,711,868	$32,537,977
2007	$29,908,417	$33,395,587

For more information on the shipments analysis for CWAF, including future shipments projections, see chapter 9 of the TSD.

3.9.5 Distribution Channels

There are three separate distribution channels which represent the CWAF sales market. The two most common channels are where the manufacturer sells to a wholesaler, who then sells to mechanical contractors, who either sell to the consumer directly or through a general contractor. In product replacement, the mechanical contractors ultimately provide the CWAF equipment and installation services to the consumer. In new construction, the mechanical contractors provide the CWAF equipment and installation services to the general contractor who then sells to the consumer. In the other, less common channel, the manufacturer sells directly to the consumer. The mechanical and/or general contractor is not included in this distribution channel because installation services are sought by the building owner independent of the CWAF purchase. The distribution channels are discussed in detail in the markups analysis (Chapter 6 of the TSD).

3.9.6 Stock Saturation

Stock saturation refers to the percentage of commercial and/or industrial building stock utilizing a specific type of equipment or exhibiting a certain feature. DOE used the Energy Information Administration (EIA) Commercial Building Energy Consumption Survey (CBECS) in 2012 (most recently published survey) to approximate the stock saturation of CWAF. CBECS quantifies the number of commercial buildings that use electricity, natural gas, fuel oil, district

heat, district chilled water, propane, and/or other energy sources for a variety of end uses, including space heating, cooling, water heating, cooking, manufacturing, and electricity generation. The CBECS 2012 data showed that there are 5.56 million commercial buildings in the U.S., and 4.72 million (85%) utilize space heating equipment. Among them, 3.39 million (61% of all buildings in the survey) use either natural gas and/or propane, and 0.46 million (8% of all buildings in the survey) use fuel oil, for a variety of end uses. Some buildings that use space heating equipment and either natural gas, propane, or fuel oil may not use any of these fuels for the purpose of space heating (rather, they may use it for cooking, water heating, etc.). Also, natural gas and/or propane are commonly used to fuel gas-fired CWAF, but may also be used to fuel other types of gas-fired space heating equipment (such as boilers, unit heaters, etc.). Similarly, fuel oil may be used to fuel oil-fired space heating equipment other than oil-fired CWAF (such as boilers). For these reasons, the stock saturations of gas-fired CWAF and oil-fired CWAF are less than the aforementioned 61% and 8% of commercial buildings that use each of these fuels (and also have space heating equipment), respectively. More detailed information on the stock saturations of gas-fired CWAF and oil-fired CWAF is contained in the Energy Use Analysis (see Chapter 7 of the TSD).

3.9.7 Product Lifetime

The lifetime of CWAF can vary greatly depending on how often the CWAF 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. Gas-fired CWAF account for a large majority of the CWAF market and as mentioned previously, are typically packaged with a CUAC in a weatherized rooftop unit. With regular maintenance and servicing, CWAF are generally less prone to equipment failure than CUAC.[9] Because CUAC are more prone to equipment failure than CWAF, and failure of the CUAC would likely require replacement of the entire rooftop unit (including the CWAF), the equipment lifetime of CUAC is most representative of the service lifetime of CWAF. In the life-cycle cost and payback period analysis (see chapter 8 of the TSD), DOE based the CWAF lifetime probability distribution on CUAC equipment lifetime developed in the CUAC shipments analysis, which resulted in an average lifetime of 23 years. For a detailed discussion of the development of furnace lifetimes, see Appendix 8-F of the TSD.

3.10 TECHNOLOGY ASSESSMENT

This section provides a technology assessment for CWAF. This technology assessment presents details about equipment characteristics and operation, and an examination of possible technological improvements for CWAF.

3.10.1 Equipment Characteristics and Operation

CWAF use either natural gas, propane, or heating oil as a fuel. CWAF contain two main components – the burner and the heat exchanger – and also use an air circulating blower that is commonly shared with the air conditioning components of the HVAC system. The burner ignites the fuel, and the hot combustion gases are then drawn through an air-to-air heat exchanger. The blower moves circulation air over the heat exchanger, which warms the circulation air

surrounding the heat exchanger to be conditioned for heating the building space. After the hot combustion gases pass through the heat exchanger, the exhaust ('flue') gases exit the heat exchanger through an exhaust vent or pipe. The greater the surface area the gases are exposed to in the heat exchanger, the greater the heat transferred to the supply air to the building (with all other parameters being equal). The greater the heat that gets transferred to the building, the better the utilization of energy available in the fuel, and the higher the efficiency of the furnace.

In CWAF, the major components can be arranged either vertically or horizontally. Typically, CWAF are installed in a horizontal orientation, but in some scenarios, particularly in indoor (non-weatherized) installations, the units are installed vertically to save floor space.

Four primary sources of energy consumption exist in a CWAF: The burner, which ignites the heating fuel, the electricity needed for the fuel ignition to continuously operate, the combustion fan[i], and the indoor blower fan which pushes air over the heat exchanger to supply heat to the building. In a commercial application, because the indoor blower fan generally runs continually during occupied hours to provide ventilation to the building, its energy consumption throughout the course of the year can be large relative to the other electrical components in the CWAF.

3.10.2 Technology Options

In order to gain a deeper understanding of the technological improvements that may be used to increase the efficiency of CWAF, DOE examined the most common improvements used in today's market (including both the CWAF market and the markets for other space heating equipment), discussed technology options with manufacturers, reviewed industry publications, and also researched technical journals, patent filings, and other sources for prototype designs that have not yet been commercialized.

The purpose of the technology assessment is to develop a list of all technologies that could be used to improve the energy efficiency of CWAF. However, some technologies that may improve efficiency of CWAF when operating in the field do not impact the thermal efficiency as measured by the DOE test procedure. These technologies are listed separately in this assessment for informational purposes.

3.10.3 Technology Options that Improve Thermal Efficiency

3.10.3.1 Condensing secondary heat exchanger

Installing a secondary heat exchanger on the furnace extracts additional heat from the combustion products, which increases thermal efficiency. The installation of a secondary heat exchanger necessitates a larger combustion inducer fan with an upgraded housing, as well as stainless steel impellers. Furnace efficiency increases due to both the additional heat loss from

[i] In gas-fired CWAF, the combustion fan (which may also be called a 'combustion inducer fan' or 'combustion inducer motor') is located downstream of (after) the heat exchanger with relation to the flow of combustion products. The fan creates negative pressure in order to entrain fuel and air for combustion to the ignitor. In oil-fired CWAF, the combustion fan is part of the burner assembly, and is used to provide a mixture of heating oil and combustion air at positive pressure to the ignitor.

the combustion gases, as well as the energy captured from the subsequent phase change of the combustion products from a gas to a liquid upon sufficient cooling (i.e., the latent heat of vaporization). When enough heat is extracted from the flue gases, they are cooled below the dew point and acidic condensation begins to form inside the secondary heat exchanger, which necessitates that the heat exchanger be constructed out of a corrosion resistant material. This acidic condensate is typically collected in a corrosion-resistant pan and drained away from the furnace through a neutralizing material (e.g., limestone rocks), and then commonly passed to the local sewer system. If local code permits, the condensate may be passed directly to the sewer system, bypassing the neutralization step; however, this is a less common method of condensate disposal. In weatherized installations, if the condensate is exposed to sub-freezing outdoor temperatures, it could freeze before it reaches the disposal point. This requires that the condensate be heated in some manner to keep it above freezing while it flows from the furnace to the disposal drain. One way to ensure that the condensate receives ample heat is to wrap the condensate drainage pipes in electrical heat tape.

3.10.3.2 Increased heat exchanger surface area

By increasing the surface area of the heat exchanger in a furnace, the ratio of heat exchanger surface area to input energy increases, which raises the proportion of heat energy input to the furnace that gets transferred to the building air stream, thus increasing the thermal efficiency of the furnace. However, manufacturers are only able to increase heat exchanger surface area to a certain point because once enough heat has been extracted from the flue gases, the gases will begin to condense, causing acidic condensate to collect in the heat exchanger that can corrode through the heat exchanger material. Increasing the heat exchanger surface area may necessitate a larger combustion inducer motor, in order to overcome the increased pressure drop of the increased heat exchanger area. The larger combustion inducer motor itself does not lead to a higher thermal efficiency; however, it allows for the implementation of other technologies (i.e. heat exchanger improvements), that would cause the furnace to operate more efficiently.

3.10.3.3 Heat exchanger enhancements

There are several methods of increasing the thermal efficiency of a furnace by modifying the heat exchanger without adjusting its size. These improvements are accomplished by either altering the outside surface of the heat exchanger or modification of the inside of the heat exchanger. One common method is to incorporate dimples onto the exterior of the heat exchanger to increase turbulence of the return air flowing over the heat exchanger surface, thus enhancing heat transfer. Another common heat exchanger improvement is the installation of turbulators, which are very thin, twisted strips of stainless steel inserted longitudinally into the tubes of the heat exchanger, parallel to the airflow. Turbulators restrict the flow of air in the heat exchanger tubes, which increases the turbulence of the combustion gases as they pass through the heat exchanger tubing. This increased turbulence intensifies the collisions of combustion gas molecules with the heat exchanger walls, which improves heat transfer. Manufacturers may also install heat exchanger baffles; baffles are fins or extrusions from the interior walls of the heat exchanger which deflect the combustion gases toward the heat exchanger walls as they flow through the heat exchanger. Similar to turbulators, baffles intensify the collisions of combustion molecules with the heat exchanger tubing, which improves heat transfer.

3.10.3.4 Low NOx Premix Burners

Low NO_X premix burners mix the primary air and the fuel prior to combustion, which reduces or eliminates the need for secondary air and results in more complete combustion. A uniform flame shape is also created which ensures oxygen availability to all regions of the flame. The lower levels of excess air result in a hotter and leaner flame. The enhanced flame raises the temperature of gases entering the heat exchanger, which improves heat transfer and thus thermal efficiency. It also raises the water vapor dew point in the gas, which further facilitates condensation and improves thermal efficiency in a condensing furnace. Premix burners have lower NO_X emissions than traditional burners.

3.10.3.5 Burner De-rating

Decreasing the burner firing rate to increase the ratio of heat transfer area to fuel input, or "burner de-rating", can increase the thermal efficiency rating of gas-fired and oil-fired furnaces. However, because heat output rate is directly related to burner size, de-rating also reduces the amount of heated air available to the customer. This reduction in heat output adversely affects the utility to customers.

3.10.3.6 Low Pressure, Air-Atomized Burner (oil-fired CWAF only)

To overcome the low input limitations of conventional oil burners, Brookhaven National Laboratory (BNL) developed a low-pressure, air-atomized oil burner that can operate at firing rates as low as 0.25 gallons of oil per hour (10 kW). In addition, it can operate with low levels of excess combustion air (less than 10 percent) for lean-burning, ultra-clean combustion. A lower level of excess air generally improves the thermal efficiency rating of an oil-fired furnace. This burner design is also capable of firing fuel at a high or low input rate, which is manually actuated by a switch. When the furnace is installed in well-insulated modern homes, the actuation of input rates allows the burner to closely match the smaller heating loads of these structures.

While tests performed at BNL seem to have successfully demonstrated enhanced oil-fired boiler efficiency performance by using a low-pressure, air-atomized burner (per the DOE test procedure for furnaces and boilers), the prototype was never tested on a furnace. Therefore, the technological feasibility of the burner prototype for incorporation into an oil-fired CWAF remains unknown.

3.10.3.7 Concentric Venting

In a furnace utilizing a concentric venting apparatus, the exhaust gases flow through a pipe which is surrounded by a concentric combustion air intake passage. The heat transfer through the vent wall enables some of the exhaust gases to preheat the intake of combustion air before it comes in contact with the burner. Concentric venting is only used in non-weatherized installations. There is very limited use of concentric venting for CWAF, since the large majority of the applications of CWAF are weatherized. However, in residential applications, furnaces with concentric venting can achieve an efficiency enhancement of a few tenths of a percent annual fuel utilization efficiency (AFUE), so small efficiency enhancements in CWAF may also be possible.

3.10.3.8 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). The primary advantage of pulse combustion is the pulses of exhaust create a high level of turbulence in the heat exchanger. This improves heat transfer which thus raises thermal efficiency. Pulse combustion systems are also capable of venting without the assistance of mechanical draft. Because the pulse combustion process is very efficient, pulse combustion is generally used in conjunction with a condensing secondary heat exchanger.

In contrast to natural draft and induced draft furnaces, pulse combustion furnaces generate positive pressure in the heat exchanger. Positive pressure in the heat exchanger has the potential to create a possible safety problem because combustion products can contaminate the circulation-air stream if the heat exchanger breeches.

Pulse combustion gas furnaces were available in the United States for more than two decades. However, they were withdrawn from the market because manufacturers found that competing technologies, such as condensing secondary heat exchangers utilizing induced draft, cost less to manufacture and provide comparable efficiency and performance.

3.10.3.9 High-static flame-retention head oil burner

Most modern oil-fired furnaces use flame-retention head oil burners, which significantly increase the efficiency of combustion in oil-fired furnaces, as compared to oil-fired furnaces in the past which used cast-iron head burners. Flame-retention head burners, as compared to cast-iron head burners, significantly increase the degree to which heating oil and combustion air are mixed together, which reduces the amount of excess air required for combustion, and results in a tighter, hotter flame. This increase in flame temperature reduces the amount of fuel needed to achieve desired heating loads, which saves energy. Flame-retention head burners with high-static pressure can run at even lower excess air levels than standard flame-retention head burners, and can increase the thermal efficiency of a furnace by several percentage points.[10]

3.10.4 Technology Options that do not improve Thermal Efficiency

3.10.4.1 Two stage or modulating combustion

Through the use of two-stage or modulating combustion, the fuel input rate into a furnace can be decreased in conjunction with the combustion inducer fan operating at a lower corresponding speed, in order to ensure a constant ratio of combustion air to combustion fuel. When a building with a single-setting furnace faces a reduced heating load, the furnace runs for a shorter amount of time to reach the desired temperature. However, the temperature oscillations in the building (as the furnace stabilizes the temperature at the target point) can be decreased if the furnace heats the building at a slower rate, as can be accomplished with two-stage and

modulating furnaces. Two-stage and modulating furnaces do not have an improved thermal efficiency over their single stage counterparts, because the DOE test procedure for thermal efficiency only measures performance at the maximum heating input rate. However, two-stage and modulating combustion can improve annual utilization of heating fuel.

3.10.4.2 Insulation Improvements

The cabinets of furnaces are typically insulated with fiberglass. Heat loss through fiberglass insulation can be decreased by increasing the thickness of the insulation. However, insulating furnaces with foam, a vacuum, inert gases, aerogel, or evacuated panels can be an alternative to the typical method of decreasing jacket heat loss by increasing insulation thickness. Manufacturers may elect to use alternative types of insulation because increasing the thickness of insulation may create shipping and installation problems if the footprint exceeds typical dimensions. Although improving insulation will reduce jacket losses and decrease overall CWAF energy use in practice, insulation improvements do not impact CWAFefficiency as measured by the DOE test procedure because jacket losses are not included in the calculation of thermal efficiency.

3.10.4.3 Delayed-Action Oil Pump Solenoid Valve (oil-fired CWAF only)

In oil-fired furnaces, after the ignitor is charged and the combustion fan begins operating, the oil pressure in the oil injection pump increases to a peak value. If the oil insertion valve is opened prior to the oil reaching peak pressure, some of the oil can drip onto the burner, which results in incomplete combustion of the oil at the start of the burning process. To eliminate this problem, a delayed-action oil pump solenoid valve can be installed between the oil pump and the burner nozzle to supplement the oil pump regulator. The delayed-action oil pump solenoid valve allows the oil insertion valve to open only when the oil pressure has reached its peak value. It does so by delaying the oil release by three to six seconds after the ignitor and combustion fan 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 thermal efficiency.

3.10.4.4 Off-Cycle Dampers

When installed, off-cycle dampers can be located at both ends of the heat exchanger(s), and close during the furnace's off cycle in order to trap the heat generated by the furnace during operation from escaping through the exhaust vent or through the combustion air intake. In addition, dampers prevent conditioned air from escaping the building through the furnace and up the flue while the furnace is not operating. This improves AFUE (which accounts for off cycle losses including infiltration), but does not improve thermal efficiency, which is a measure of the active mode efficiency. Also, conditioned air can only enter the furnace and escape up the flue in non-weatherized units, which make up a small minority of CWAF installations. Therefore, the potential overall energy savings offered by this technology option are minimal.

3.10.4.5 Electronic Ignition

Modern gas-fired furnaces typically use electronic ignition to light either the natural gas or propane flowing into the furnace. In the past, ignition systems commonly relied on a pilot light being lit constantly to provide immediate ignition to the furnace upon opening the main gas valve. These systems wasted a significant amount of gas in order to keep the pilot light fueled while the furnace was not operating. Electronic ignition systems save a substantial amount of annual fuel consumption by eliminating the need for a constantly-lit pilot light to ignite the gas flowing into the furnace. However, because this technology primarily reduces fuel consumption during standby periods, it will not improve the thermal efficiency of gas-fired CWAF, which is a measurement of active mode efficiency. Electronic ignition in gas-fired furnaces is accomplished using either hot surface ignition (HSI) or direct spark ignition (DSI). Oil-fired furnaces only use DSI.[10]

For HSI, the ignitor is an electrical element placed in the flow of gas entering the burner. Electricity flows through the element, causing it to glow red hot. Once the element reaches the proper temperature, the gas valve is opened, which introduces gas to the burner to be lit by the heating element. A flame sensor sends a small electrical current through the flame area to detect the presence of a flame based on perturbations to the current, and shuts off voltage to the heating element upon confirmation that a flame is present. The flame sensor uses either current passing through the heating element or a remote flame sense rod to detect the flame.

DSI uses a spark to directly ignite the heating fuel (either oil or gas) flowing through the furnace. On a call for heat, current begins to flow through an electrode, which emits sparks that subsequently arc into the fuel flow. Once the presence of a flame is detected, the electrode stops producing sparks. To detect the flame, either the same electrode that lights the flame is used as a flame sensor, or a remote flame sense rod is used to detect the presence of a flame in the burner by producing a small amount of current through the flame area.

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CHAPTER 4. SCREENING ANALYSIS

TABLE OF CONTENTS

4.1 INTRODUCTION 4-1
4.2 SCREENED-OUT TECHNOLOGIES 4-2
4.2.1 Pulse Combustion 4-2
4.2.2 Low NO_X Premix Burner 4-3
4.2.3 Low Pressure, Air-Atomized Burner (oil-fired CWAF only) 4-3
4.2.4 Burner De-rating 4-3
4.3 TECHNOLOGIES THAT DO NOT IMPACT THERMAL EFFICIENCY AS MEASURED BY THE DOE TEST PROCEDURE 4-3
4.3.1 Two-stage or Modulating Combustion 4-4
4.3.2 Insulation Improvements 4-4
4.3.3 Off-Cycle Dampers 4-4
4.3.4 Delayed-Action Oil Pump Solenoid Valve (oil-fired CWAF only) 4-4
4.3.5 Electronic Ignition 4-5
4.4 TECHNOLOGY OPTIONS COMMONLY FOUND IN BASELINE UNITS 4-5
4.5 TECHNOLOGY OPTIONS WITH INSUFFICIENT INFORMATION REGARDING ENERGY EFFICIENCY BENEFITS 4-6
4.5.1 Concentric Venting 4-6
4.6 REMAINING TECHNOLOGY OPTIONS 4-7

LIST OF TABLES

Table 4.4.1 Technologies Found in Common Baseline Gas-fired CWAF Designs 4-6
Table 4.4.2 Technologies Found in Common Baseline Oil-fired CWAF Designs 4-6
Table 4.6.1 Technology Options for CWAF Passed Through to the Engineering Analysis 4-7

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 Commercial Warm Air Furnaces (CWAF). In Chapter 3, the market and technology assessment, DOE presented an initial list of technology options that can be used to reduce energy consumption of CWAF. 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 DOE analysis 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 that are not incorporated in commercial products or in working prototypes or 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 are eliminated from consideration, following the guidance of 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i-iv). Some of these technologies can reduce the annual energy consumption of CWAF in actual applications but may not improve the thermal efficiency of CWAF as measured by the DOE test procedure. Such technologies also are not passed on to the engineering analysis for consideration because they would not be implemented as a result of more stringent energy conservation standards.

The Energy Policy and Conservation Act (EPCA) establishes criteria for prescribing new or amended standards designed to achieve the maximum improvement in energy efficiency. Further, EPCA directs the Secretary of Energy to determine whether a standard is technologically feasible and economically justified. (42 U.S.C. 6313(a)(6)(A)(ii)(II)). EPCA also establishes guidelines for determining whether a standard is economically justified. (42 U.S.C. 6313(a)(6)(B)(ii)) 10 CFR 430, "Procedures, Interpretations and Policies for Consideration of New or Revised Energy Conservation Standards for Consumer Products" sets forth procedures that DOE generally uses to guide its consideration and promulgation of new or revised equipment energy conservation standards. These procedures elaborate on the statutory criteria provided in EPCA and, in part, eliminate problematic technologies early in the process of prescribing or amending an energy conservation standard. In particular, DOE uses 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i-iv) to guide its determination as to whether to eliminate from consideration any technologies that present unacceptable problems with respect to the following criteria:

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 of a technology in commercial products and reliable installation and servicing of the technology 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 equipment availability. If DOE determines a technology would have a significant adverse impact on the utility of the equipment to significant subgroups of customers, or would result in the unavailability of any covered equipment type with performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as equipment 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.

In sum, if DOE determines that a technology, or a combination of technologies, has unacceptable impacts based on the factors identified in 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i-iv), it will be eliminated from consideration. If a particular technology fails to meet one or more of the four criteria, it will be screened out. Further, certain technology options may be removed from consideration if it is determined that (1) they do not impact the efficiency metric as measured by the current test procedure; or (2) they are already found in baseline units. Sections 4.3 and 4.4 list the technologies that were removed from consideration for these respective reasons. Lastly, for certain technologies that pass the screening analysis, there may be little or no information available regarding their potential efficiency benefits, making them difficult to assess further in the engineering analysis. These technologies are addressed in section 4.5.

4.2 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 equipment utility or equipment availability; and (4) adverse impacts on health or safety. DOE eliminated four technologies for failure to meet these criteria.

4.2.1 Pulse Combustion

Pulse combustion burners operate on self-sustaining resonating pressure waves. The main advantage of this method of combustion is that the combustion products flow through the heat exchanger and through the exhaust vent all on their own, without the need for any sort of mechanism to assist them (*i.e.*, an inducer motor). DOE could only identify non-weatherized furnaces that have employed pulse combustion technology in the past.

The positive pressure that is generated in the heat exchanger of pulse combustion furnaces, as discussed in Chapter 3 of this TSD, could potentially be a safety hazard if the heat exchanger were to breach and combustion gases were to leak via the supply air stream into the occupied space. If there were any failure in the heat exchanger causing an opening, the flue products could potentially escape into the supply air stream due to the pressure differential caused by the positive pressure in the combustion chamber. The pulse combustion process is also louder than a more traditional burner. Mufflers and insulation reduce the noise, but don't totally eliminate it. In some installations, the excessive noise created by pulse combustion furnaces

might cause a reduction in customer utility compared to other furnaces using conventional combustion methods.

Pulse combustion furnaces were available for two decades but there are currently none available on the market because manufacturers discovered that other efficiency improving technologies such as condensing heat exchangers were less expensive. Due to potential safety concerns, potential loss of utility due to excessive noise, and the availability of less costly technologies that achieve the same efficiency, DOE eliminated pulse combustion from further consideration in the engineering analysis.

4.2.2 Low NO_X Premix Burner

Premix burners work by completely mixing primary air and fuel prior to combustion, eliminating the need for secondary air. However, atmospheric burners cannot entrain sufficient primary air to completely premix the air and gas. Therefore, to ensure sufficient and complete mixing, the burner incorporates a fan to deliver combustion air at positive pressure. To the extent of DOE's knowledge, low NO_X premix burners have not yet been successfully incorporated into a CWAF design; and technological feasibility in a furnace has not been proven. For this reason, DOE did not consider this technology option further in the rulemaking analyses.

4.2.3 Low Pressure, Air-Atomized Burner (oil-fired CWAF only)

To overcome the low input limitations of conventional oil burners, Brookhaven National Laboratory (BNL) developed a low-pressure, air-atomized oil burner that can operate at firing rates as low as 0.25 gallons of oil per hour (10 kW) and corresponding lower levels of excess combustion air. A lower level of excess air generally improves thermal efficiency rating.

While tests performed at BNL seem to have successfully demonstrated enhanced oil boiler efficiency performance per the DOE test procedure for furnaces and boilers, the prototype was never tested on a CWAF. Therefore, the technological feasibility of the burner prototype for incorporation into an oil-fired CWAF remains unknown, and DOE does not consider low-pressure, air-atomized oil burners to be a viable technology for thermal efficiency improvement at this time.

4.2.4 Burner De-rating

Decreasing the burner size to increase the ratio of heat transfer area to fuel input, or "burner de-rating", can increase the thermal efficiency rating of gas-fired and oil-fired CWAF. However, because heat output rate is directly related to burner size, de-rating also reduces the amount of heated air available to the customer. This reduction in heat output adversely affects the utility to customers. Therefore, DOE did not consider this technology option further in the rulemaking analyses.

4.3 TECHNOLOGIES THAT DO NOT IMPACT THERMAL EFFICIENCY AS MEASURED BY THE DOE TEST PROCEDURE

DOE eliminated four technologies because they have no effect on or do not increase thermal efficiency as measured by the DOE test procedure because the test procedure measures steady-state efficiency and does not account for jacket losses. However, these technologies can reduce the energy consumption of CWAF in actual applications since they affect cyclic operation. Although these technologies were not considered in the engineering analysis, 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 thermal efficiency.

4.3.1 Two-stage or Modulating Combustion

When a building with a single-setting furnace faces a reduced heating load, the furnace runs for a shorter time period to reach the desired temperature, but often overshoots the target temperature, which causes subsequent on/off cycling of the furnace and oscillations in temperature until the target is reached. Using a furnace with two-stage or modulating combustion significantly reduces these oscillations and the extra fuel used by on/off cycling by decreasing the rate of heating as the target temperature is approached. Two-stage and modulating combustion can significantly reduce energy consumption over time, but it has no effect on the efficiency rating of CWAF, because the DOE test procedure for CWAF only measures efficiency at the maximum heating input rate. Therefore, DOE eliminated two-stage and modulating combustion from further consideration in the rulemaking analyses.

4.3.2 Insulation Improvements

Decreasing heat loss through the jacket of the furnace by using insulation comprised of foam, a vacuum, inert gases, aerogel, or evacuated panels is an alternative to increasing the thickness of standard fiberglass cabinet insulation. Using alternative types of insulation may solve shipping and installation problems caused by the larger footprint of thicker fiberglass insulation material. However, DOE notes that jacket losses are not accounted for in the thermal efficiency metric as defined in the DOE test procedure for CWAF (see 10 CFR 431.76) and thus, insulation improvements would not impact the thermal efficiency rating. For this reason, DOE eliminated insulation improvements from further consideration in the rulemaking analysis.

4.3.3 Off-Cycle Dampers

When installed, off-cycle dampers are located at both ends of the heat exchanger(s), and close during the furnace's off-cycle to trap heat generated by the furnace from escaping through the exhaust vent or combustion air intake. In non-weatherized installations, these dampers also prevent conditioned air from escaping the building and through the furnace exhaust during off periods. Off-cycle dampers do not improve thermal efficiency, because the thermal efficiency metric only accounts for efficiency during active mode operation. Therefore, DOE eliminated this technology option from further consideration in the rulemaking analyses.

4.3.4 Delayed-Action Oil Pump Solenoid Valve (oil-fired CWAF only)

A delayed-action oil pump solenoid valve prevents oil from entering the oil burner until the oil is at peak pressure. This prevents oil from dripping onto the burner at the start of the combustion process, which would result in incomplete combustion. Over a long period of time, these devices improve the total utilization of oil input to the furnace at the beginning of each run cycle; however, they provide no improvement to the thermal efficiency of an oil-fired CWAF since the thermal efficiency metric only accounts for operation at maximum heat input for a relatively short period of time. For this reason, DOE eliminated this technology option from further consideration in the rulemaking analyses.

4.3.5 Electronic Ignition

Electronic ignition for CWAF is not a federally mandated technology, but it is used in effectively all CWAF because it is listed as a requirement in ASHRAE 90.1. Electronic ignition systems are typically either hot surface ignition (HSI) or direct spark ignition (DSI). Both systems provide sufficient energy to light heating fuel at the maximum heat input rate without the need for a pilot light. In the past, furnace ignition was provided by means of a pilot light, which would constantly remain lit while the furnace was in standby operation in order to allow instantaneous ignition on a call for heat. Using electronic ignition in place of a pilot light saves a substantial amount of heating fuel that would otherwise be used to power the pilot light. The DOE test procedure for the energy efficiency of CWAF accounts for the thermal efficiency of the CWAF while in active operation at the maximum heat input rate, and does not account for energy use during periods of standby operation. Since the savings in heating energy resulting from the use of electronic ignition are only realized during periods of standby operation when the main burner is not firing, DOE did not consider this technology option further in the engineering analysis.

4.4 TECHNOLOGY OPTIONS COMMONLY FOUND IN BASELINE UNITS

After eliminating those technologies that do not increase thermal efficiency and screening out those technologies that do not meet the requirements of 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i-iv), DOE identified technologies that are already commonly found in baseline CWAF as listed in Table 4.4.1 and 4.4.2. Although DOE did not consider most of these technologies as options for improving the efficiency of CWAF in comparison to the baseline, the costs of these components were captured in the engineering analysis at the baseline efficiency level. For certain components, DOE lists multiple technologies if there is more than one type of component commonly found in baseline equipment.

Table 4.4.1 Technologies Found in Common Baseline Gas-fired CWAF Designs

Gas valve: Single stage, two-stage, or modulating
Burners: In-shot
Ignition: Hot Surface Ignition (HSI) or Direct Spark Ignition (DSI)
Primary heat exchanger: Aluminized steel; tubular, clamshell, or serpentine shaped
Draft inducer fan: Permanent Split Capacitance (PSC) motor (single or multi-speed)
Blower fan: PSC motor (single or multi-speed) or Brushless Permanent Magnet (BPM) motor (multi-speed or modulating speed)

Table 4.4.2 Technologies Found in Common Baseline Oil-fired CWAF Designs

Oil nozzle: Single setting or two setting
Burners: Flame-retention head burner
Ignition: Interrupted Duty Ignition
Primary heat exchanger: Aluminized or stainless steel drum
Combustion fan: PSC motor (single or multi-speed)
Blower fan: PSC motor (single or multi-speed) or BPM motor (multi-speed or modulating speed)

4.5 TECHNOLOGY OPTIONS WITH INSUFFICIENT INFORMATION REGARDING ENERGY EFFICIENCY BENEFITS

DOE identified a particular technology which passed all four of the screening criteria listed in section 4.2, but did not have any available, identifiable documentation demonstrating the magnitude of its potential improvements to the overall energy efficiency of a CWAF. Because this technology passed the screening criteria, it was passed to the engineering analysis; however, DOE had no means of studying its potential energy efficiency benefits relative to the other technologies analyzed.

4.5.1 Concentric Venting

In a furnace utilizing a concentric venting apparatus, the exhaust gases flow through a pipe which is surrounded by a concentric intake air passage. The heat transfer through the vent wall enables some of the exhaust gases to preheat the intake air before it comes in contact with the burner. Concentric venting is only used in non-weatherized installations. For commercial applications, there is very limited information on the energy efficiency benefits of concentric venting because this technology is used only in non-weatherized units, which are a very small portion of the CWAF market. DOE was not able to find any studies published on the thermal efficiency benefits of concentric venting of CWAF. Due to the scarcity of non-weatherized installations in the CWAF market, there is also limited potential for improving the nation-wide efficiency of CWAF, since weatherized installations are the largest segment of the market.

4.6 REMAINING TECHNOLOGY OPTIONS

After eliminating certain technology options from consideration, the technologies that were not eliminated (listed in Table 4.6.1) were evaluated further in the subsequent engineering analysis.

Table 4.6.1 Technology Options for CWAF Passed Through to the Engineering Analysis

Addition of condensing, secondary heat exchanger
Increased heat exchanger surface area
Incorporation of heat exchanger surface enhancements (such as dimples) and internal enhancements such as baffles and turbulators
Concentric venting
High-static flame-retention head oil burner (oil-fired CWAF only)

CHAPTER 5. ENGINEERING ANALYSIS

TABLE OF CONTENTS

5.1 INTRODUCTION 5-1
5.2 METHODOLOGY OVERVIEW 5-1
5.3 EQUIPMENT CLASSES ANALYZED 5-3
5.4 REPRESENTATIVE CAPACITIES 5-3
5.5 EFFICIENCY LEVELS 5-3
5.5.1 Baseline Units 5-4
5.5.2 Intermediate Energy Efficiency Levels 5-4
5.5.3 Max-tech Efficiency Levels 5-4
5.5.4 Overview of Efficiency Levels of CWAF and Common Technologies Used at Each Efficiency Level 5-5
5.6 TEARDOWN ANALYSIS 5-10
5.6.1 Selection of Units 5-11
5.6.2 Description of Teardown Analysis 5-12
5.7 COST MODEL 5-15
5.7.1 Generation of Bills of Materials 5-15
5.7.2 Cost Structure of the Spreadsheet Models 5-16
5.7.3 Cost Model Definitions 5-16
5.7.3.1 Cost Definitions 5-17
5.7.4 Cost Model Estimates Overview 5-17
5.7.4.1 Fabrication Estimates 5-18
5.7.4.2 Production Volume Estimations 5-18
5.7.4.3 Factory Parameters Estimations 5-19
5.7.4.4 Material Price Estimations 5-20
5.7.5 Manufacturing Production Cost 5-20
5.8 COST VERSUS EFFICIENCY CURVES 5-21
5.9 MANUFACTURER MARKUP 5-24
5.9.1 Manufacturer Selling Price 5-24
5.9.2 Manufacturer Markup 5-24
5.9.3 Shipping Costs 5-25
5.10 ENGINEERING ANALYSIS SUMMARY OF RESULTS 5-27
5.10.1 Summary of Results for Representative Models 5-27

LIST OF TABLES

Table 5.3.1 CWAF Equipment Classes 5-3
Table 5.4.1 Representative CWAF Equipment for Analysis 5-3
Table 5.5.1 Thermal Efficiency Levels analyzed for CWAF 5-5
Table 5.7.1 Major Manufacturing Processes for CWAF 5-18

Table 5.7.2 Gas-Fired CWAF Factory Parameter Estimations 5-19
Table 5.7.3 Oil-Fired CWAF Factory Parameter Estimations..... 5-19
Table 5.7.4 Material Prices 5-20
Table 5.8.1 Breakdown of Heat Exchanger Material Type by Efficiency Level* 5-22
Table 5.9.1 Shipping Dimensions for Gas-Fired CWAF*..... 5-26
Table 5.9.2 Shipping Dimensions for Oil-Fired CWAF..... 5-26
Table 5.9.3 CWAF Shipping Cost Estimates 5-27
Table 5.10.1 MPC and MSP for Gas-Fired CWAF- Aluminized Steel Heat Exchanger and Inducer Assembly Components at 80% TE, 81% TE, and 82% TE..... 5-27
Table 5.10.2 MPC and MSP for Gas-Fired CWAF- SS409 Heat Exchanger and Inducer Assembly Components at 80% TE, 81% TE, and 82% TE 5-27
Table 5.10.3 MPC and MSP for Gas-Fired CWAF- SS316 Heat Exchanger and Inducer Assembly Components at 80% TE, 81% TE, and 82% TE 5-28
Table 5.10.4 MPC and MSP for Oil-Fired CWAF 5-28

LIST OF FIGURES

Figure 5.2.1 Flow Diagram of Engineering Analysis Methodology 5-2
Figure 5.7.1 A General Breakdown of Costs Associated with Manufacturing a CWAF 5-21
Figure 5.8.1 MPC versus Thermal Efficiency for Gas-Fired CWAF 5-22
Figure 5.8.2 MPC versus Thermal Efficiency for Oil-Fired CWAF 5-23

CHAPTER 5. ENGINEERING ANALYSIS

5.1 INTRODUCTION

The engineering analysis establishes the relationship between the manufacturer selling price (MSP) and the energy efficiency of Commercial Warm Air Furnaces (CWAF). The relationship between the MSP and energy efficiency, or the cost-efficiency relationship, serves as the basis for cost-benefit calculations in terms of individual customers, manufacturers, and the Nation.

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 equipment 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 CWAF using the reverse engineering approach to determine the manufacturing costs of CWAF at different thermal efficiency (TE) levels.

5.2 METHODOLOGY OVERVIEW

This section describes the analytical methodology used in the engineering analysis. Figure 5.2.1 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 equipment class.

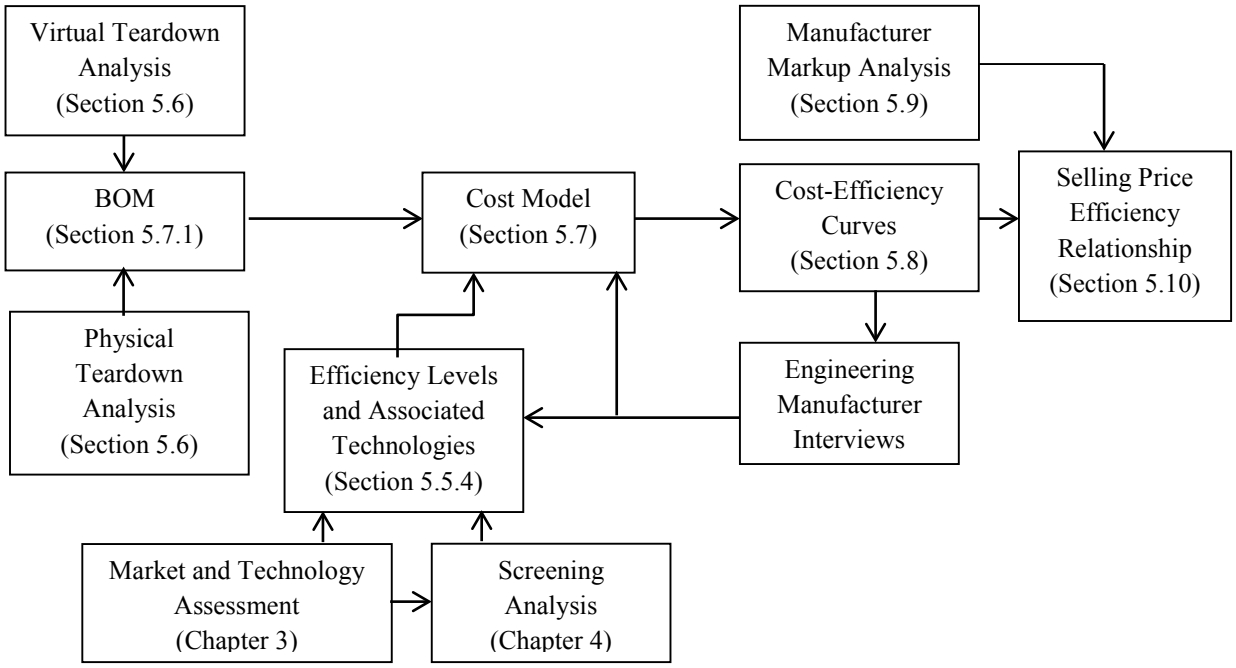


Figure 5.2.1 Flow Diagram of Engineering Analysis Methodology

DOE started by identifying CWAF available on the market and the energy efficiency level associated with each model. DOE then separated the models based on whether or not they operated at the minimum standard efficiency level, above the minimum standard efficiency level but at a non-condensing efficiency level, or at a condensing efficiency level. Next, DOE identified the technologies and features typically incorporated into equipment at the baseline level and the various energy efficiency levels above the baseline.

For the CWAF, DOE gathered information from both virtual and physical teardowns to create bills of materials (BOMs) for each unit torn down using reverse engineering methods (see section 5.6), and to confirm the technology options that manufacturers use to increase the TE of CWAF. DOE converted the information recorded in the BOMs to dollar values to calculate the manufacturing production cost (MPC) for equipment spanning the full range of efficiencies from the baseline to the maximum technologically feasible ("max-tech") level. DOE also identified the technology or combination of technologies mainly responsible for improving the energy efficiency of CWAF across this range.

During the development of the cost-efficiency curves, DOE interviewed manufacturers to gain insight into the CWAF industry and requested comments on the engineering approach DOE used for the analysis. DOE used the information gathered from these interviews to refine the technology options implemented at each efficiency level, as well as any estimations made in the cost model. Next, DOE converted the MPCs into MSPs using a manufacturer markup (section 5.9), which is calculated using publicly available industry financial data, along with manufacturer feedback.

5.3 EQUIPMENT CLASSES ANALYZED

DOE divides covered equipment into classes by: (a) the type of energy used; (b) the capacity; or (c) any performance-related features that affect customer utility or efficiency. (42 U.S.C. 6295(q)) Different energy efficiency standards may apply to different equipment classes.

Table 5.3.1 shows the CWAF equipment classes considered for this rulemaking.

Table 5.3.1 CWAF Equipment Classes

Equipment Type	Heating Capacity (Btu/h)
Gas-fired	≥225,000 Btu/h
Oil-fired	≥225,000 Btu/h

5.4 REPRESENTATIVE CAPACITIES

Within both equipment classes, CWAF span a wide range of heating input capacities. This variation in capacity also can cause wide variations in equipment prices and energy use. Thus, DOE selected a representative heating input capacity for each equipment class at which an analysis was conducted. Using a representative capacity allowed DOE to analyze specific equipment in detail that can provide information representative of the entire equipment class. DOE analyzed the database it compiled in the market and technology assessment and discussions with manufacturers to determine an appropriate representative heating input capacity for each equipment class, as shown in Table 5.4.1 below.

Table 5.4.1 Representative CWAF Equipment for Analysis

Equipment Type	Representative Heating Input Capacity (Btu/h)
Gas-fired	250,000 Btu/h
Oil-fired	250,000 Btu/h

DOE used these representative heating input capacities as the basis for the rest of the engineering analysis and the cost-efficiency curves. In the engineering analysis, DOE gathered information regarding models with heating input capacities as close to the representative equipment size as possible.

5.5 EFFICIENCY LEVELS

DOE analyzed equipment at multiple TE levels for each equipment class as close as possible to the representative equipment capacities presented in section 5.4 and estimated the MPCs at each efficiency level analyzed. The following subsections provide a description of the full efficiency range from the baseline to max-tech efficiency level for both equipment classes. DOE identified the max-tech efficiency level by reviewing product literature for commercially available equipment and information obtained during interviews with manufacturers.

5.5.1 Baseline Units

DOE selected baseline units as reference points for each equipment class, against which changes resulting from potential amended energy conservation standards could be measured. The baseline unit in each equipment class displays the basic characteristics of equipment in that class. A baseline unit is a unit that just meets and does not exceed current Federal energy conservation standards and provides basic customer 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 use of the baseline unit. Similarly, to determine the changes in price to the customer 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.

The identification of baseline units requires establishing the baseline efficiency level. For all equipment classes, DOE defined the baseline efficiency level as the efficiency level equal to the current Federal energy conservation standard. The baseline efficiency levels for each equipment class are shown in Table 5.5.1.

5.5.2 Intermediate Energy Efficiency Levels

As discussed in detail in chapter 3 of this TSD (Market and Technology Assessment), DOE compiled a database of the CWAF market to determine what types of equipment are currently available to customers. At the representative capacity, DOE surveyed various manufacturers' equipment offerings to identify commonly-available efficiency levels and the technologies used to achieve each efficiency level. By identifying the most prevalent energy efficiencies in the range of available equipment, DOE established a technology path that manufacturers typically use to increase the TE of a CWAF, and corresponding efficiency levels along that technology path.

DOE established intermediate TE levels for each equipment class. The intermediate TE levels are representative of efficiency levels along the technology paths that manufacturers of CWAF commonly use to maintain cost-effective designs while increasing TE. DOE reviewed the database of CWAF it compiled, which included data from the DOE's Compliance Certification Management System (CCMS),[1] manufacturer catalogs, and other publicly available literature to determine which TE levels are the most prevalent for each representative equipment class. For gas-fired CWAF, DOE chose two efficiency level between the baseline and max-tech for analysis. For oil-fired CWAF, DOE chose one efficiency level between the baseline and max-tech for analysis.

5.5.3 Max-tech Efficiency Levels

As part of the engineering analysis, DOE determined the maximum technologically feasible improvement in energy efficiency for CWAF as required by EPCA. (42 U.S.C. 6313(a)(6)(A)(ii)(II)) DOE conducted a survey of its CWAF database, manufacturers' websites,

and technical literature to determine the highest efficiency a CWAF in each equipment class can attain. DOE also discussed the appropriate max-tech level for each equipment class with manufacturers during interviews.

As discussed in the DFR, the definition of a CWAF requires that (among other criteria) a unit be able to "supply heated air through ducts to spaces that require it" (42 U.S.C. 6311(11)(A)). Therefore, if a makeup air furnace is capable of operating in this manner, and if it meets all other criteria to be classified as a CWAF, then it would be considered as such under DOE's regulations. In the market assessment, DOE identified gas-fired makeup air CWAF with an efficiency of 92% TE, which is a higher efficiency than any of the other gas-fired units identified. As such, DOE considers 92% TE to be the max-tech efficiency level for gas-fired CWAF in this analysis.

For both CWAF equipment classes, DOE is not aware of any working products or prototypes currently available at a higher efficiency than the max-tech level. The max-tech levels DOE determined for each CWAF equipment class are shown in Table 5.5.1.

5.5.4 Overview of Efficiency Levels of CWAF and Common Technologies Used at Each Efficiency Level

DOE selected the efficiency levels for analysis as shown in Table 5.5.1.

Table 5.5.1 Thermal Efficiency Levels analyzed for CWAF

Efficiency Level	Gas-Fired CWAF	Oil-Fired CWAF
Baseline	80%	81%
EL1	81%	82%
EL2	82%	
Max-Tech	92%	92%

To determine the common technology options manufacturers use to achieve each efficiency level above baseline, DOE reviewed manufacturers' equipment literature and conducted physical and virtual teardowns for market-representative models found at these efficiency levels. DOE also discussed with manufacturers the technologies that are typically implemented at each efficiency level. DOE found that in order to maintain retrofit ability and standardize manufacturing across product lines, manufacturers commonly structure equipment designs around specific cabinet sizes. Once a particular design requires components that become too large for a given cabinet, manufacturers move to a larger cabinet size, which increases manufacturing cost.

<u>Gas-fired CWAF</u>

80% to 81% TE

Manufacturers typically increase the efficiency of gas-fired CWAF from 80% to 81% by increasing the heat exchanger surface area. Based on feedback from manufacturer interviews, DOE estimates that the heat exchanger surface area must be increased by 10% to increase TE by

1%. In addition, during the May 11, 2015 Appliance Standards and Rulemaking Federal Advisory Committee (ASRAC) meeting for this rule, manufacturers stated that to increase efficiency above baseline, heat exchanger size would be increased by adding tubes to the heat exchanger, but not by lengthening the heat exchanger tubes. Therefore, to estimate the cost of increasing efficiency from 80% TE to 81% TE, DOE accounted for adding heat exchanger tubes in order to increase the size of the heat exchanger by 10%.

During the May 11, 2015 ASRAC meeting, manufacturer feedback also indicated that the increase in heat exchanger surface area at 81% TE would not be expected to increase the unit's cabinet size. One reason for this could be because gas-fired CWAF are typically packaged with commercial package air conditioner systems (referred to as 'CUAC') which generally drive the required size of the cabinet. The units that DOE examined for physical teardown had sufficient room to add heat exchanger tubes to a baseline-size heat exchanger in order to achieve 81% TE, without requiring increases to surrounding cabinet dimensions beyond the dimensions already required to accommodate a CUAC. Therefore, DOE determined that adding heat exchanger tubes to increase the heat exchanger size by 10% would not require manufacturers to increase the size of the cabinet to accommodate a larger heat exchanger.

During manufacturer interviews, some manufacturers suggested that increasing the size of the heat exchanger may necessitate a larger indoor air blower fan motor at efficiency levels higher than baseline, in order to compensate for an increase in static pressure drop in the indoor airflow path caused by enlargement of the heat exchanger. Through discussions with industry experts and a review of product literature, DOE determined that these fans are typically sized based on the requirements of a building's ducting and the demands of the air-conditioning system, and their size does not depend on the required heat exchange size at different efficiency levels. This determination was supported by an examination of product literature in which DOE found multiple examples of CWAF with the exact same heating input capacity and efficiency but different size blower motors, indicating that blower motor size often varies independent of the efficiency of a unit. DOE also examined data from analyses of residential furnaces and found that manufacturers produce many models of the same capacity but of varying efficiency levels, and these models use the same blower motors (*i.e.*, the blower motor size generally was not increased to compensate for the enlargement of the heat exchanger at higher efficiency levels). These findings in both CWAF and residential furnace product literature demonstrate that blower motor size in furnaces is governed by variables other than heating capacity and efficiency. Therefore, DOE assumes that given the range of other variables that impact the size of the blower fan motor, increasing the efficiency would not directly necessitate a larger blower fan motor.

Manufacturers also suggested that a higher efficiency CWAF may need a larger inducer fan motor. DOE understands that the increased flue side pressure drop resulting from a larger heat exchanger will require an increase in inducer fan output. However, based on the units that DOE examined, it appears that the inducer fan motors used in baseline units generally provide more than enough power and could allow for the required increase in inducer fan output to compensate for the increased flue side pressure drop in higher efficiency units at 81% TE and 82% TE. For example, during teardowns DOE observed the use of restrictor plates in front of inducer blowers and/or combustion chamber intakes, to restrict the airflow through the heat

exchanger. DOE determined that if manufactures need to increase the output of an inducer fan to adjust for the increased flue side pressure drop caused by a larger heat exchanger, they will keep the same size inducer motor, but make the restrictor plates less restrictive. This technique allows manufacturers to use the same motor across a range of products.

Aluminized steel is the most commonly used material for heat exchangers in 80 and 81% TE CWAF, although manufacturers offer stainless steel heat exchangers as an option. This is because under certain conditions, the furnace's products of combustion can begin to condense slightly at these levels, which produces low concentrations of acidic condensate inside the heat exchanger. Over time, production of this condensate can corrode the heat exchanger, leading to a premature product replacement. Stainless steel has a higher resistance to condensate than aluminized steel. Manufacturer feedback and research of product literature indicated that 409 grade stainless steel (SS409) and 316 grade stainless steel (SS316) are often offered as optional heat exchanger materials in both 80% and 81% TE CWAF. In the engineering analysis, DOE estimated separate the costs for 80% and 81% TE CWAF with heat exchangers constructed of aluminized steel, SS409, and SS316., These cost estimates were then used as inputs to the LCC/PBP analysis (see chapter 8 of the TSD).

80% to 82% TE

As explained in the description of the cost estimation for achieving the 81% TE efficiency level, DOE estimated that the heat exchanger surface area must be increased by 10% to increase TE by 1%. As a result, in order to increase efficiency from 80% TE to 82% TE, total heat exchanger surface area must be increased by 10% to achieve 81% TE, and then by 10% again (or 21% in total, relative to 80% TE) to achieve 82% TE. As also described previously, manufacturer feedback indicated that this increase in heat exchanger surface area is performed by increasing the number of heat exchanger tubes. Therefore, DOE estimated the cost of 82% TE CWAF by accounting for adding heat exchanger tubes to increase the total heat exchanger surface area by 21%.

Manufacturer feedback indicated that condensation of combustion products has a significant likelihood of occurring at efficiencies greater than or equal to 82% TE.To maintain reliability and prevent premature equipment replacement at 82% TE, manufacturers stated that most gas-fired CWAF would require substantial design changes to account for the potential formation of corrosive condensate in the heat exchanger. As such, components of the heat exchanger and inducer assemblies that make contact with the products of combustion in most 82% TE CWAF should be constructed from a corrosion resistant material in order to minimize degradation of these components over time due to condensate formation. Manufacturer feedback indicated that SS316 provides the minimum acceptable level of corrosion resistance to the level of acidic condensate formation which occurs in most gas-fired CWAF at 82% TE. As such, in its cost estimates for these units, DOE incorporated the usage of SS316 for components of the heat exchanger and inducer assemblies that come into contact with combustion products. DOE also estimated the cost of units that would incorporate SS409 as the material for heat exchanger and inducer assembly components that come into contact with the products of combustion, as DOE believes that in certain applications a lower grade of stainless steel would provide an acceptable

level of corrosion resistance. These costs served as inputs to the LCC/PBB analysis (see chapter 8).

80% to 92% TE

In order to increase the efficiency of a gas-fired CWAF from 80% to 92% TE, manufacturers must design the CWAF with a condensing heat exchanger capable of capturing the latent heat of combustion products. Manufacturers generally accomplish this by using two heat exchangers, a primary heat exchanger which is made of aluminized steel and a secondary heat exchanger made of a highly durable stainless steel material (typically AL 29-4C). The primary heat exchanger is sized to limit the amount of heat transfer that occurs inside it, such that condensation of combustion products does not occur. The flue gases exit the primary heat exchanger into a header from which they are then redistributed into the secondary (condensing) heat exchanger. The space within the cabinet of combined CWAF/CUAC units observed during teardowns cannot accommodate a secondary heat exchanger, so DOE determined that the cabinet for units at 92% TE must be enlarged relative to gas-fired CWAF at lower efficiencies. DOE accounted for the costs associated with a larger cabinet (such as increased size of jacket panels and insulation) in the estimation of the production costs for the max-tech efficiency level. The secondary heat exchanger creates enough flue side pressure drop that DOE determined the size of the combustion inducer fan would need to be increased, and accounted for this impact in the analysis based on observations made from examining a commercial rooftop system with a condensing furnace section. However, for the same reasons described above in the discussion of the 81% TE level, DOE determined that an increase in the size of the indoor blower fan would not be necessary to overcome the additional pressure drop in the circulating air stream caused by the condensing heat exchanger section.

Inside the secondary heat exchanger, acidic condensate forms as latent heat is extracted from the products of combustion. This condensate is a solution of water and acids, containing carbonic acid (H_2CO_3), sulfuric acid (H_2SO_4), and hydrochloric acid (HCl). The pH of the condensate is usually around 4 for gas-fired appliances and can be as low as 2 for oil-fired appliances. The pH of the condensate drives the use of highly durable stainless steel (AL 29-4C) in the secondary heat exchanger.

Condensate management is a key issue due to the acidity of the condensate as well as the typical installation locations of gas-fired CWAF. Because gas-fired CWAF are typically installated on a roof, the condensate cannot be easily neutralized and then directed to an existing floor drain, as is the case for non-weatherized furnaces. Instead, the manufacturer has to make accommodations to ensure that the acidic condensate can be safely and consistently captured and drained from the unit so that it cannot cause damage to the unit or the building it is installed on. Every CWAF unit that DOE inspected was specified to drain its condensate inside the building envelope, which raises installation costs. (See chapter 8 of the TSD for information regarding installation costs.)

From manufacturer interviews, DOE gathered that many municipalities now require the neutralization of condensate to help prevent accelerated deterioration of cast-iron sewer pipes.

Condensate can be neutralized by directing it through a plastic container filled with limestone chips. Replacing the dissolved chips is part of the annual maintenance for such equipment.

DOE purchased a gas-fired, weatherized, condensing rooftop HVAC system, rated at 92% TE for physical examination. This unit was designed with a primary and secondary heat exchanger, as described above, and is intended to be installed with the condensate drained through the interior of the building. DOE used the knowledge gained from analyzing this unit to inform its cost estimations for the 92% TE efficiency level. In addition, DOE purchased and tore down a residential weatherized furnace with an efficiency of 95% AFUE, which was also used to inform DOE's estimations for the analysis of the max-tech level for gas-fired CWAF.

Oil-fired CWAF

Oil-fired CWAF are typically constructed differently from gas-fired units. For example, gas-fired units are typically installed in a package with a CUAC and are weatherized, whereas oil-fired units are solitary systems (i.e., not installed with a cooling section), and are non-weatherized. The primary heat exchangers in oil-fired CWAF are typically drum-shaped and are assembled from thick sheets of steel that have been cut, formed, and welded. Unlike gas-fired CWAF, oil-fired units rely on positive pressure combustion systems that use interchangeable chassis oil burners. These chassis burners are an integrated system consisting of an oil pump, a blower, and an ignition system.

Manufacturers of oil-fired CWAF equipment usually give their customers several options regarding the specific oil burners that can be used, including specific details like recommended pump pressure, nozzle type, air shutter settings, etc. During operation, the oil pump inside the chassis burner pulls oil from the oil tank, through a filter, and pressurizes it. Meanwhile, the blower produces a strong air flow past an oil nozzle and a set of turbulator blades that are designed to produce a very fine mist of oil that is ignited using a pair of spark electrodes. An optical cell ensures that a flame is produced, and if not, shuts down the pump and blower.

81% to 82% TE

Manufacturers of oil-fired CWAF primarily increase efficiency from 81% to 82% TE by increasing the size of the heat exchanger in the unit. Based on feedback gathered from interviews with manufacturers, DOE estimates that the heat exchanger surface area must be increased by 10% to achieve this efficiency improvement. Based on physical teardown of an 81% TE oil-fired CWAF, DOE observed that the cabinet typically does not have room to accommodate such growth in the heat exchanger. Unlike most gas-fired CWAF, oil-fired CWAF are not packaged with air conditioning components, so the jacket dimensions are more sensitive to the size of the internal furnace components. As such, DOE determined that the size of the cabinet must be increased to accommodate the larger heat exchanger necessary to achieve 82% TE. Similar to gas-fired CWAF (and as discussed previously), an upgrade of blower motors or inducer motors is unnecessary when increasing the TE of an oil-fired CWAF one percent above baseline efficiency. As with gas-fired CWAF, the typical heat exchanger found in 81% and 82% TE oil-fired CWAF is made of aluminized steel, and is typically thicker than the thickness used for gas-

fired CWAF. The heat exchanger is sometimes constructed from more expensive stainless steel instead of aluminized steel, in order to provide improved durability.

81% to 92% TE

In order to raise the efficiency of an oil-fired CWAF from 81% to 92% TE, a secondary heat exchanger is incorporated into the furnace design. The secondary heat exchanger allows for the extraction of a significant additional amount of useful heat from the products of combustion, as compared to the amount of heat extracted at the baseline efficiency level. As the products of combustion pass through the secondary heat exchanger, they cool below their dew point and cause an acidic condensate to accumulate in the heat exchanger. Manufacturers of condensing, oil-fired CWAF currently build secondary heat exchangers using AL 29-4C, which is a high grade, corrosion resistant stainless steel with sufficient corrosion resistance to withstand the amount of acidic condensate produced at 92% TE. The secondary heat exchanger is located upstream of the primary heat exchanger in the indoor air stream (i.e. in the direction of the return air inlet) to maximize heat transfer.

The secondary heat exchanger provides a substantial increase in heat transfer area to the building supply air stream. The additional heat exchanger necessitates changes in other parts of the furnace in order to maintain the same level of performance as a baseline unit. The higher static pressure drop that results from the addition of a secondary heat exchanger reduces the number of burner chassis' that can be used on such a system. However, there are multiple burner chassis on the market that are made for high static pressure applications. Cabinets for condensing oil-fired CWAF tend to be larger than those for non-condensing types in order to accommodate the addition of the secondary heat exchanger, which occupies significant volume. Also, condensing oil-fired CWAF require the incorporation of a condensate management system to capture, redirect, and (depending on installation location) neutralize the acidic condensate produced during operation.

5.6 TEARDOWN ANALYSIS

To assemble BOMs and calculate the manufacturing costs of the different components in CWAF at each efficiency level analyzed, DOE first tested several CWAF at different efficiencies according to the DOE test procedure, and then disassembled those units into their source components and estimated the material, labor, depreciation, and overhead costs attributable to each component. This process is referred to as a "physical teardown", which starts with a unit as-shipped (*e.g.*, boxed, crated, on a pallet, etc.) and ends with all components having been disassembled and entered into the BOM.

A supplementary method, called a "virtual teardown," uses physical examinations of units, published manufacturer catalogs, and/or supplementary component data to estimate the manufacturing cost of a unit that was not physically torn down by noting the stated differences between it and a unit that was torn down. Usually, such virtual teardowns are used to estimate the costs of units with minor differences from the unit that was torn down, such as different input capacities, different blower motors, and so on. Components such as sheet metal, unit wiring, and packaging scale with unit dimensions.

The teardown analysis included a total of 3 physical teardowns and 7 virtual teardowns of CWAF.

5.6.1 Selection of Units

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

- What efficiency levels should be captured in the teardown analysis?
- Are there model lines on the market that capture all potential efficiency levels?
- Which of the available units are most representative of the marketplace?

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

- The selected equipment should span the full range of efficiency levels for each equipment class under consideration.
- If possible, the selected models within each equipment class should come from the same manufacturer and be within the same product series.
- The selected models should come primarily from manufacturers with large market share in that equipment class, although the highest efficiency models were chosen irrespective of manufacturer.
- The selected models should have non-efficiency related features that are the same or similar to features of other models in the same equipment class and for a range of efficiency levels.

DOE reviewed the CWAF industry and identified models available to customers. DOE then applied the aforementioned criteria and selected baseline, intermediate, and max-tech efficiency units that met the equipment descriptions, energy efficiency levels, and included the common technology options identified during the market review and discussions with manufacturers. In several cases, DOE conducted a virtual teardown to estimate the cost of a unit, rather than conduct a physical teardown.

Using the data gathered from the physical teardowns, DOE characterized each component according to its weight, dimensions, material, quantity, and the manufacturing processes used to fabricate and assemble it. For supplementary virtual teardowns, DOE gathered product data such as dimensions, weight, and design features from publicly available manufacturer catalogs, installation manuals, or engineering specifications. DOE obtained information and data not typically found in catalogs and brochures from the physical teardowns of similar equipment or by estimations based on industry knowledge. DOE collected additional component information during the manufacturer interviews.

Characteristics of units selected for physical and virtual teardowns are discussed in the sections that follow. DOE does not identify the model number or manufacturer of the units examined during the teardown analysis because this could expose sensitive information about individual manufacturers' equipment.

5.6.2 Description of Teardown Analysis

For the gas-fired CWAF analysis, DOE selected 2 weatherized models for physical teardown, both with a heating capacity of 250,000 Btu/h. Both of these units were packaged with CUAC systems. Prior to teardown, DOE tested the TE of both of these units in accordance with the DOE test procedure, and they both tested at 82% TE. DOE also performed 4 virtual teardowns; 2 of 80% TE, and 2 of 81% TE, 250,000 Btu/h input, weatherized models based on information collected from each of the 2 physical teardowns. As described previously, in performing these virtual teardowns, DOE was able to use determinations developed based on manufacturer feedback to estimate the differences between units at 80%, 81%, and 82% TE.

Additionally (and as previously discussed in section 5.5.4), DOE purchased a weatherized, condensing, 92% TE gas-fired makeup air CWAF for physical examination. This unit had a heating input capacity of 260,000 Btu/h and an efficiency rating of 92% TE. DOE used a virtual teardown to scale down this unit and estimate the cost of a similar unit at the representative 250,000 Btu/h heating input capacity.

For the oil-fired CWAF analysis, DOE selected an 81% TE non-weatherized unit with a heating capacity of 400,000 Btu/h for physical teardown, and subsequently scaled down the size of components with dimensions that are dependent on heating input capacity, in order to model a unit at the representative capacity of 250,000 Btu/h. Additionally, DOE performed 2 virtual teardowns of both 82% TE and 92% TE, 250,000 Btu/h heating capacity, non-weatherized models. These virtual teardowns were conducted based on information gathered from the physical teardown of the 81% TE unit, as well as data gathered from the residential furnaces rulemaking. As discussed previously, in performing these virtual teardowns, DOE was able to use analytical inputs developed based on manufacturer feedback to estimate the differences between units at 81%, 82%, and 92% TE.

For the virtual teardowns performed for both gas-fired and oil-fired CWAF, DOE used physical teardowns of similar or comparable units to the units being virtually torn down, and refined them with data gathered from manufacturer interviews, product literature, physical examinations, information gathered from engineering analyses in similar rulemakings, and consultations with manufacturing experts. As described above, DOE conducted virtual teardowns of 5 gas-fired units, and virtual teardowns of 2 oil-fired units. The methods used to conduct each of the virtual teardowns are described below.

<u>Gas-fired CWAFs</u>

As mentioned previously, DOE tested the TE of, and then physically tore down 2 weatherized gas-fired CWAF which were packaged with CUAC systems. These units were sold as 80% and 82% TE, respectively, though the test results for these units were nearly identical at approximately 82%, with the unit that was sold as 80% TE testing at a slightly higher efficiency than the unit sold as 82% TE.

Upon physical examination, DOE noted that the two non-condensing gas-fired CWAF featured identical gas trains, heat exchangers, air-paths, and other physical characteristics that would influence TE. The only difference between the two units was the use of a slightly larger indoor-fan motor on the unit that was sold as 80% TE. Thus, it is logical that the two units had nearly identical test results – the unit with the larger indoor air fan motor tested very slightly above that of the other unit. DOE research suggests that the difference in stated TE between the two units is most likely related to differentiation of the equipment's intended standard operating conditions by the manufacturer (which could in part be attributed to differences in the intended standard operating conditions of each of the CUAC systems that each CWAF unit was packaged with).

To estimate the manufacturing costs for gas-fired CWAF at 82% TE, DOE used the estimated manufacturing costs of both units torn down as the basis for its calculations. As discussed in section 5.5.4, DOE estimated the manufacturing costs at 82% TE both for units using SS316 and units using SS409 for certain heat exchanger and inducer assembly components. In the two units torn down, the heat exchanger and inducer assemblies were constructed out of aluminized steel, so the costs of these specific units could not be directly used to develop the cost estimates for 82% TE. Using raw material price comparisons and knowledge of the manufacturing processes used to fabricate finished components from a variety of raw materials, DOE modified its cost estimates for both the heat exchanger and inducer assemblies of the units torn down to account for the costs of using either SS316 or SS409, rather than aluminized steel, for certain components. These modified cost estimates of both units torn down were then averaged together for each of the two material options modeled, to develop two final estimated costs accounting for the usage of either SS316 or SS409 in 82% TE gas-fired CWAF.

In accordance with manufacturer guidance (and as described previously in section 5.5.4), DOE performed virtual teardowns to scale down the sizes of the heat exchangers of each of the two 82% TE units torn down, to estimate the costs of both 81% and 80% TE units. As was discussed in section 5.5.4, DOE estimated that manufacturers would need to increase the heat exchanger surface area of baseline CWAF by 10% in order to achieve 81% TE, and increase it by another 10% to achieve 82% TE. As also discussed in section 5.5.4, manufacturer feedback indicated that heat exchanger tubes would be added to the heat exchanger in order to increase heat exchanger surface area. Accordingly, in order to estimate the heat exchanger size at 81% TE, the size of the heat exchanger in each 82% TE unit was decreased 10% by removing heat exchanger tubes. In order to estimate the heat exchanger size at 80% TE, the size of the heat exchanger at 81% TE was further decreased by 10% by removing heat exchanger tubes. As noted previously, the heat exchangers in the two units torn down were constructed out of aluminized steel. As was discussed in section 5.5.4, DOE estimated the manufacturing costs at 80% and 81% TE not just for units using aluminized steel, but also for units using SS316 and units using SS409 for certain heat exchanger and inducer assembly components. Using raw material price comparisons and knowledge of the manufacturing processes used to fabricate finished components from a variety of raw materials, DOE developed additional cost estimates for both the heat exchanger and inducer assemblies of units at 80% and 81% TE to account for the costs of using either SS316 or SS409 for certain components. Finally, the cost estimates of the virtually torn down units were then averaged together for each of the three material options modeled (aluminized steel, SS409, and SS316) to develop three final estimated costs for both the

80% and 81% TE efficiency levels, representing the costs of using either aluminized steel, SS409 or SS316 at either the 80% or 81% TE efficiency levels.

The virtual teardown based on a physical examination of the condensing, 92% TE gas-fired CWAF, was also based in part on the physical teardowns of 82% TE models. DOE purchased the 92% TE unit in order to gain insight into the manufacturing practices and implementation of a secondary heat-exchanger in a gas-fired CWAF, as well as the condensate disposal system required for a weatherized, condensing, gas-fired CWAF. During physical examination, DOE noted the number of heat exchangers, how they were integrated into the unit, wall thicknesses, and material choices, among other factors, to determine the likely cost of adding a secondary heat exchanger into the airstream of a gas-fired CWAF with a design similar to the non-condensing units that were torn down. As noted in section 5.5.4, DOE also performed a physical teardown on a residential condensing weatherized furnace that provided further information for DOE's estimate of the MPC at the max-tech level.

DOE research suggests that neither of the two 82% TE units torn down would have been able to accommodate a secondary heat exchanger without significant modifications. DOE has observed that secondary heat exchangers are placed upstream of the primary heat exchangers in the indoor circulation airstream (i.e. in the direction of the return air inlet) to maximize heat transfer, and the units torn down did not have room to accommodate a secondary heat exchanger. To accommodate the added volume needed for the secondary heat exchanger assembly, DOE scaled the enclosure to be more than a foot taller than the original unit. Additionally, DOE added more packaging, insulation, sheet metal, extended wiring, and fasteners inside the unit to accommodate the new configuration.

DOE estimated the production cost of the secondary heat exchanger on the basis of physical examination of the 92% unit, and on feedback from manufacturer interviews. Specifically, DOE used the physical examination to determine the physical dimensions, quantity of components, assembly methods, and use of AL 29-4C in the secondary heat exchanger. Additionally, DOE accounted for the production cost of corrosion resistant heat exchanger headers, a corrosion resistant inducer assembly, and a condensate collection system, while also doubling the inducer fan power to account for the greater flue side pressure drop impinged by the implementation of a secondary heat exchanger. DOE research suggests that the 92% TE unit is produced in very low numbers, so some of its physical features would not be found on units produced in high volumes (*i.e.*, which would result from a standard being set at 92% TE and all production volume shifting to that level). For example, the 92% unit features some hand-welded assemblies that higher-volume manufacturers would either stamp out of one piece of sheet metal or mold using a high-temperature thermoplastic. DOE estimated the manufacturing costs for the 92% TE unit on the basis of a standards case by using the high-volume manufacturing techniques observed in other units as an input to these estimations.

<u>Oil-fired CWAF</u>

DOE performed a physical teardown of oil-fired CWAF at 81% TE, and virtual teardowns at 82% and 92% TE. The 81% physical teardown was performed on a unit with a heating capacity of 400,000 Btu/h. In order to scale down this model to represent a unit of

250,000 Btu/h representative input heating capacity, DOE adjusted the size of the heat exchanger, sheet metal components, insulation, packaging materials, and other miscellaneous components based on scaling factors. DOE developed these scaling factors from the relationship of heat exchanger volumetric size versus heating input for oil-fired CWAF. After scaling down the 81% TE unit, the 82% TE and 92% TE units were modeled off of the 81% TE unit. The burner chassis used in the 81% TE unit offered a firing rate of 1- 3.5 gallons per hour (i.e. ~120-450kBTU/h), so this component sufficiently maintained the same level of operability in all of the 81% TE, 82% TE and 92% TE units, and was used in all three teardowns.

As stated in section 5.5.4, DOE determined that in order to increase the efficiency of an oil-fired CWAF from 81% TE to 82% TE, manufacturers increase the surface area of the heat exchanger by 10%. Cabinet sizes of oil-fired CWAF vary with the size of the heat exchanger, which is the largest component of the furnace. As such, DOE scaled the size of the cabinet, other sheet metal components such as mounting brackets, insulation, and packing materials to increase in size in proportion with the expansion of the heat exchanger from the 81% TE to the 82% TE unit. DOE did not adjust the size of the inducer motor, blower motor, or fans when modeling the 82% TE unit because, as stated in section 5.5.4, the 10% growth in heat exchanger volume causes negligible increases in both the flue-side and indoor air circulation static pressures.

In order to estimate the cost of the 92% TE unit, DOE used prior information from the residential furnaces rulemaking to understand the necessary sizing of the secondary heat exchanger implemented at this efficiency level, in proportion with the primary heat exchanger used at the 81% TE efficiency level, in order to achieve 92% TE. DOE sized the secondary heat exchanger accordingly, and accounted for the costs of implementing it upstream of the primary heat exchanger in the indoor air circulation path, as discussed in section 5.5.4. To account for the condensate produced in the secondary heat exchanger, DOE also modeled a condensate management system, including PVC pipe for transport of the condensate away from the heat exchanger, and a condensate trap containing limestone rocks for neutralization of the condensate. The addition of a secondary heat exchanger increases static pressure enough to render the indoor blower fan utilized in the 81% TE and 82% TE units of an insufficient size to maintain proper airflow. As such, DOE selected a larger indoor blower fan in the 92% TE model. Additionally, the cabinet, associated sheet metal components, insulation, and packing materials were grown vertically to accommodate the implementation of the secondary heat exchanger above the primary heat exchanger.

5.7 COST MODEL

5.7.1 Generation of Bills of Materials

During teardowns, every layer of the product is peeled back, cataloged, photographed, and examined. The BOM captures every part, every value-added step, and the likely assembly order of components to accurately model the resources required to make a product.

The BOM classifies inputs in multiple ways for later analysis and comparison. For example, the BOM distinguishes between raw materials (*i.e.*, materials that are modified by the

manufacturer from a basic state as part of a fabrication process) and purchased parts which the manufacturer simply assembles into a product. The designations as raw materials or purchased parts were based on DOE's previous industry experience, recent information in trade publications, and discussions with high and low volume original equipment manufacturers (OEMs).

The BOM also categorizes the parts by sub-assembly, allowing comparisons between various suppliers by sub-assembly. Breaking out subassemblies in this manner also allows further analysis, such as the most likely cost for an out-sourced solution versus in-house production. The end result of each teardown is a structured BOM, which describes each equipment part and its relationship to the other parts in the estimated order in which the manufacturer would have assembled them.

The BOMs describe each fabrication and assembly operation in detail, including the type of equipment needed (*e.g.*, presses, injection moldings, 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 price of purchased parts is estimated based on volume-variable price quotations and detailed discussions with manufacturers and component suppliers. For fabricated parts, non-metal raw material prices are based on the most current prices available to DOE. Metal raw material prices are averaged over a 5-year period to reduce the impacts of recent price fluctuations on the estimated MPC (see section 5.7.4.4).

5.7.2 Cost Structure of the Spreadsheet Models

After generating the BOMs from the teardown analysis, the final step is to convert this information into dollar values. DOE collected information on labor rates, tooling costs, raw material prices, and other factors. Although most of the inputs are manufacturer specific and cannot be revealed, section 5.7.4.3 provides a brief discussion of them.

DOE estimated costs of labor, materials, and overhead for 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 contractors typically share cost estimates of purchased parts, raw materials, and assemblies with manufacturers under non-disclosure agreements. Manufacturers provide feedback that is incorporated into the analysis.

5.7.3 Cost Model Definitions

As mentioned in previous sections, the cost model uses a bottom-up approach and divides factory costs into the following categories:

- Materials: Purchased parts (*e.g.*, fan motors, plastics), raw materials (e.g., cold rolled steel), 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.

5.7.3.1 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 part manufacturing.
- Assembly labor: Labor associated with final assembly.
- Indirect labor: Labor associated with the manufacturing facility but which does not directly work on the product, such as fork lift truck drivers, incoming inspection, etc. Indirect labor costs are scaled based on all other labor categories.
- 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 of unit cost.

5.7.4 Cost Model Estimates Overview

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

In converting physical information about the equipment into cost information, DOE reconstructed manufacturing processes for each component using internal expertise and knowledge of the methods used by the industry. DOE used estimations 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 refined its labor cost estimates using information obtained during interviews with CWAF manufacturers. Overhead costs include equipment depreciation, tooling depreciation, building depreciation, utilities, equipment, tooling maintenance, insurance, property, and taxes.

The next sections discuss estimations with regard to outsourcing, factory parameters, production volumes, and material prices. These estimations are presented as industry averages to prevent disclosure of confidential information.

5.7.4.1 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 or from manufacturers themselves during interviews.

DOE based the estimations of manufacturing operations parameters on internal expertise, interviews with manufacturers, and visits to manufacturing facilities. Table 5.7.1 presents the major manufacturer processes identified and developed for the spreadsheet model. Fabrication process cycle times were estimated and entered into the BOM.

Table 5.7.1 Major Manufacturing Processes for CWAF

Fabrication	Finishing	Assembly/Joining	Quality Control
Fixturing	Powder Coating	Adhesive Bonding	Inspection and Testing
Stamping/Pressing	De-Burring	Spot Welding	
Turret Punch	Polishing	Packaging	
Tube Forming		Clinching	
Laser Cutting		Brazing	
Cutting and Shearing		Tig/Mig Welding	
Enameling		Lacing	
Manual Bending		Tube Expansion	
Injection Molding		Evacuation/ Fill	
Vacuum Forming			

5.7.4.2 Production Volume Estimations

Manufacturer production volumes vary depending on several factors, including overall market size, individual company market share, the product or equipment produced, and whether the manufacturer produces other similar products or equipment that utilize the same materials and components. DOE based production volume estimations for CWAF on industry knowledge and information gathered during manufacturer interviews. DOE included in its estimates similar products or equipment that is manufactured by a manufacturer but not within the scope of this rulemaking (*e.g.*, large residential products) in determining its production volume estimations. DOE estimated that a representative factory either produces 40,000 gas-fired CWAFs per year or 2,500 oil-fired CWAFs per year.

5.7.4.3 Factory Parameters Estimations

DOE used information gathered from publicly available literature, manufacturer interviews, and analysis of common industry practices to formulate aggregate factory parameters. DOE first made estimations about a set of factory parameters before the manufacturer interviews, and then revised those estimations based on comments and information gathered during the interviews. Table 5.7.2 lists DOE's estimations for manufacturers of gas-fired CWAF and Table 5.7.3 lists DOE's estimations for manufacturers of oil-fired CWAF.

Table 5.7.2 Gas-Fired CWAF Factory Parameter Estimations

Annual Production Volume (units/year)	40,000
Work Days Per Year (days)	250
Assembly Shifts Per Day (shifts)	1
Fabrication Shifts Per Day (shifts)	2
Assembly Labor Wages ($/hr)	$16
Fabrication Labor Wages ($/hr)	$16
Length of Shift (hrs)	8
Average Equipment Installation Cost (% of purchase price)	10%
Fringe Benefits Ratio	50%
Indirect to Direct Labor Ratio	33%
Average Scrap Recovery Value	30%
Worker Downtime per shift	10%
Burdened Assembly Labor Wage ($/h)	$24
Burdened Fabrication Labor Wage ($/h)	$24
Supervisor Span (workers/supervisor)	25
Supervisor Wage Premium (over fabrication and assembly wage)	30%

Table 5.7.3 Oil-Fired CWAF Factory Parameter Estimations

Annual Production Volume (units/year)	2,500
Work Days Per Year (days)	250
Assembly Shifts Per Day (shifts)	1
Fabrication Shifts Per Day (shifts)	2
Assembly Labor Wages ($/hr)	$16
Fabrication Labor Wages ($/hr)	$16
Length of Shift (hrs)	8
Average Equipment Installation Cost (% of purchase price)	10%
Fringe Benefits Ratio	50%
Indirect to Direct Labor Ratio	33%
Average Scrap Recovery Value	30%
Worker Downtime per shift	10%
Burdened Assembly Labor Wage ($/h)	$24
Burdened Fabrication Labor Wage ($/h)	$24
Supervisor Span (workers/supervisor)	25
Supervisor Wage Premium (over fabrication and assembly wage)	30%

5.7.4.4 Material Price Estimations

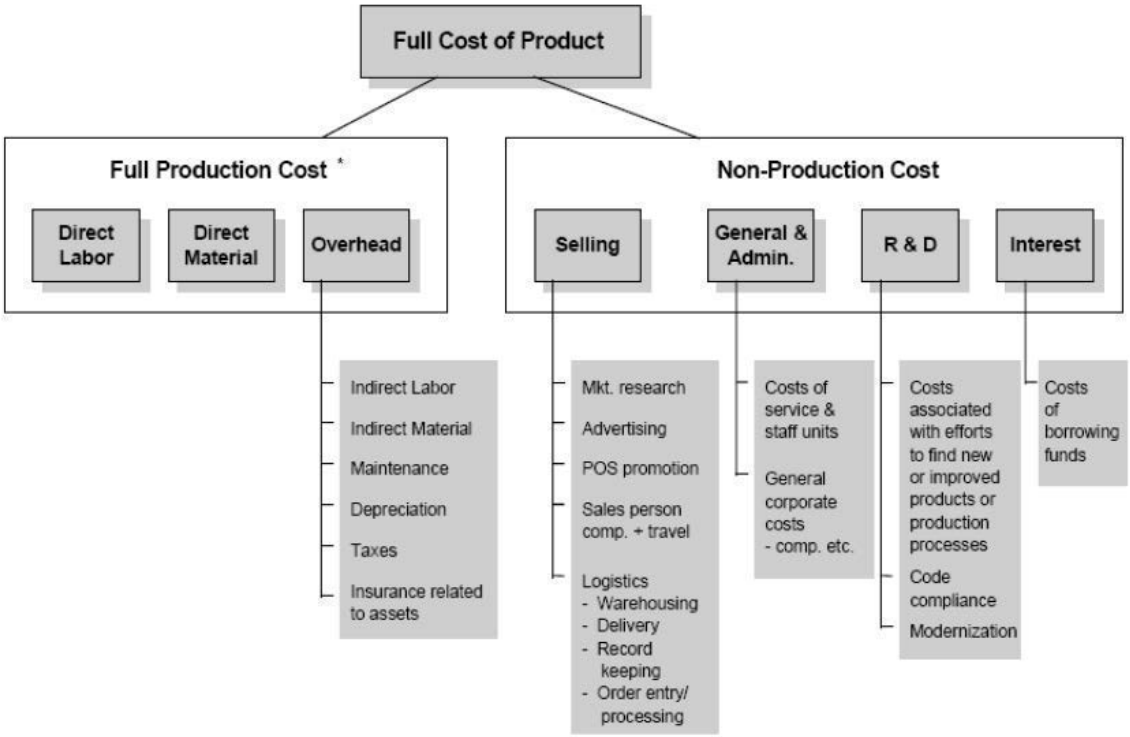
DOE determined the cost of raw materials using publicly available information such as the American Metals Market[2], Bureau of Labor Statistics Producer Price Indices (PPIs)[3] spanning 2010 to 2015, interviews with manufacturers, and discussions with material suppliers. The fabricated components of CWAF are made from raw metals, insulation, and plastic. To minimize the impact of large fluctuations in metal prices in recent years, DOE used a 5-year average for its metal raw materials prices. For non-metal raw material prices, DOE used the market prices at the time of the engineering analysis. Table 5.7.4 shows the material prices DOE used for the analysis.

Table 5.7.4 Material Prices

Metals	**Cost (Average nominal value across five-year span of 2/2010-1/2015) $/lb**
Plain Cold Rolled Steel (CRS)	$0.45
Aluminized CRS	$0.55
Aluminized CRS tube	$0.90
Galvanized CRS	$0.54
Pre-Painted CRS	$0.68
409 grade stainless steel (SS409)	$1.49
SS409 tube	$2.35
316 grade stainless steel (SS316)	$2.49
SS316 tube	$4.23
Fin Aluminum	$1.42
AL 29-4C sheet stock	$8.04
AL 29-4C Tube material	$12.31
Non-metals	**Cost as of 1/2015 (expressed in 2014$) $/lb**
Foil Faced Fiberglass-Insulation	$1.51
Flexible high-alumina ceramic (*i.e.*, "Fiberfrax")	$2.00
Molded high-alumina ceramic (*i.e.*, "Durafrax")	$3.47
Polyvinyl-Chloride Materials	$0.94

5.7.5 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 overhead used to manufacture a product in order to calculate the MPC.



* Tax Reform Act of 1986, requires companies to measure cost of goods sold as the full production cost of the goods sold.

Figure 5.7.1 A General Breakdown of Costs Associated with Manufacturing a CWAF

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.

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.

5.8 COST VERSUS EFFICIENCY CURVES

Cost versus efficiency curves for each equipment class are a key output of the engineering analysis.These curves depict the incremental MPC increases that correspond with incremental increases in efficiency above the baseline efficiency level. The slopes between the points on the cost versus efficiency curves vary depending on the technology options necessary to achieve each efficiency level. As described previously, in order to determine the increase in production cost at each efficiency level, DOE conducted a number of physical and virtual teardowns.

The resulting MPCs from the physical and virtual teardowns of gas-fired CWAF allowed DOE to develop a cost versus efficiency curve for that equipment class. In the LCC/PBP analysis

DOE estimated that certain percentages of weatherized gas-fired CWAF at the 80% TE, 81% TE, and 82% TE efficiency levels will incorporate different materials into the construction of the heat exchanger/inducer assemblies of each unit based on the required corrosion resistance of the material. DOE also estimated that non-weatherized units account for 5% of gas-fired CWAF installations at each of the 80% TE, 81% TE, and 82% TE efficiency levels, and that all of these units would incorporate aluminized steel heat exchangers. The percentages of all gas-fired CWAF units estimated to use each material type at the 80% TE, 81% TE, and 82% TE efficiency levels are shown in Table 5.8.1. DOE calculated a material-specific MPC for each of the heat exchanger/inducer assembly material types manufacturers may use at each efficiency level (the material-specific MPCs are presented in detail in section 5.10.1). These material-specific MPCs were used to develop an aggregate MPC for each of the 80% TE, 81% TE, and 82% TE efficiency levels, which weights each of the material-specific MPCs calculated for a given efficiency level by the percentage of units (as estimated by the LCC/PBP analysis) which use that material type at the given efficiency level. The cost versus efficiency curve for gas-fired CWAF (depicted by Figure 5.8.1) relates the aggregate MPCs calculated for each efficiency level, as well as the MPC calculated for the 92% TE efficiency level.

Table 5.8.1 Breakdown of Heat Exchanger Material Type by Efficiency Level*

Thermal Efficiency (%)	Aluminized CRS	SS409	SS316
80	85.75%	10.69%	3.56%
81	85.75%	10.69%	3.56%
82	5.00%	23.75%	71.25%

*This table represents the estimates made in the LCC/PBP analysis for gas-fired CWAF (see chapter 8 of the TSD) of the percentage of units sold at each efficiency level with a heat exchanger/inducer assembly design primarily incorporating each of the specific material types listed.

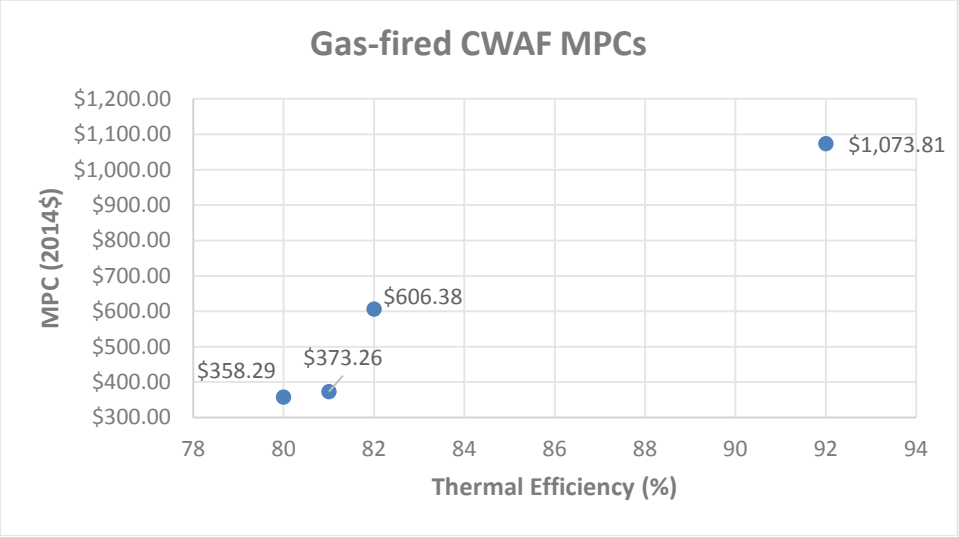


Figure 5.8.1 MPC versus Thermal Efficiency for Gas-Fired CWAF

Gas-fired CWAF typically share a common cabinet with a CUAC; however, the cost versus efficiency curve for gas-fired CWAF only depicts the costs related to the furnace components of the unit, and does not depict the costs related to the air conditioning components. The cost of the cabinet which encloses both the CUAC and CWAF components is also not accounted for, aside from at the 92% TE efficiency level, where the incremental cabinet expansion required to accommodate the secondary heat exchanger is represented in the estimated production cost. To raise efficiency from 80% TE to 81% TE, costs increase due to an enlargement of the size of the heat exchanger. To increase efficiency from 81% TE to 82% TE, costs increase significantly due to both a further enlargement of the size of the heat exchanger, and the increased usage of more expensive, high-grade corrosion-resistant stainless steel. To increase efficiency from 82% TE to 92% TE, costs increase significantly, primarily due to the implementation of a highly corrosion resistant secondary heat exchanger constructed from AL 29-4C material. In addition, the implementation of a highly-corrosion resistant inducer assembly, a condensate management system, and increased cabinet size to accommodate the secondary heat exchanger contribute to the incremental cost of achieveing 92% TE.

The resulting MPCs from the physical and virtual teardowns of oil-fired CWAF allowed DOE to develop a cost versus efficiency curve for oil-fired CWAF, which is depicted in Figure 5.8.2.

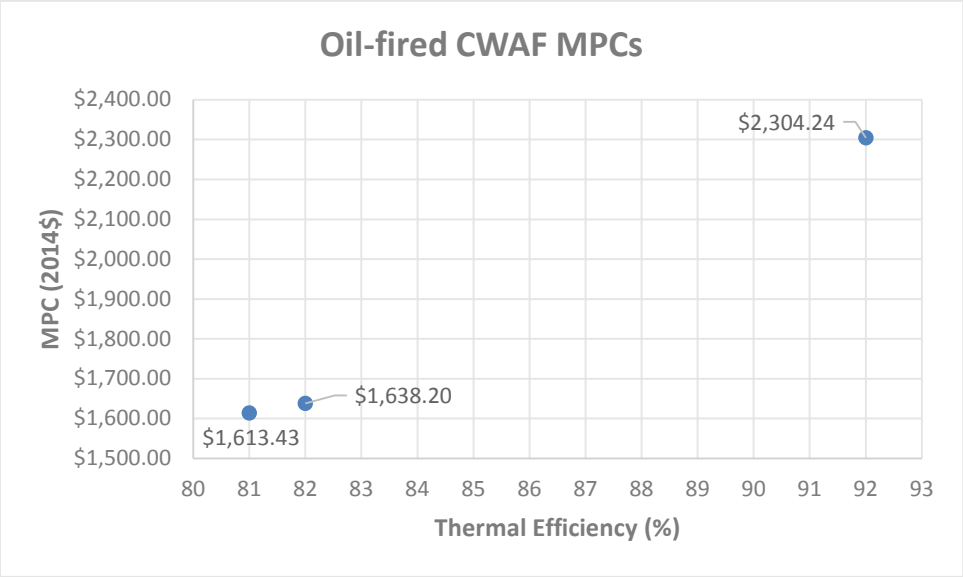


Figure 5.8.2 MPC versus Thermal Efficiency for Oil-Fired CWAF

For oil-fired CWAF, from 81% TE to 82% TE, there is a relatively small increase in cost due to increased heat exchanger size, as well as increased cabinet size to accommodate the larger heat exchanger. From 82% TE to 92% TE, the cost increases markedly due to the addition of a secondary high-grade stainless steel heat exchanger and a condensate management system, as well as increased blower fan size. These design changes require an increase in cabinet size.

5.9 MANUFACTURER MARKUP

To meet new or amended energy conservation standards, manufacturers often introduce design changes to their equipment lines, which often result in increased MPCs. Depending on the competitive environment for a particular equipment type, 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 typically will cover both of these contributions to overhead if a company is to maintain profitability. As discussed previously, overhead costs are a function of investments, material costs, labor costs, or total costs, depending on the overhead category. Together, materials, labor, depreciation, 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, 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 ("manufacturer 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 (discussed in chapter 6 of this TSD) convert MSP to customer price. Customer prices and installation costs are key inputs to the LCC/PBP analyses, and the NIA. Using manufacturer and distribution chain markups and installation costs, DOE can calculate the first costs that customers would face at each efficiency level. DOE evaluates the tradeoff between the increase in first cost and the resulting changes in operating costs at each efficiency level in the LCC/PBP analyses (see chapter 8 of the TSD), and NIA (see chapter 10 of the TSD).

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 (one-time expenditures). A low markup implies that manufacturers will not be able to recover as much of the necessary investment in plant and equipment.

5.9.1 Manufacturer Selling Price

The MSP is the price the manufacturer charges its first customer.. DOE analyzed the shipping cost (typically considered a nonproduction cost and included in the manufacturer markup) separately from the manufacturer markup. DOE calculated the MSP by multiplying the MPC by the manufacturer markup, and then adding the shipping cost.

5.9.2 Manufacturer Markup

Applying a manufacturer markup to the MPC of the equipment is the first step to calculating the MSP. In general, manufacturers ensure that the MSP of the equipment is high enough to recover the full cost of the equipment (*i.e.*, full production and nonproduction costs), and generate a satisfactory profit.

DOE used U.S. Security and Exchange Commission (SEC) 10-K reports from publicly traded manufacturers of CWAF equipment to estimate markups for the covered equipment. United States law requires publicly owned companies to disclose financial information on a regular basis by filing forms with the SEC. The SEC form 10-K, filed by companies annually, provides an overview of the company's business and financial conditions. The 10-K report includes the company's revenues and direct and indirect costs. The income statement section of the 10-K often lists the figures necessary for calculating the manufacturer markup—the net sales, costs of sales, and gross profit. DOE calculated a market-share weighted manufacturer markup to represent the CWAF industry. DOE applied this manufacturer markup to the MPCs to arrive at a final MSPs. This industry wide markup was further calibrated based on feedback received during manufacturer interviews. For the final rule analysis, DOE estimated an industry-average manufacturer markup of 1.31 for gas-fired CWAF and 1.28 oil-fired CWAF equipment.

5.9.3 Shipping Costs

Manufacturers of HVAC equipment typically pay for shipping to the first step in the distribution chain. Freight is not a manufacturing cost; but because it is a substantial cost incurred by the manufacturer and varies with equipment efficiency (due to changes in equipment size), DOE is accounting for shipping costs of CWAF separately from other non-production costs that comprise the manufacturer markup. To calculate the MSP for CWAF, DOE multiplied the MPC at each efficiency level by the manufacturer markup and added shipping costs for equipment at the given efficiency level.

For gas-fired CWAF, DOE calculated shipping costs at each efficiency level based on estimates of the outer dimensions of equipment at the given efficiency level and the use of a flat-bed, step-deck, or double-drop trailer.[a] DOE took into account that units in the gas-fired CWAF equipment class are almost exclusively installed within a cabinet that also contains a CUAC. DOE determined from product literature that manufacture of a gas-fired CWAF at 80% TE, 81% TE, or 82% TE in the same cabinet as a CUAC rarely necessitates the expansion of the cabinet beyond the dimensions required to accommodate only a CUAC in the same cabinet. As such, combination CUAC and gas-fired CWAF units at 80% TE, 81% TE, and 82% TE are generally shipped using the exact same trailer space that would be required if the CUAC were its own solitary unit. Therefore, DOE determined that there are zero shipping costs for gas-fired CWAF at these efficiency levels, because they demand zero additional trailer space beyond the space already required to ship the CUAC they are packaged with.[b] However, at the 92% TE (max-tech) efficiency level for gas-fired CWAF, shipping costs increase because a combined CWAF and CUAC package occupies greater trailer space than a CUAC-only package, due to the additional cabinet size required to accommodate the secondary heat exchanger. To approximate these additional shipping costs, DOE used the shipping cost per trailer volume (as discussed further for oil-fired CWAF below) to represent the shipping cost per volume of equipment shipped on a flat-bed, step-deck, or double-drop trailer. DOE calculated the shipping cost for the max-tech

[a] As discussed in section 5.5.4, gas-fired CWAF are typically packaged with a CUAC. The size of a combination CWAF and CUAC unit makes it too large to be shipped in a typical enclosed trailer, and instead requires that an open type of trailer be used.
[b] For information about the shipping costs of CUAC equipment, see chapter 5 of the CUAC TSD.

efficiency level by multiplying the shipping cost per volume by the incremental increase in volume required to accommodate a secondary heat exchanger in a 92% TE CWAF.

For oil-fired CWAF, DOE calculated shipping costs at each efficiency level based on estimates of the outer dimensions of equipment at the given efficiency level and the use of a typical 53-foot straight frame dry van trailer with a storage volume of 4,240 cubic feet. DOE determined that oil-fired CWAF are typically not double-stacked in a vertical fashion in the trailer due to their size and weight. As a result, the trailer area taken up by the equipment is often the limiting factor (as opposed to weight or volume) dictating how many oil-fired CWAF can be shipped in a truckload (although DOE notes it may be possible to stack other, smaller HVAC equipment on top of these units). Oil-fired CWAF are commonly shipped together in fully loaded trailers, rather than in less than truckload (LTL) configurations, where the the unit would only occupy a portion of the trailer volume. As such, the shipping costs were based on a trailer fully loaded with oil-fired CWAF. To calculate shipping costs, DOE calculated the cost per volume of a trailer, based on an estimated cost of $2,720 to ship a fully loaded trailer from coast-to-coast, and the standard dimensions of a 53-foot trailer. DOE then calculated the market-weighted average size of oil-fired CWAF at each efficiency level, and estimated the shipping cost for each efficiency level by multiplying equipment volume by the calculated shipping cost per volume of a standard trailer.

Table 5.9.1 and Table 5.9.2 show the average shipping dimensions of CWAF that DOE calculated for each equipment class and efficiency level. Table 5.9.3 shows the shipping costs of a CWAF when packaged together with a CUAC in the same cabinet, as well as theestimated shipping costs for oil-fired CWAF. These values were used as inputs to the calculation of MSPs.

Table 5.9.1 Shipping Dimensions for Gas-Fired CWAF*

Efficiency Level	Height (in)	Width (in)	Depth (in)	Box Volume (ft^3)
80%	50	87	58	146.84
81%	50	87	58	146.84
82%	50	87	58	146.84
92%	60	87	58	175.33

* Gas-fired CWAF dimensions represent the dimensions of the entire cabinet encasing both the CWAF and CUAC components.

Table 5.9.2 Shipping Dimensions for Oil-Fired CWAF

Efficiency Level	Height (in)	Width (in)	Depth (in)	Box Volume (ft^3)
81%	60	80	33	91.67
82%	62	82	34	100.03
92%	72	80	33	110.00

Table 5.9.3 CWAF Shipping Cost Estimates

CWAF Equipment Class	Thermal Efficiency	Shipping Costs* (2014$)
Gas-Fired CWAF	80%	$0
	81%	$0
	82%	$0
	92%	$43.15
Oil-Fired CWAF	81%	$69.43
	82%	$75.76
	92%	$83.31

* The shipping costs shown for gas-fired CWAF at 80% TE, 81% TE, and 82% TE are zero because most gas-fired CWAF are packaged with a CUAC, and at these efficiency levels a combined CUAC and gas-fired CWAF package does not occupy any more space in a shipping trailer than a CUAC-only package. The shipping cost shown for 92% TE only reflects the costs associated with the incremental increase in shipping trailer space required at 92% TE, and not the shipping costs associated with the entire CUAC and CWAF package.The shipping costs shown for oil-fired CWAF are representative of the cost to ship the entire unit, as these systems do not contain air conditioning components that influence the shipping cost.

5.10 ENGINEERING ANALYSIS SUMMARY OF RESULTS

The results of the engineering analysis are used in the LCC analysis to determine customer prices for CWAF. By applying the calculated manufacturer markup and shipping costs to the MPCs, DOE calculated the MSPs of CWAF at the baseline and all higher efficiency levels for each equipment class.

5.10.1 Summary of Results for Representative Models

Each of the MPCs and MSPs developed in the CWAF engineering analysis for representative capacity units in each equipment class are shown in Table 5.10.1 through Table 5.10.4. As discussed previously in section 5.5.4, MPCs for gas-fired CWAF at 80% TE, 81% TE, and 82% TE were calculated for three different material types of varying corrosion resistance that manufacturers may utilize in the design of a unit's heat exchanger and inducer assemblies (these materials are: aluminized steel, SS409, and SS316). As described in section 5.9.1, the MSP for CWAF is calculated by multiplying the MPC by the manufacturer markup and then adding the shipping cost.

Table 5.10.1 MPC and MSP for Gas-Fired CWAF- Aluminized Steel Heat Exchanger and Inducer Assembly Components at 80% TE, 81% TE, and 82% TE

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (80% TE)	$337.21	$441.74
EL1 (81% TE)	$350.40	$459.03
EL2 (82% TE)	$357.42	$468.22
Max-tech (92% TE)	$1,073.81	$1,449.84

Table 5.10.2 MPC and MSP for Gas-Fired CWAF- SS409 Heat Exchanger and Inducer Assembly Components at 80% TE, 81% TE, and 82% TE

Efficiency Level	MPC 2014$	MSP 2014$

Baseline (80% TE)	$447.01	$585.58
EL1 (81% TE)	$469.39	$614.90
EL2 (82% TE)	$485.62	$636.16
Max-tech (92% TE)	$1,073.81	$1,449.84

Table 5.10.3 MPC and MSP for Gas-Fired CWAF- SS316 Heat Exchanger and Inducer Assembly Components at 80% TE, 81% TE, and 82% TE

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (80% TE)	$599.48	$785.32
EL1 (81% TE)	$634.86	$831.67
EL2 (82% TE)	$664.10	$869.97
Max-tech (92% TE)	$1,073.81	$1,449.84

Table 5.10.4 MPC and MSP for Oil-Fired CWAF

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (81%)	$1,613.43	$2,065.19
EL1 (82%)	$1,638.20	$2,096.89
Max-tech (92%)	$2,304.24	$2,949.43

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CHAPTER 6. MARKUPS ANALYSIS

TABLE OF CONTENTS

6.1 INTRODUCTION 6-1
6.2 DISTRIBUTION CHANNELS 6-1
6.3 APPROACH FOR MANUFACTURER MARKUP 6-3
6.4 APPROACH FOR WHOLESALER AND CONTRACTOR MARKUPS 6-4
6.4.1 Wholesaler Markup 6-5
6.4.2 Mechanical and General Contractor Markups 6-6
6.5 APPROACH FOR CALCULATING OVERALL MARKUP OF THE NATIONAL ACCOUNTS DISTRIBUTION CHANNEL 6-7
6.6 DERIVATION OF MARKUPS 6-8
6.6.1 Manufacturer Markup 6-8
6.6.2 Wholesaler Markup 6-9
6.6.3 Mechanical Contractor Markups 6-10
6.6.3.1 Aggregate Markups for Mechanical Contractors 6-10
6.6.3.2 Markups for Mechanical Contractors in the Replacement and New Construction Markets 6-11
6.6.3.3 Markups for Small and Large Mechanical Contractors 6-13
6.6.3.4 Markups by Disaggregated Mechanical Contractor Type 6-14
6.6.4 General Contractor Markups 6-15
6.7 DERIVATION OF REGIONAL MARKUPS 6-18
6.7.1 Estimation of Wholesaler Markups 6-18
6.7.2 Estimation of Mechanical Contractor Markups 6-20
6.7.3 Estimation of General Contractor Markups 6-24
6.8 SALES TAX 6-25
6.9 OVERALL MARKUPS 6-27

LIST OF TABLES

Table 6.2.1 Shares of Market by Distribution Channel 6-3
Table 6.6.1 Manufacturer Markups by Commercial Warm Air Furnace Equipment Class 6-9
Table 6.6.2 Wholesaler Expenses and Markups 6-9
Table 6.6.3 Mechanical Contractor Expenses and Markups Based on Census Bureau Data 6-11
Table 6.6.4 Baseline Markup, All Mechanical Contractors 6-12
Table 6.6.5 Baseline Markups for the Replacement and New Construction Markets, All Mechanical Contractors 6-13
Table 6.6.6 Baseline Markups for Small and Large Mechanical Contractors 6-14
Table 6.6.7 Baseline and Incremental Markups by Mechanical Contractor Type 6-15
Table 6.6.8 Commercial Building General Contractor Expenses and Markups 6-16
Table 6.6.9 Residential Building General Contractor Expenses and Markups 6-17

Table 6.7.1 Regional Wholesaler Markups for Commercial Warm Air Furnaces in Commercial Applications 6-19
Table 6.7.2 Regional Wholesaler Markups for Commercial Warm Air Furnaces in Residential Applications 6-20
Table 6.7.3 Population-Weighted Small Mechanical Contractor Markups for Commercial Warm Air Furnaces in Commercial Application 6-21
Table 6.7.4 Population-Weighted Large Mechanical Contractor Markups for Commercial Warm Air Furnaces in Commercial Application 6-22
Table 6.7.5 Population-Weighted Mechanical Contractor Markups for Commercial Warm Air Furnaces in Residential Application 6-23
Table 6.7.6 Population-Weighted General Contractor Markups for Commercial Warm Air Furnaces in Commercial Application 6-24
Table 6.7.7 Population-Weighted General Contractor Markups for Commercial Warm Air Furnaces in Residential Application 6-25
Table 6.8.1 Average Sales Tax Rates by CBECS 2003 Region 6-26
Table 6.8.2 Average Sales Tax Rates by RECS 2009 Region 6-27
Table 6.9.1 Summary of Overall Markups on Commercial Warm Air Furnaces in Commercial Applications 6-29
Table 6.9.2 Summary of Overall Markups on Commercial Warm Air Furnaces in Residential Applications 6-30
Table 6.9.3 Summary of Markup by Commercial Warm Air Furnace Equipment Class 6-30

LIST OF FIGURES

Figure 6.2.1 Distribution Channels for Commercial Warm Air Furnaces (Replacement Applications) 6-2
Figure 6.2.2 Distribution Channels for Commercial Warm Air Furnaces (New Construction Applications) 6-3

CHAPTER 6. MARKUPS ANALYSIS

6.1 INTRODUCTION

To carry out its analyses, the U.S. Department of Energy (DOE) needed to determine the cost to the customer of baseline equipment and the cost of more-efficient units the customer 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 commercial warm air furnaces (CWAF).

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 customer 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 customer purchase price for the same equipment. Because companies mark up the price at each point in the distribution channel, both baseline and incremental markups are dependent on the distribution channel, as described in section 6.2.

Generally, companies mark up the price of equipment 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) and interest expenses; depreciation; and taxes—and company profits. In order for sales of equipment to contribute positively to company cash flow, the equipment's markup must be greater than the corporate gross margin. Equipment commands lower or higher markups, depending on company expenses associated with the equipment and the degree of market competition.

6.2 DISTRIBUTION CHANNELS

The appropriate markups for determining customer equipment prices depend on the type of distribution channels through which the equipment moves from manufacturers to purchasers. At each point in the distribution channel, companies markup the price of the equipment to cover their business costs and profit margin. In the case of CWAF, the majority of them are purchased for commercial use, but a small fraction of CWAF are purchased to be installed in large residential buildings. DOE estimated that 98 percent of total CWAF shipments are to commercial applications and 2 percent to residential applications.

Within each application, there are two primary types of distribution channels describing the way most equipment passes from the manufacturer to the customer, one involving distributors and contractors and one from manufacturer to customer via national accounts. Within these two primary channels, DOE distinguishes between new and replacement markets,

as only new construction applications are expected to include a general contractor. DOE also distinguishes between small and large mechanical contractors. In the replacement market, the manufacturer sells the equipment to a wholesaler, who in turn sells it to either a small or large mechanical contractor, who in turn sells it to the customer. In the new construction market, the manufacturer sells the equipment to a wholesaler, who in turn sells it to either a small or large mechanical contractor, who in turn sells it to a general contractor then to the customer.

Distribution channels for replacement and new construction applications are shown in Figure 6.2.1 and Figure 6.2.2, respectively. DOE also considers an additional distribution channel in which the manufacturer sells the equipment to the wholesaler and then to the customer through a national account under both replacement and new construction markets. This national account distribution channel is applicable when building managers directly purchase equipment from manufacturers at much lower prices due to the large volume purchased and install the equipment themselves; therefore, no additional contractor is needed to install the equipment.

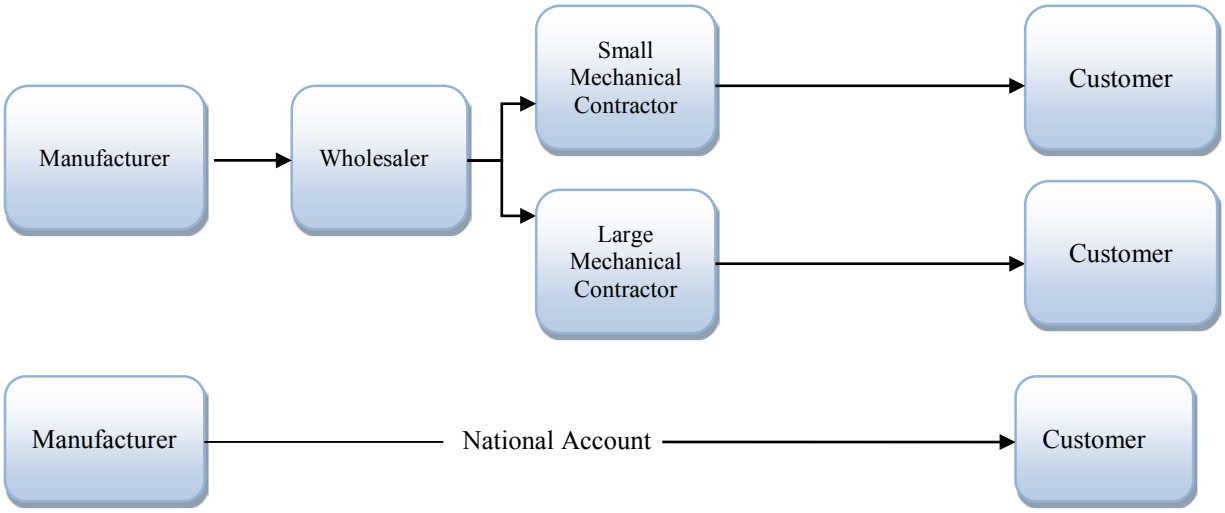

Figure 6.2.1 Distribution Channels for Commercial Warm Air Furnaces (Replacement Applications)

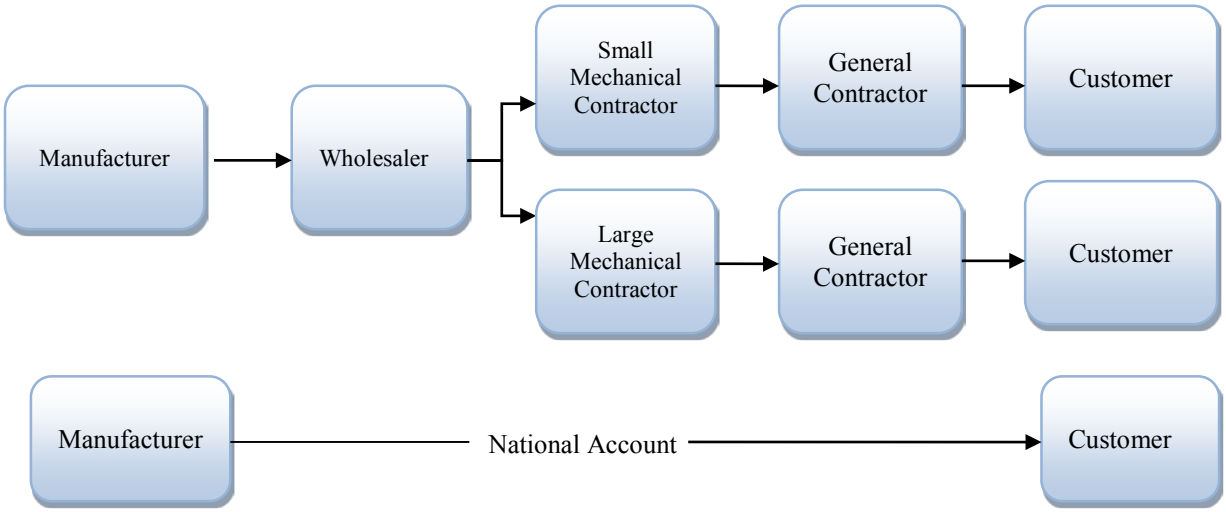

Figure 6.2.2 Distribution Channels for Commercial Warm Air Furnaces (New Construction Applications)

Based on information that equipment manufacturers provided, end-use commercial consumers purchase 50 percent of equipment through small mechanical contractors, 32.5 percent through large mechanical contractors, and the remaining 17.5 percent through national accounts.[1]

In addition, based on shipments data (see chapter 9) DOE estimated that 80 percent of gas-fired CWAF and 95 percent of oil-fired CWAF are purchased for the replacement market while the remaining 20 percent of gas-fired CWAF and 5 percent of oil-fired CWAF are assumed to serve the new construction market. Table 6.2.1 lists each distribution channel's share of the full CWAF market.

Table 6.2.1 Shares of Market by Distribution Channel

Distribution Channel		Share of Total Market	
		Gas-fired CWAF	Oil-fired CWAF
Replacement	Small Mechanical Contractor	40.0%	47.5%
	Large Mechanical Contractor	26.0%	30.9%
	National Account	14.0%	16.6%
New Construction	Small Mechanical Contractor	10.0%	2.5%
	Large Mechanical Contractor	6.5%	1.6%
	National Account	3.5%	0.9%

6.3 APPROACH FOR MANUFACTURER MARKUP

DOE uses manufacturer markups to transform a manufacturer's equipment cost into a manufacturer sales price. A detailed description of the methodology used to derive manufacturer markups were described in chapter 5, Engineering Analysis.

6.4 APPROACH FOR WHOLESALER AND CONTRACTOR MARKUPS

DOE examined the manner in which wholesaler and contractor markups may change in response to changes in CWAF efficiency levels and other factors. Using the available data, DOE estimated that there are differences between *incremental* markups on incremental equipment costs of higher efficiency equipment and the *baseline* markup on direct business costs of equipment with baseline efficiency.

DOE derived the wholesaler and contractor markups from three key assumptions about the costs associated with CWAF. DOE based the wholesaler and mechanical contractor markups on firm-level income statement data and based the general contractor markups on U.S. Census Bureau data for the commercial building construction industry. DOE obtained the firm income statements from the Heating, Air-conditioning & Refrigeration Distributors International (HARDI) 2012 Profit Report and from the Air Conditioning Contractors of America (ACCA) 2005 Financial Analysis.[2,3] HARDI and ACCA are trade associations representing wholesalers and mechanical contractors, respectively. DOE used the financial data from the 2007 U.S. Census of Business for developing general contractor markups in the same form as the income statement data for wholesalers and mechanical contractors. These income statements break down the components of all costs incurred by firms that supply and install heating and air-conditioning equipment.[a] The key assumptions used to estimate markups using these financial data are:

1. The firm income statements faithfully represent the various average costs incurred by firms distributing and installing CWAF.

2. These costs can be divided into two categories: 1) costs that vary in proportion to the MSP of CWAF (variant costs); and 2) costs that do not vary with the MSP of CWAF (invariant costs).

3. Overall, wholesale and contractor prices for CWAF vary in proportion to the wholesaler and contractor costs for CWAF included in the income statements.

In support of the first assumption, the income statements 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 wholesalers and contractors tend to handle multiple commodity lines, including room air conditioners, furnaces, central air conditioners and heat pumps, and furnaces, the data provide the most accurate available indication of the expenses associated with CWAF.

Information obtained from the trade literature, selected heating, ventilating, and air conditioning (HVAC) wholesalers, contractors, and consultants tends to support the second assumption. This information indicates that wholesale and contractor markups vary according to

[a] Wholesalers and mechanical contractors to which these reports refer handle multiple commodity lines.

the quantity of labor and materials used to distribute and install appliances. In the following discussion, DOE assumes a division of costs between those that do not scale with the manufacturer price (labor and occupancy expenses) and those that do (operating expenses and profit).

In support of the third assumption, the HVAC wholesaler and contractor industry is competitive, and customer demand for heating and air conditioning is inelastic, *i.e.*, the demand is not expected to decrease significantly with an increase in the price of equipment. The large number of HVAC firms listed in the 2007 Census indicates the competitive nature of the market. For example, there are more than 700 HVAC manufacturers,[4] 5,300 wholesalers of heat pumps and air-conditioning equipment,[5] 36,000 commercial and institutional building contractors,[6] and 91,000 HVAC contractors[7] listed in the 2007 Census. Following standard economic theory, competitive firms facing inelastic demand either set prices in line with costs or quickly go out of business.[8]

DOE concluded that markups for more efficient equipment are unlikely to be proportional to all direct costs. When the wholesaler's purchase price of equipment increases, only a fraction of a business' expenses increases, while the remainder may stay relatively constant. For example, if the unit price of a CWAF unit increases by 30 percent due to improved efficiency, it is unlikely that the cost of secretarial support in an administrative office will increase by 30 percent also. Therefore, DOE assumed that incremental markups cover only those costs that scale with a change in the MSP (variant costs).

6.4.1 Wholesaler Markup

Using the previously described assumptions, DOE developed baseline and incremental markups for wholesalers using the firm income statement from the HARDI 2012 Profit Report (see appendix 6A). 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 coefficients that relate the change in the MSP of more energy-efficient models, or equipment that meets the requirements of new energy conservation standards, to the change in the wholesaler sales price. Incremental markups cover only those costs that scale with a change in the MSP (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 Mechanical and General Contractor Markups

The type of financial data used to estimate markups for wholesalers is also available for mechanical contractors and general contractors from the 2007 Economic Census and ACCA 2005 Financial Analysis. To estimate mechanical contractor markups for CWAF, DOE collected financial data from the *Plumbing and HVAC Contractors* (NAICS 23822) series from the 2007 Economic Census and from ACCA 2005 Financial Analysis. To estimate general contractor markups for CWAF installed in commercial buildings, DOE collected data from the Commercial Building Construction series (NAICS 236220) from the 2007 Economic Census. To estimate general contractor markups for CWAF in residential applications, DOE collected data from the Residential Building Construction series from the 2007 Economic Census. ACCA financial data provide GM as percent of sales for the mechanical contractor industry; therefore, baseline markup can be derived with the following equation:

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

Eq. 6.3

The U.S. Census data include the number of establishments, payroll for construction workers, value of construction, cost of materials, and cost of subcontracted work at both state and national levels. DOE calculated the baseline markup for mechanical contractors and general contractors using the following equation:

$$MU_{BASE} = \frac{V_{CONSTRUCT}}{Pay + MatCost + SubCost}$$

Eq. 6.4

Where:

MU_{BASE} = baseline mechanical contractor or general contractor markup,
$V_{CONSTRUCT}$ = value of construction,
Pay = payroll for construction workers,
$MatCost$ = cost of materials, and
$SubCost$ = cost of subcontracted work.

Analogously, 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 equipment. As stated previously, DOE assumes 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 cost data in each major cost category and estimated markups using the following equation:

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

Eq. 6.5

Where:

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

6.5 APPROACH FOR CALCULATING OVERALL MARKUP OF THE NATIONAL ACCOUNTS DISTRIBUTION CHANNEL

Equipment purchased through national accounts is an exception to the usual distribution to end users. Large commercial consumers of HVAC equipment use national accounts to circumvent the typical chain of distribution, thereby allowing them to negotiate equipment prices directly with the manufacturer. Due to the large volume of equipment purchased, large commercial customers are able to purchase equipment directly from the manufacturer at significantly lower prices than could be obtained through the typical distribution chain.

To capture the price savings realized from equipment purchased through national accounts, DOE derived a "national account" markup, assuming that the resulting equipment price increase was one half of that realized from a typical chain of distribution. In other words, if the price increase resulting from the product of the wholesale, mechanical contractor, and general contractor markups is $100, the "national account" markup is such that the price increase is one-half of that, or $50. DOE based the use of a "national account" markup that is one-half of that realized from a typical chain of distribution on the assumption that the resulting "national account" equipment price must fall somewhere between the manufacturer price (i.e., a markup of 1.0) and the commercial customer price under a typical chain of distribution. Because DOE did

not know typical values for the actual "national account" equipment price, it chose a value of one-half.

The estimates of national account markups are estimated through a distribution of 61 percent and 39 percent to the markups for small and large contractors, respectively. As stated above, 50 percent of all sales are through a distribution channel involving a small mechanical contractor and 32.5 percent are through a distribution channel involving a large mechanical contractor, and 17.5 percent are through a national account. Therefore, of all sales involving mechanical contractors, 61 percent are small contractors and 39% are large contractors. The national account markup is also calculated separately for new construction and replacement, as well as baseline and incremental markups.

DOE arrives at the estimated national account markup, by calculating half of the overall markup calculated for non-national account distribution channel and adding 1 as follows:

$$MU_{OVERALL_NA} = \frac{MU_{OVERALL} - 1}{2} + 1$$

Eq. 6.6

Where:

$MU_{OVERALL}$= overall markup calculated for non-national account distribution channel, and
$MU_{OVERALL_NA}$= national account overall markup.

6.6 DERIVATION OF MARKUPS

6.6.1 Manufacturer Markup

The methodology DOE used to determine the manufacturer markup for CWAF is similar to the methodology described in chapter 5 of the technical support document (TSD) for the Residential Central Air Conditioners, Heat Pumps, and Furnaces Direct Final Rule.[9] DOE used U.S. Security and Exchange Commission (SEC) 10-K reports from 2008 to 2012 from publicly-owned CWAF manufacturing companies to estimate manufacturer markups. Table 6.6.1 presents manufacturer markups for the two different equipment classes considered in this analysis.

Table 6.6.1 Manufacturer Markups by Commercial Warm Air Furnace Equipment Class

Equipment Class	Baseline Markup
Gas-fired CWAF	1.31
Oil-fired CWAF	1.28

6.6.2 Wholesaler Markup

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 (CGS), labor expenses, occupancy expenses, other operating expenses, and profit. DOE presents these data in full in appendix 6A. Table 6.6.2 summarizes them as cost-per-dollar sales revenue in the first data column.

Table 6.6.2 Wholesaler Expenses and Markups

Descriptions	Per Dollar Sales Revenue $	Per Dollar Cost of Goods $
Direct Cost of Equipment Sales: Cost of goods sold	0.737	1.000
Labor Expenses: Salaries and benefits	0.151	0.205
Occupancy Expense: Rent, maintenance, and utilities	0.036	0.049
Other Operating Expenses: Depreciation, advertising, and insurance.	0.055	0.075
Operating Profit	0.021	0.028
Wholesaler Baseline Markup ($MU_{WHOLE\ BASE}$)		**1.357**
Incremental Markup ($MU_{WHOLE\ INCR}$)		**1.103**

Source: Heating, Air Conditioning & Refrigeration Distributors International. 2012. 2012 Profit Report (2011 Data).

In this case, direct equipment expenses (CGS) 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 $0.06, 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 $0.205 to cover labor costs, $0.049 to cover occupancy expenses, $0.075 for other operating expenses, and $0.028 in profits. This totals to $1.357 in sales revenue earned for every $1.00 spent on equipment costs. Therefore, the wholesaler baseline markup ($MU_{WHOLE\ BASE}$) is 1.357 ($1.357 ÷ $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 6.6.2 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 $1.360, implying that the incremental markup is 1.360, 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 to match changes in "other" operating costs and operating profit of $0.076, which when divided by 73.7 cents in cost of goods sold yields an increase of $0.103, giving a wholesaler incremental markup ($MU_{WHOLE\ INCR}$) of 1.103.

6.6.3 Mechanical Contractor Markups

6.6.3.1 Aggregate Markups for Mechanical Contractors

The 2007 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 previously, baseline and incremental markups were estimated. The markup results are presented in Table 6.6.3. (Appendix 6A contains the full set of data.)

Table 6.6.3 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	0.68	1.00
Labor Expenses: Salaries (indirect) and benefits	0.18	0.26
Occupancy Expense: Rent, maintenance, and utilities	0.02	0.03
Other Operating Expenses: Depreciation, advertising, and insurance.	0.08	0.12
Net Profit Before Taxes	0.04	0.06
Baseline Markup (*MUMECH BASE*): Revenue per dollar cost of goods		**1.48**
Incremental Markup (*MUMECH INCR*): Increased revenue per dollar increase in cost of goods sold		**1.18**

Source: U.S. Census Bureau. 2007. Plumbing, Heating, and Air-Conditioning Contractors. Sector 23: 238220. Construction: Industry Series, Preliminary Detailed Statistics for Establishments, 2007.

The first data column in Table 6.6.3 provides the CGS 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 $0.68 per dollar sales revenue to the mechanical contractor, and the gross margin totals $0.32 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 $0.68. 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 $0.48 to cover the other costs. This totals $1.48 in sales revenue earned for every $1.00 spent on equipment costs. This is equivalent to a baseline markup ($MU_{MECH\ CONT\ BASE}$) of 1.48 for mechanical contractors.

DOE was also able to use the data in column two in Table 6.6.3 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 $1.48, implying that the incremental markup is 1.48 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 $1.18, giving a general contractor incremental markup ($MU_{MECH\ CONT\ INCR}$) of 1.18.

6.6.3.2 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 2007 Economic Census industrial cost data supplemented with

the most recent ACCA 2005 financial data.[3,10] 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 2007 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 6.6.4.

Table 6.6.4 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	0.73	1.00
Gross Margin: Labor, occupancy, operating expenses, and profit	0.27	0.37
Revenue: Baseline revenue earned per dollar cost of goods		**1.37**
Baseline Markup ($MU_{MECH\ CONT\ BASE}$)		**1.37**

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

Table 6.6.5 summarizes the gross margin and resulting baseline markup data for all mechanical contractors that serve the replacement and new construction markets.

Table 6.6.5 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	0.703	1.000	0.745	1.000
Gross Margin: Labor, occupancy, operating expenses, and profit	0.297	0.422	0.255	0.342
Baseline Markup (*MUMECH CONT BASE*): Revenue per dollar cost of goods	NA	**1.42**	NA	**1.34**
% Difference from Aggregate Mechanical Contractor Baseline MU	NA	**3.6%**	NA	**-2.2%**

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

Using the baseline markup data from Table 6.6.5 and results from Table 6.6.4, DOE calculated that the baseline markups for the replacement and new construction markets are 3.6 percent higher and 2.2 percent lower, respectively, than for all mechanical contractors serving all markets.

6.6.3.3 Markups for Small and Large Mechanical Contractors

ACCA provides data for contracting businesses earning annual revenues in each of the four following categories: (1) below one million dollars; (2) from one to two million dollars; (3) from two to five million dollars; and (4) over five million dollars. DOE aggregated the data into two categories: contractors earning annual revenue below two million dollars and contractors earning annual revenue above two million dollars. The values reported for small contractors are the average of the categories: (1) below one million dollars, and (2) from one to two million dollars. The values reported for large contractors are the average of the categories: (3) from two to five million dollars and (4) over five million dollars.

Table 6.6.6 Baseline Markups for Small and Large Mechanical Contractors

Description	Contractor Expenses or Revenue by Market Type			
	Small (< $2 million)		Large (> $2 million)	
	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	0.653	1.000	0.753	1.000
Gross Margin: Labor, occupancy, operating expenses, and profit	0.347	0.532	0.247	0.328
Baseline Markup (*MUMECH CONT BASE*): Revenue per dollar cost of goods	NA	**1.53**	NA	**1.33**
% Difference from Aggregate Mechanical Contractor Baseline MU	NA	**11.6%**	NA	**-3.2%**

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

Using the baseline markup data from Table 6.6.6, DOE calculated that the baseline markups for small and large contractors are 11.6 percent higher and 3.2 percent lower, respectively, than that for all mechanical contractors serving all markets shown in Table 6.6.4.

6.6.3.4 Markups by Disaggregated Mechanical Contractor Type

Using the percentage difference from the aggregate mechanical contractor baseline markup based on the 2005 ACCA financial data (Table 6.6.5 and Table 6.6.6), DOE estimated the baseline and incremental markups for each of the four mechanical contractor types, building upon the Census industry-level data derived in Table 6.6.3: (1) small contractors in the replacement market; (2) small contractors in the new construction market; (3) large contractors in the replacement market; and (4) large contractors in the new construction market. The results are summarized in Table 6.6.7. The baseline and incremental markup for each mechanical contractor type is estimated using the following equation:

$$MU_{MCONTRACT\ BASE/INCR} = MU_{AGGREGATE\ BASE/INCR} \times (1 + \mu_{SIZE} + \mu_{MARKET})$$

Eq. 6.7

Where:

$MU_{AGGREGATE\ BASE/INCR}$ = baseline or incremental markup for aggregate of all mechanical contractors,

μ_{SIZE} = size modifier (small or large contractor percentage difference from aggregate of all contractors' markup),

μ_{MARKET} = market modifier (replacement or new construction contractor percentage difference from aggregate of all contractors' markup), and

$MU_{MCONTRACT_BASE}$ = baseline markup for specific mechanical contractor type.

Table 6.6.7 Baseline and Incremental Markups by Mechanical Contractor Type

Mechanical Contractor Type		Size Modifier	Market Modifier	Baseline Markup	Incremental Markup
Size	**Market**				
Small	Replacement	11.6%	3.6%	**1.69**	**1.36**
	New Construction	11.6%	-2.2%	**1.61**	**1.29**
Large	Replacement	-3.2%	3.6%	**1.48**	**1.19**
	New Construction	-3.2%	-2.2%	**1.39**	**1.12**

6.6.4 General Contractor Markups

DOE derived markups for general contractors from U.S. Census Bureau data for the commercial and residential building construction sector. Both sectors include establishments primarily engaged in construction work, including new construction work, additions, alterations, and repairs of commercial buildings.[11]

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

Table 6.6.8 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	0.76	1.00
Labor Expenses: Salaries (indirect) and benefits	0.08	0.10
Occupancy Expense: Rent, maintenance, and utilities	0.01	0.01
Other Operating Expenses: Depreciation, advertising, and insurance.	0.03	0.04
Net Profit Before Taxes	0.12	0.15
Baseline Markup (*MUGEN CONT BASE*): Revenue per dollar cost of goods		**1.31**
Incremental Markup (*MUGEN CONT INCR*): Increased revenue per dollar increase cost of goods sold		**1.19**

Source: U.S. Census Bureau. 2007. Sector 236220 (Commercial Building Construction). Construction: Industry Series: Preliminary Detailed Statistics for Establishments: 2007.

As shown in the first column of Table 6.6.8, the direct cost of sales represents about $0.76 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 $0.03, and profit makes up $0.12 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 $0.76. 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, $0.01 to cover occupancy expenses, $0.04 for other operating expenses, and $0.15 in profits. This totals to $1.31 in sales revenue earned for every $1.00 spent on equipment costs. Thus, the general contractor baseline markup ($MU_{GCONTRACT_BASE}$) is 1.31.

DOE was also able to use the data in column two of Table 6.6.8 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 $1.48, implying that the incremental markup is 1.48, 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 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 $1.19, giving a general contractor incremental markup ($MU_{GCONTRACT_INCR}$) of 1.19.

Table 6.6.9 summarizes the expenses for general contractors in residential building construction at the national level as expenses per dollar sales revenue in the first data column. (Appendix 6A contains the full set of data.)

Table 6.6.9 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	0.68	1.00
Labor Expenses: Salaries (indirect) and benefits	0.08	0.12
Occupancy Expense: Rent, maintenance, and utilities	0.01	0.01
Other Operating Expenses: Depreciation, advertising, and insurance.	0.06	0.09
Net Profit Before Taxes	0.17	0.25
Baseline Markup (*MUGEN CONT BASE*): Revenue per dollar cost of goods		**1.47**
Incremental Markup (*MUGEN CONT INCR*): Increased revenue per dollar increase in cost of goods sold		**1.34**

Source: U.S. Census Bureau. 2007. Residential Building Construction. Sector 236110. Construction: Industry Series: Preliminary Detailed Statistics for Establishments: 2007

As shown in the first column, the direct cost of sales represents about $0.68 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 $0.03, and profit makes up $0.17 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 $0.68. 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, $0.12 to cover labor costs, $0.01 to cover occupancy expenses, $0.09 for other operating expenses, and $0.25 in profits. This totals to $1.47 in sales revenue earned for every $1.00 spent on equipment costs. Thus, the general contractor baseline markup ($MU_{GEN\ CONT\ BASE}$) is 1.47.

DOE used the data in column two in Table 6.6.9 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 $1.47, implying that the incremental markup is 1.47, 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 $1.34, giving a general contractor incremental markup ($MU_{GEN\ CONT\ INCR}$) of 1.34.

6.7 DERIVATION OF REGIONAL MARKUPS

In this analysis, DOE considered two different CWAF equipment classes. DOE assumed a market saturation rate for each equipment class that varies by geographical region defined by the Energy Information Administration's (EIA) 2003 Commercial Building Energy Consumption Survey (CBECS 2003) and on EIA's 2009 Residential Energy Consumption Survey (RECS 2009), based on the state population forecasts for the year 2019.[12,13,b] Therefore, regional markups were calculated for each CWAF equipment class.

Wholesalers and mechanical and general contractors in the CWAF industry were divided into the nine census regions provided by the CBECS 2003 for the commercial application and the 30 regions[c] provided by the RECS 2009 for the residential application. Regional baseline and incremental markups were derived using the region/state level data from the 2012 HARDI Profit Report and the 2007 Economic Census.

6.7.1 Estimation of Wholesaler Markups

Based on the regional income statement from the 2012 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 6.6.2. Next, each state in each region was assigned the HARDI regional baseline and incremental markups for the region to which it belongs. Then, DOE assigned all states to one of the nine CBECS 2003 regions used in the analysis and then calculated the population-weighted baseline and incremental markup averages for each region. The results are summarized in Table 6.7.1.

[b] DOE considered a small fraction of residential applications of CWAF.
[c] 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 2009 region 14, was disaggregated into region 30 based on cooling and heating degree days.

Table 6.7.1 Regional Wholesaler Markups for Commercial Warm Air Furnaces in Commercial Applications

CBECS 2003 Regions	Census Divisions	Baseline MU	Incremental MU
1	New England	1.366	1.081
2	Middle Atlantic	1.360	1.091
3	East North Central	1.360	1.099
4	West North Central	1.362	1.099
5	South Atlantic	1.351	1.105
6	East South Central	1.344	1.104
7	West South Central	1.348	1.119
8	Mountain	1.372	1.106
9	Pacific	1.416	1.115

In residential applications, DOE assigned all states to one of the 30 RECS 2009 regions used in the analysis and then calculated population-weighted baseline and incremental markup averages for each region in residential applications. The results are summarized in Table 6.7.2.

Table 6.7.2 Regional Wholesaler Markups for Commercial Warm Air Furnaces in Residential Applications

RECS 2009 Region	State(s)	Baseline MU	Incremental MU
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	1.366	1.081
2	Massachusetts	1.366	1.081
3	New York	1.366	1.081
4	New Jersey	1.351	1.105
5	Pennsylvania	1.354	1.102
6	Illinois	1.362	1.099
7	Indiana, Ohio	1.357	1.099
8	Michigan	1.357	1.099
9	Wisconsin	1.362	1.099
10	Iowa, Minnesota, North Dakota, South Dakota	1.362	1.099
11	Kansas, Nebraska	1.362	1.099
12	Missouri	1.362	1.099
13	Virginia	1.351	1.105
14	Delaware, District of Columbia, Maryland	1.351	1.105
15	Georgia	1.340	1.106
16	North Carolina, South Carolina	1.340	1.106
17	Florida	1.340	1.106
18	Alabama, Kentucky, Mississippi	1.345	1.104
19	Tennessee	1.340	1.106
20	Arkansas, Louisiana, Oklahoma	1.348	1.119
21	Texas	1.348	1.119
22	Colorado	1.362	1.099
23	Idaho, Montana, Utah, Wyoming	1.411	1.113
24	Arizona	1.416	1.115
25	Nevada, New Mexico	1.353	1.118
26	California	1.416	1.115
27	Oregon, Washington	1.416	1.115
28	Alaska	1.416	1.115
29	Hawaii	1.416	1.115
30	West Virginia	1.357	1.099

6.7.2 Estimation of Mechanical Contractor Markups

The 2007 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. By using the equation mentioned in section 6.4.2, DOE was able to estimate baseline markups for each state. Because the Census does not provide more

disaggregated cost data, DOE was not able to differentiate between invariant and variant cost.

Alternatively, DOE calculated the national baseline and incremental markups (Table 6.6.3) and found that the incremental markup is around 20 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. Appendix 6A contains the full set of data.

To estimate the baseline and incremental markups for both replacement and new construction markets and also for small and large mechanical contractors for each state, DOE applied the size and market modifier (*i.e.*, 15.3 percent higher for the small contractor in the replacement market; 9.5 percent higher for the small contractor in the new construction market; 0.6 percent higher for the large contractor in replacement market; 5.2 percent lower for the large contractor in new construction market) derived in section 6.6.3.4 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 nine CBECS 2003 regions and then calculated the population-weighted average baseline and incremental markups for small and large mechanical contractors for each region, as shown in Table 6.7.3 and Table 6.7.4.

Table 6.7.3 Population-Weighted Small Mechanical Contractor Markups for Commercial Warm Air Furnaces in Commercial Application

CBECS 2003 Regions	Census Divisions	Replacement Baseline MU	Replacement Incremental MU	New Construction Baseline MU	New Construction Incremental MU
1	New England	1.716	1.373	1.620	1.296
2	Middle Atlantic	1.728	1.382	1.631	1.304
3	East North Central	1.721	1.376	1.624	1.299
4	West North Central	1.661	1.329	1.568	1.254
5	South Atlantic	1.670	1.336	1.576	1.261
6	East South Central	1.671	1.337	1.577	1.262
7	West South Central	1.674	1.339	1.579	1.264
8	Mountain	1.701	1.361	1.606	1.284
9	Pacific	1.783	1.426	1.683	1.346

Table 6.7.4 Population-Weighted Large Mechanical Contractor Markups for Commercial Warm Air Furnaces in Commercial Application

CBECS 2003 Regions	Census Divisions	Replacement Baseline MU	Replacement Incremental MU	New Construction Baseline MU	New Construction Incremental MU
1	New England	1.488	1.191	1.405	1.124
2	Middle Atlantic	1.498	1.198	1.414	1.131
3	East North Central	1.492	1.194	1.408	1.126
4	West North Central	1.441	1.152	1.360	1.088
5	South Atlantic	1.448	1.158	1.366	1.093
6	East South Central	1.449	1.159	1.368	1.094
7	West South Central	1.451	1.161	1.370	1.096
8	Mountain	1.475	1.180	1.392	1.114
9	Pacific	1.546	1.237	1.459	1.167

In residential applications, DOE divided all states among the 30 RECS 2009 regions and then calculated population-weighted average baseline and incremental markups for mechanical contractors for each region, as shown in Table 6.7.5.

Table 6.7.5 Population-Weighted Mechanical Contractor Markups for Commercial Warm Air Furnaces in Residential Application

RECS 2009 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	1.548	1.238	1.461	1.169
2	Massachusetts	1.527	1.222	1.441	1.153
3	New York	1.589	1.271	1.499	1.200
4	New Jersey	1.572	1.258	1.484	1.187
5	Pennsylvania	1.468	1.174	1.385	1.108
6	Illinois	1.566	1.252	1.478	1.182
7	Indiana, Ohio	1.552	1.241	1.464	1.171
8	Michigan	1.519	1.215	1.433	1.147
9	Wisconsin	1.499	1.199	1.414	1.131
10	Iowa, Minnesota, North Dakota, South Dakota	1.519	1.215	1.434	1.147
11	Kansas, Nebraska	1.449	1.159	1.367	1.094
12	Missouri	1.468	1.175	1.386	1.109
13	Virginia	1.546	1.237	1.459	1.167
14	Delaware, District of Columbia, Maryland	1.479	1.184	1.396	1.117
15	Georgia	1.463	1.170	1.381	1.105
16	North Carolina, South Carolina	1.490	1.192	1.406	1.125
17	Florida	1.501	1.201	1.417	1.134
18	Alabama, Kentucky, Mississippi	1.515	1.212	1.429	1.144
19	Tennessee	1.466	1.173	1.384	1.107
20	Arkansas, Louisiana, Oklahoma	1.531	1.225	1.445	1.156
21	Texas	1.487	1.190	1.404	1.123
22	Colorado	1.520	1.216	1.434	1.147
23	Idaho, Montana, Utah, Wyoming	1.480	1.184	1.397	1.117
24	Arizona	1.569	1.255	1.481	1.184
25	Nevada, New Mexico	1.525	1.220	1.440	1.152
26	California	1.595	1.276	1.506	1.204
27	Oregon, Washington	1.568	1.254	1.480	1.184
28	Alaska	1.753	1.402	1.654	1.324
29	Hawaii	1.822	1.458	1.720	1.376
30	West Virginia	1.517	1.214	1.432	1.145

6.7.3 Estimation of General Contractor Markups

To derive regional general contractor markups for the commercial building construction sector from the 2007 Economic Census, DOE used the Commercial Building Construction series (NAICS 236220) from the 2007 Economic Census to derive regional general contractor markups for the commercial application of CWAF. Similarly, DOE used the Residential Building Construction series (NAICS 236110) from the 2007 Economic Census to derive regional general contractor markups for the residential application of CWAF.

Each series consists of statewide cost data required to calculate baseline markups for each state, as illustrated in section 6.4.2. Although there is only a new construction (no replacement) channel for general contractors, the same technique shown for mechanical contractors was employed to estimate regional baseline and incremental markups. First, DOE estimated the statewide incremental markups by applying the ratio of national baseline and incremental markups (*i.e.*, the national incremental markup is around 8.84 and 9.16 percent lower than the national baseline markup in residential and commercial application, respectively) to the baseline markups for each state. Lastly, DOE divided all states among the nine CBECS 2003 regions and the 30 RECS 2009 regions; then calculated the population-weighted average baseline and incremental markups for general contractors for each region in both commercial and residential application. The final results are summarized in Table 6.7.6 for commercial application and Table 6.7.7 for residential application (Appendix 6A contains the full set of data.)

Table 6.7.6 Population-Weighted General Contractor Markups for Commercial Warm Air Furnaces in Commercial Application

CBECS 2003 Regions	Census Division	Baseline MU	Incremental MU
1	New England	1.336	1.214
2	Middle Atlantic	1.418	1.288
3	East North Central	1.314	1.194
4	West North Central	1.283	1.165
5	South Atlantic	1.342	1.219
6	East South Central	1.331	1.209
7	West South Central	1.314	1.194
8	Mountain	1.266	1.150
9	Pacific	1.319	1.198

Table 6.7.7 Population-Weighted General Contractor Markups for Commercial Warm Air Furnaces in Residential Application

RECS 2009 Regions	State(s)	Baseline MU	Incremental MU
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	1.411	1.277
2	Massachusetts	1.343	1.216
3	New York	1.393	1.261
4	New Jersey	1.503	1.361
5	Pennsylvania	1.362	1.233
6	Illinois	1.589	1.438
7	Indiana, Ohio	1.378	1.248
8	Michigan	1.537	1.392
9	Wisconsin	1.340	1.213
10	Iowa, Minnesota, North Dakota, South Dakota	1.368	1.238
11	Kansas, Nebraska	1.351	1.223
12	Missouri	1.325	1.200
13	Virginia	1.450	1.313
14	Delaware, District of Columbia, Maryland	1.418	1.284
15	Georgia	1.428	1.293
16	North Carolina, South Carolina	1.390	1.258
17	Florida	1.528	1.384
18	Alabama, Kentucky, Mississippi	1.355	1.227
19	Tennessee	1.353	1.225
20	Arkansas, Louisiana, Oklahoma	1.373	1.243
21	Texas	1.499	1.357
22	Colorado	1.499	1.357
23	Idaho, Montana, Utah, Wyoming	1.308	1.185
24	Arizona	1.707	1.546
25	Nevada, New Mexico	1.639	1.484
26	California	1.717	1.555
27	Oregon, Washington	1.465	1.326
28	Alaska	1.854	1.678
29	Hawaii	1.417	1.283
30	West Virginia	1.545	1.398

6.8 SALES TAX

The sales tax represents state and local sales taxes that are applied to the customer price of the equipment. The sales tax is a multiplicative factor that increases the customer equipment price. DOE only applied the sales tax to the customer price of the equipment in the replacement market, not the new construction market. The common practice for selling commercial

appliances like CWAF 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 the customers. Therefore, no additional sales tax is necessary to calculate the customer equipment price for the new construction market.

DOE derived state and local taxes from data provided by the Sales Tax Clearinghouse.[14] These data represent weighted averages that include county and city rates. DOE then derived the population-weighted average tax values for each CBECS 2003 and RECS 2009 region to align with the regional markups for wholesalers and mechanical and general contractors, as shown in Table 6.8.1 and Table 6.8.2. Detailed sales tax data by each state can be found in appendix 6A.

Table 6.8.1 Average Sales Tax Rates by CBECS 2003 Region

CBECS 2003 Regions	Census Divisions	2019 Population	Tax Rate (2013) %
1	New England	14,983,132	5.65
2	Middle Atlantic	42,255,762	7.48
3	East North Central	47,208,749	6.90
4	West North Central	21,653,562	7.08
5	South Atlantic	66,011,197	6.48
6	East South Central	19,280,661	8.03
7	West South Central	41,153,178	8.16
8	Mountain	24,648,296	6.46
9	Pacific	54,689,449	7.66
Population-Weighted National Average			**7.16**

Table 6.8.2 Average Sales Tax Rates by RECS 2009 Region

RECS 2009 Region	State(s)	2019 Population	Tax Rate (2013) %
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	7,991,852	5.12
2	Massachusetts	6,991,279	6.25
3	New York	20,223,045	8.40
4	New Jersey	9,125,883	6.95
5	Pennsylvania	12,906,835	6.40
6	Illinois	12,955,324	8.05
7	Indiana, Ohio	18,428,432	7.03
8	Michigan	9,970,197	6.00
9	Wisconsin	5,854,796	5.45
10	Iowa, Minnesota, North Dakota, South Dakota	10,575,015	6.84
11	Kansas, Nebraska	4,918,225	7.15
12	Missouri	6,160,322	7.45
13	Virginia	8,732,698	5.60
14	Delaware, District of Columbia, Maryland	7,948,365	5.26
15	Georgia	10,614,452	7.10
16	North Carolina, South Carolina	15,560,791	7.00
17	Florida	21,305,945	6.65
18	Alabama, Kentucky, Mississippi	12,470,494	7.25
19	Tennessee	6,810,167	9.45
20	Arkansas, Louisiana, Oklahoma	11,857,951	8.67
21	Texas	29,295,227	7.95
22	Colorado	5,774,047	6.10
23	Idaho, Montana, Utah, Wyoming	6,572,023	5.33
24	Arizona	7,163,999	7.15
25	Nevada, New Mexico	5,138,227	7.34
26	California	40,783,102	8.45
27	Oregon, Washington	11,644,007	5.73
28	Alaska	767,664	1.35
29	Hawaii	1,494,676	4.40
30	West Virginia	1,848,946	6.05
Population-Weighted National Average			**7.16**

6.9 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 6.9.1).

DOE used the overall baseline markup to estimate the customer equipment price of baseline models, given the manufacturer cost of the baseline models. As stated previously, DOE

considers baseline models to be equipment 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 equipment 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. 6.1

Where:

CPP_{BASE} = customer equipment 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 customer equipment price, given changes in the manufacturer cost from the baseline model cost resulting from an energy conservation standard to raise equipment energy efficiency. The total customer equipment price for more energy-efficient models is composed of two components: the customer equipment price of the baseline model and the change in customer equipment 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 customer equipment 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. 6.2

Where:

CPP_{STD} = customer equipment price for models meeting new energy conservation standards,
CPP_{BASE} = customer equipment 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 average baseline and incremental markups for each market participant are summarized in Table 6.9.1 and Table 6.9.2 for CWAF. Based on CWAF shipment forecasts for the year 2019 (see chapter 9), DOE estimated that 20 percent of gas-fired CWAF and 5 percent of oil-fired CWAF go to new construction. On the other hand, 80 percent of gas-fired CWAF and 95 percent of oil-fired CWAF go to the replacement market. By weighting the markups by the market shares for each CWAF equipment class and market, DOE calculated the total markups listed in Table 6.9.3.

Table 6.9.1 Summary of Overall Markups on Commercial Warm Air Furnaces in Commercial Applications

	Replacement			New Construction		
	Baseline Markup	**Incremental Markup**	**National Account: Baseline/ Incr. MU**	**Baseline Markup**	**Incremental Markup**	**National Account: Baseline/ Incr. MU**
Gas-fired CWAF						
Manufacturer	1.31			1.31		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.61	1.12/1.29	
General Contractor (Commercial Building)	--	--		1.31	1.19	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	3.22	2.10	2.03/1.50	3.76	2.21	2.28/1.55
Oil-fired CWAF						
Manufacturer	1.28			1.28		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.61	1.12/1.29	
General Contractor (Commercial Building)	--	--		1.31	1.19	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	3.15	2.05	2.00/1.47	3.67	2.16	2.24/1.53

Table 6.9.2 Summary of Overall Markups on Commercial Warm Air Furnaces in Residential Applications

	Replacement			New Construction		
	Baseline Markup	**Incremental Markup**	**National Account: Baseline/ Incr. MU**	**Baseline Markup**	**Incremental Markup**	**National Account: Baseline/ Incr. MU**
Gas-fired CWAF						
Manufacturer	1.31			1.31		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.61	1.12/1.29	
General Contractor (Residential Building)	--	--		1.47	1.34	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	2.82	1.83	2.03/1.50	3.24	1.92	2.50/1.80
Oil-fired CWAF						
Manufacturer	1.28			1.28		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.16	1.12/1.29	
General Contractor (Residential Building)	--	--		1.47	1.34	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	2.76	1.79	2.00/1.47	3.17	1.88	2.45/1.77

Table 6.9.3 Summary of Markup by Commercial Warm Air Furnace Equipment Class

Equipment Class	Baseline Markup	Incremental Markup
Gas-fired CWAF	2.96	1.92
Oil-fired CWAF	2.84	1.85

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APPENDIX 6A. DETAILED DATA FOR EQUIPMENT PRICE MARKUPS

TABLE OF CONTENTS

6A.1 DETAILED WHOLESALER COST DATA 6A-1
6A.2 DETAILED MECHANICAL CONTRACTOR COST DATA..... 6A-2
6A.3 DETAILED GENERAL CONTRACTOR COST DATA..... 6A-4
6A.4 ESTIMATION OF CONTRACTOR MARKUP BY STATE..... 6A-6
6A.5 STATE SALES TAX RATES 6A-13

LIST OF TABLES

Table 6A.1.1 Disaggregated Costs and Expenses for Wholesalers 6A-1
Table 6A.2.1 Mechanical Contractor Expenses and Markups Used To Scale the Incremental Markups 6A-3
Table 6A.3.1 Commercial Building General Contractor Expenses and Markups..... 6A-4
Table 6A.3.2 Residential Building General Contractor Expenses and Markups..... 6A-5
Table 6A.4.1 Small Mechanical Contractor Markup Estimation by State, 2007 ..... 6A-6
Table 6A.4.2 Large Mechanical Contractor Markup Estimation by State, 2007 ..... 6A-7
Table 6A.4.3 Commercial Building General Contractor Baseline Markups by State.... 6A-10
Table 6A.4.4 Residential Building General Contractor Baseline Markups by State..... 6A-11
Table 6A.5.1 State Sales Tax Rates 6A-13

APPENDIX 6A. DETAILED DATA FOR EQUIPMENT PRICE MARKUPS

6A.1 DETAILED WHOLESALER COST DATA

Based on data provided by the Heating Air-conditioning & Refrigeration Distributors International (HARDI), 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. 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	**73.7**	
Gross Margin	**26.3**	
Payroll Expenses	**15.1**	Baseline
Executive Salaries & Bonuses	1.7	
Branch Manager Salaries and Commissions	1.5	
Sales Executive Salaries & Commissions	0.5	
Outside Sales Salaries & Commissions	2.1	
Inside/Counter Sales/Wages	2.8	
Purchasing Salaries/Wages	0.4	
Credit Salaries/Wages	0.2	
IT Salaries/Wages	0.1	
Warehouse Salaries/Wages	1.4	
Accounting	0.5	
Delivery Salaries/Wages	0.7	
All Other Salaries/Wages & Bonuses	0.8	
Payroll Taxes	1.0	
Group Insurance	1.1	
Benefit Plans	0.3	
Occupancy Expenses	**3.6**	Baseline
Utilities: Heat, Light, Power, Water	0.4	
Telephone	0.3	
Building Repairs & Maintenance	0.2	
Rent or Ownership in Real Estate	2.7	

Item	Percent of Revenue %	Scaling
Other Operating Expenses	**5.5**	Baseline & Incremental
Sales Expenses (incl. advertising & promotion)	0.9	
Insurance (business liability & casualty)	0.2	
Depreciation	0.4	
Vehicle Expenses	1.4	
Personal Property Taxes/Licenses	0.1	
Collection Expenses	0.3	
Bad Debt Losses	0.2	
Data Processing	0.3	
All Other Operating Expenses	1.7	
Total Operating Expenses	**24.2**	
Operating Profit	**2.1**	Baseline & Incremental
Other Income	0.4	
Interest Expense	0.5	
Other Non-operating Expenses	0.0	
Profit Before Taxes	**2.0**	

Source: Heating, Air-conditioning & Refrigeration Distributors International. 2012. 2012 Profit Report (2011 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 COST 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 are shown in Table 6A.2.1 by both dollar value and percentage terms from the 2007 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	**107,144,428**	**67.80**	
Total payroll, construction workers wages	31,373,558	19.85	
Cost of materials, components, and supplies	59,023,964	37.35	
Cost of construction work subcontracted out to others	13,646,192	8.63	
Total cost of selected power, fuels, and lubricants	3,100,714	1.96	
Gross Margin	**50,895,129**	**32.20**	
Payroll Expenses	**28,065,632**	**17.76**	
Total payroll, other employee wages	14,041,336	8.88	
Total fringe benefits	13,585,040	8.60	Baseline
Temporary staff and leased employee expenses	439,256	0.28	
Occupancy Expenses	**3,436,208**	**2.17**	
Rental costs of machinery and equipment	1,047,026	0.66	
Rental costs of buildings	1,231,263	0.78	Baseline
Communication services	640,851	0.41	
Cost of repair to machinery and equipment	517,068	0.33	
Other Operating Expenses	**12,671,194**	**8.02**	
Purchased professional and technical services	843,641	0.53	
Data processing and other purchased computer services	98,016	0.06	
Expensed computer hardware and other equipment	255,474	0.16	
Expensed purchases of software	64,195	0.04	Baseline & Incremental
Advertising and promotion services	1,018,265	0.64	
All other expenses	6,944,674	4.39	
Refuse removal (including hazardous waste) services	153,241	0.10	
Taxes and license fees	996,138	0.63	
Total depreciation ($1,000)	2,297,550	1.45	
Net Profit Before Income Taxes	**6,722,095**	**4.25**	Baseline & Incremental

Source: U.S. Census Bureau. 2007. Plumbing, Heating, and Air-Conditioning Contractors: 2007. Sector 23: 238220. Construction: Geographic Area Series. Detailed Statistics for Establishments: 2007.
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

Table 6A.3.1 and Table 6A.3.2 show the complete breakdown of costs and expenses of commercial and 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 equipment costs.

Table 6A.3.1 Commercial Building General Contractor Expenses and Markups

Item	Dollar Value *$1,000*	Percentage %	Scaling
Total Cost of Equipment Sales	**250,657,006**	**76.24**	
Total payroll, construction workers wages	16,449,830	5.00	
Cost of materials, components, and supplies	74,148,280	22.55	
Cost of construction work subcontracted out to others	157,873,840	48.02	
Total cost of selected power, fuels, and lubricants	2,185,056	0.66	
Gross Margin	**78,113,967**	**23.76**	
Payroll Expenses	**25,948,454**	**7.89**	Baseline
Total payroll, other employees' wages	16,652,791	5.07	
Total fringe benefits	8,666,079	2.64	
Temporary staff and leased employee expenses	629,584	0.19	
Occupancy Expenses	**3,301,046**	**1.00**	Baseline
Rental costs of machinery and equipment	1,403,979	0.43	
Rental costs of buildings	1,045,163	0.32	
Communication services	385,109	0.12	
Cost of repair to machinery and equipment	466,795	0.14	
Other Operating Expenses	**10,770,620**	**3.28**	Baseline & Incremental
Purchased professional and technical services	1,121,644	0.34	
Data processing and other purchased computer services	127,031	0.04	
Expensed computer hardware and other equipment	219,601	0.07	
Expensed purchases of software	67,977	0.02	
Advertising and promotion services	290,239	0.09	
All other expenses	6,321,197	1.92	
Refuse removal (including hazardous waste) services	233,831	0.07	
Taxes and license fees	807,872	0.25	
Total depreciation ($1,000)	1,581,228	0.48	
Net Profit Before Income Taxes	**38,093,847**	**11.59**	Baseline & Incremental

Source: U.S. Census Bureau. 2007. Residential Building Construction. Sector 23, EC0723I1: 236220 (Commercial Building Construction. Construction, Industry Series, Preliminary Detailed Statistics for Establishments: 2007.
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 Residential Building General Contractor Expenses and Markups

Item	Dollar Value *$1,000*	Percentage %	Scaling
Total Cost of Equipment Sales	**238,431,389**	**67.55**	
Total payroll, construction workers wages	16,629,321	4.71	
Cost of materials, components, and supplies	126,764,975	35.91	
Cost of construction work subcontracted out to others	90,956,668	25.77	
Total cost of selected power, fuels, and lubricants	4,080,425	1.16	
Gross Margin	**114,558,247**	**32.45**	
Payroll Expenses	**28,806,792**	**8.16**	Baseline
Total payroll, other employee wages	20,843,029	5.90	
Total fringe benefits	7,464,670	2.11	
Temporary staff and leased employee expenses	499,093	0.14	
Occupancy Expenses	**3,558,796**	1.01	Baseline
Rental costs of machinery and equipment	572,783	0.16	
Rental costs of buildings	1,532,841	0.43	
Communication services	810,436	0.23	
Cost of repair to machinery and equipment	642,736	0.18	
Other Operating Expenses	**21,341,175**	**6.05**	Baseline & Incremental
Purchased professional and technical services	1,834,816	0.52	
Data processing and other purchased computer services	141,344	0.04	
Expensed computer hardware and other equipment	261,701	0.07	
Expensed purchases of software	105,338	0.03	
Advertising and promotion services	2,544,687	0.72	
All other expenses	10,840,757	3.07	
Refuse removal (including hazardous waste) services	520,907	0.15	
Taxes and license fees	1,791,539	0.51	
Total depreciation ($1,000)	3,300,086	0.93	
Net Profit Before Income Taxes	**60,851,484**	**17.24**	Baseline & Incremental

Source: U.S. Census Bureau. 2007. Residential Building Construction. Sector 236110, Industry Series, Preliminary Detailed Statistics for Establishments: 2007.

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.

6A.4 ESTIMATION OF CONTRACTOR MARKUP BY STATE

Table 6A.4.1 Small Mechanical Contractor Markup Estimation by State, 2007

State	Value of Const. *$1,000*	Cost of Goods Sold *$1,000*	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
Alabama	2,010,305	1,401,223	1.435	1.148	1.654	1.323	1.571	1.257
Alaska	583,171	344,729	1.692	1.353	1.951	1.560	1.852	1.482
Arizona	3,522,116	2,326,475	1.514	1.211	1.746	1.396	1.658	1.326
Arkansas	1,065,754	743,395	1.434	1.147	1.653	1.322	1.570	1.256
California	16,726,969	10,865,201	1.539	1.232	1.775	1.420	1.686	1.349
Colorado	3,056,988	2,084,454	1.467	1.173	1.691	1.353	1.606	1.285
Connecticut	1,704,668	1,135,871	1.501	1.201	1.730	1.384	1.643	1.315
Delaware	481,900	D	1.421	1.137	1.638	1.311	1.556	1.245
District of Columbia	34,600	D	1.458	1.167	1.681	1.345	1.597	1.277
Florida	9,061,426	6,254,391	1.449	1.159	1.670	1.336	1.586	1.269
Georgia	4,700,799	3,329,842	1.412	1.129	1.628	1.302	1.546	1.237
Hawaii	800,221	455,122	1.758	1.407	2.027	1.622	1.925	1.540
Idaho	900,698	617,165	1.459	1.168	1.683	1.346	1.598	1.278
Illinois	7,641,642	5,058,047	1.511	1.209	1.742	1.394	1.654	1.323
Indiana	4,002,323	2,605,238	1.536	1.229	1.771	1.417	1.682	1.346
Iowa	1,868,483	1,305,883	1.431	1.145	1.650	1.320	1.567	1.253
Kansas	1,395,359	966,707	1.443	1.155	1.664	1.331	1.581	1.264
Kentucky	1,747,925	1,157,360	1.510	1.208	1.741	1.393	1.654	1.323
Louisiana	1,997,044	1,317,429	1.516	1.213	1.748	1.398	1.660	1.328
Maine	580,816	394,847	1.471	1.177	1.696	1.357	1.611	1.289
Maryland	5,329,135	3,739,560	1.425	1.140	1.643	1.314	1.560	1.248
Massachusetts	4,099,301	2,781,377	1.474	1.179	1.699	1.359	1.614	1.291
Michigan	4,420,638	3,015,948	1.466	1.173	1.690	1.352	1.605	1.284
Minnesota	3,402,921	2,315,330	1.470	1.176	1.695	1.356	1.609	1.287
Mississippi	1,025,452	715,571	1.433	1.146	1.652	1.322	1.569	1.255
Missouri	3,335,124	2,353,598	1.417	1.134	1.634	1.307	1.552	1.241
Montana	483,578	345,458	1.400	1.120	1.614	1.291	1.533	1.226
Nebraska	1,004,296	755,338	1.330	1.064	1.533	1.226	1.456	1.165
Nevada	2,327,842	1,600,555	1.454	1.164	1.677	1.342	1.593	1.274
New Hampshire	620,761	D	1.472	1.178	1.697	1.358	1.612	1.289
New Jersey	5,062,336	3,337,013	1.517	1.214	1.749	1.399	1.661	1.329
New Mexico	891,914	595,659	1.497	1.198	1.726	1.381	1.640	1.312

State	Value of Const. *$1,000*	Cost of Goods Sold *$1,000*	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
New York	10,364,779	6,760,337	1.533	1.227	1.768	1.414	1.679	1.343
North Carolina	5,111,396	3,631,802	1.407	1.126	1.623	1.298	1.541	1.233
North Dakota	360,683	255,057	1.414	1.131	1.630	1.304	1.548	1.239
Ohio	5,618,591	3,809,806	1.475	1.180	1.700	1.360	1.615	1.292
Oklahoma	1,352,943	924,264	1.464	1.171	1.688	1.350	1.603	1.282
Oregon	1,893,678	1,237,956	1.530	1.224	1.764	1.411	1.675	1.340
Pennsylvania	6,487,476	4,579,367	1.417	1.133	1.633	1.307	1.551	1.241
Rhode Island	631,202	410,653	1.537	1.230	1.772	1.418	1.683	1.346
South Carolina	1,991,303	1,326,690	1.501	1.201	1.731	1.384	1.644	1.315
South Dakota	386,186	239,017	1.616	1.293	1.863	1.490	1.769	1.415
Tennessee	2,595,613	1,834,242	1.415	1.132	1.632	1.305	1.550	1.240
Texas	10,810,308	7,532,064	1.435	1.148	1.655	1.324	1.572	1.257
Utah	1,746,398	1,235,004	1.414	1.131	1.630	1.304	1.548	1.239
Vermont	294,806	D	1.472	1.178	1.697	1.358	1.612	1.289
Virginia	4,623,151	3,099,329	1.492	1.193	1.720	1.376	1.633	1.307
Washington	4,111,543	2,734,093	1.504	1.203	1.734	1.387	1.647	1.317
West Virginia	655,100	D	1.464	1.171	1.688	1.350	1.603	1.282
Wisconsin	2,926,545	2,023,634	1.446	1.157	1.667	1.334	1.584	1.267
Wyoming	289,391	198,105	1.461	1.169	1.684	1.347	1.600	1.280

Sources: U.S. Bureau of the Census. American Factfinder: 2007. Sector 23: Plumbing, Heating, and Air-Conditioning Contractors (NAICS 238220), Detailed Statistics for Establishments: 2007
http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ECN_2007_US_23I1&prodType=table and
Geographic Area Series: Detailed Statistics for Establishments: 2007.
Notes: The Census Bureau withheld data for some states, as indicated by the entry "D".
Markups may vary across states for several reasons, including differences in firm size.
Due to sample size and/or magnitude of reporting error relative to the mean, disaggregated information not provided for all of the Subcontract, Materials, and Fuels fields. In these cases, the state markup ratio is calculated as an average of neighboring states (*ex*. Delaware, District of Columbia, New Hampshire, Vermont, and West Virginia)

Table 6A.4.2 Large Mechanical Contractor Markup Estimation by State, 2007

State	Value of Const. *$1,000*	Cost of Goods Sold *$1,000*	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
Alabama	2,010,305	1,401,223	1.435	1.148	1.443	1.155	1.360	1.088
Alaska	583,171	344,729	1.692	1.353	1.702	1.361	1.604	1.283
Arizona	3,522,116	2,326,475	1.514	1.211	1.523	1.218	1.435	1.148
Arkansas	1,065,754	743,395	1.434	1.147	1.442	1.154	1.359	1.087
California	16,726,969	10,865,201	1.539	1.232	1.549	1.239	1.459	1.168

State	Value of Const. *$1,000*	Cost of Goods Sold *$1,000*	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
Colorado	3,056,988	2,084,454	1.467	1.173	1.475	1.180	1.390	1.112
Connecticut	1,704,668	1,135,871	1.501	1.201	1.510	1.208	1.423	1.138
Delaware	481,900	D	1.421	1.137	1.430	1.144	1.347	1.078
District of Columbia	34,600	D	1.458	1.167	1.467	1.173	1.382	1.106
Florida	9,061,426	6,254,391	1.449	1.159	1.458	1.166	1.373	1.099
Georgia	4,700,799	3,329,842	1.412	1.129	1.420	1.136	1.338	1.071
Hawaii	800,221	455,122	1.758	1.407	1.769	1.415	1.667	1.333
Idaho	900,698	617,165	1.459	1.168	1.468	1.175	1.384	1.107
Illinois	7,641,642	5,058,047	1.511	1.209	1.520	1.216	1.432	1.146
Indiana	4,002,323	2,605,238	1.536	1.229	1.545	1.236	1.456	1.165
Iowa	1,868,483	1,305,883	1.431	1.145	1.439	1.152	1.356	1.085
Kansas	1,395,359	966,707	1.443	1.155	1.452	1.162	1.368	1.095
Kentucky	1,747,925	1,157,360	1.510	1.208	1.519	1.215	1.432	1.145
Louisiana	1,997,044	1,317,429	1.516	1.213	1.525	1.220	1.437	1.150
Maine	580,816	394,847	1.471	1.177	1.480	1.184	1.394	1.116
Maryland	5,329,135	3,739,560	1.425	1.140	1.434	1.147	1.351	1.081
Massachusetts	4,099,301	2,781,377	1.474	1.179	1.483	1.186	1.397	1.118
Michigan	4,420,638	3,015,948	1.466	1.173	1.475	1.180	1.390	1.112
Minnesota	3,402,921	2,315,330	1.470	1.176	1.479	1.183	1.393	1.115
Mississippi	1,025,452	715,571	1.433	1.146	1.442	1.153	1.359	1.087
Missouri	3,335,124	2,353,598	1.417	1.134	1.426	1.140	1.343	1.075
Montana	483,578	345,458	1.400	1.120	1.408	1.127	1.327	1.062
Nebraska	1,004,296	755,338	1.330	1.064	1.338	1.070	1.260	1.008
Nevada	2,327,842	1,600,555	1.454	1.164	1.463	1.170	1.379	1.103
New Hampshire	620,761	D	1.472	1.178	1.481	1.185	1.395	1.116
New Jersey	5,062,336	3,337,013	1.517	1.214	1.526	1.221	1.438	1.151
New Mexico	891,914	595,659	1.497	1.198	1.506	1.205	1.419	1.136
New York	10,364,779	6,760,337	1.533	1.227	1.542	1.234	1.453	1.163
North Carolina	5,111,396	3,631,802	1.407	1.126	1.416	1.133	1.334	1.067
North Dakota	360,683	255,057	1.414	1.131	1.423	1.138	1.341	1.072
Ohio	5,618,591	3,809,806	1.475	1.180	1.484	1.187	1.398	1.118
Oklahoma	1,352,943	924,264	1.464	1.171	1.473	1.178	1.388	1.110
Oregon	1,893,678	1,237,956	1.530	1.224	1.539	1.231	1.450	1.160
Pennsylvania	6,487,476	4,579,367	1.417	1.133	1.425	1.140	1.343	1.074

State	Value of Const. *$1,000*	Cost of Goods Sold *$1,000*	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
Rhode Island	631,202	410,653	1.537	1.230	1.546	1.237	1.457	1.166
South Carolina	1,991,303	1,326,690	1.501	1.201	1.510	1.208	1.423	1.138
South Dakota	386,186	239,017	1.616	1.293	1.625	1.300	1.532	1.225
Tennessee	2,595,613	1,834,242	1.415	1.132	1.424	1.139	1.342	1.073
Texas	10,810,308	7,532,064	1.435	1.148	1.444	1.155	1.361	1.088
Utah	1,746,398	1,235,004	1.414	1.131	1.423	1.138	1.341	1.072
Vermont	294,806	D	1.472	1.178	1.481	1.185	1.395	1.116
Virginia	4,623,151	3,099,329	1.492	1.193	1.501	1.200	1.414	1.131
Washington	4,111,543	2,734,093	1.504	1.203	1.513	1.210	1.426	1.140
West Virginia	655,100	D	1.464	1.171	1.473	1.178	1.388	1.110
Wisconsin	2,926,545	2,023,634	1.446	1.157	1.455	1.164	1.371	1.097
Wyoming	289,391	198,105	1.461	1.169	1.470	1.176	1.385	1.108

Sources: U.S. Bureau of the Census. American Factfinder: 2007. Sector 23: Plumbing, Heating, and Air-Conditioning Contractors (NAICS 238220), Detailed Statistics for Establishments: 2007
http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ECN_2007_US_23I1&prodType=table and
Geographic Area Series: Detailed Statistics for Establishments: 2007.
Notes: The Census Bureau withheld data for some states, as indicated by the entry "D".
Markups may vary across states for several reasons, including differences in firm size.
Due to sample size and/or magnitude of reporting error relative to the mean, disaggregated information not provided for all of the Subcontract, Materials, and Fuels fields. In these cases, the state markup ratio is calculated as an average of neighboring states (*ex*. Delaware, District of Columbia, New Hampshire, Vermont, and West Virginia)

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	7,553,561	5,966,033	1.266	1.266
Alaska	1,687,503	1,265,663	1.333	1.333
Arizona	12,151,583	9,218,504	1.318	1.318
Arkansas	3,187,913	2,524,259	1.263	1.263
California	43,866,759	32,549,870	1.348	1.348
Colorado	9,218,679	7,554,813	1.220	1.220
Connecticut	2,398,913	1,704,640	1.407	1.407
Delaware	727,553	508,123	1.432	1.432
District of Columbia	918,723	792,275	1.160	1.160
Florida	19,686,238	14,553,102	1.353	1.353
Georgia	10,541,824	7,189,660	1.466	1.466
Hawaii	2,341,014	1,802,494	1.299	1.299
Idaho	1,555,058	1,291,347	1.204	1.204
Illinois	13,909,785	10,206,749	1.363	1.363
Indiana	5,967,203	4,636,748	1.287	1.287
Iowa	3,405,782	2,585,432	1.317	1.317
Kansas	2,721,025	2,252,824	1.208	1.208
Kentucky	3,028,131	2,289,475	1.323	1.323
Louisiana	4,476,198	3,078,813	1.454	1.454
Maine	738,455	585,867	1.260	1.260
Maryland	8,299,684	6,472,850	1.282	1.282
Massachusetts	7,035,875	5,272,385	1.334	1.334
Michigan	5,363,993	3,824,364	1.403	1.403
Minnesota	8,203,910	5,908,604	1.388	1.388
Mississippi	3,593,463	2,094,843	1.715	1.715
Missouri	9,293,483	7,970,536	1.166	1.166
Montana	924,342	734,797	1.258	1.258
Nebraska	1,589,168	1,080,612	1.471	1.471
Nevada	6,285,128	4,704,160	1.336	1.336
New Hampshire	1,040,005	816,281	1.274	1.274
New Jersey	7,331,413	4,421,279	1.658	1.658
New Mexico	1,537,718	1,210,550	1.270	1.270
New York	19,752,366	14,491,190	1.363	1.363
North Carolina	8,605,888	6,566,496	1.311	1.311
North Dakota	659,818	542,850	1.215	1.215
Ohio	8,889,511	7,158,247	1.242	1.242

State	Value of Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Oklahoma	3,307,370	2,875,301	1.150	1.150
Oregon	3,273,641	2,606,128	1.256	1.256
Pennsylvania	11,676,721	8,744,986	1.335	1.335
Rhode Island	847,621	627,945	1.350	1.350
South Carolina	3,532,858	2,885,636	1.224	1.224
South Dakota	912,508	757,264	1.205	1.205
Tennessee	7,004,112	5,784,562	1.211	1.211
Texas	26,821,716	20,332,044	1.319	1.319
Utah	3,141,938	2,604,471	1.206	1.206
Vermont	445,373	367,539	1.212	1.212
Virginia	8,926,148	6,759,203	1.321	1.321
Washington	9,936,986	8,276,568	1.201	1.201
West Virginia	563,473	424,942	1.326	1.326
Wisconsin	7,248,667	5,891,541	1.230	1.230
Wyoming	432,812	349,769	1.237	1.237

Sources: U.S. Bureau of the Census, American Factfinder. 2007 Economic Census. Sector 23: Subsectors 236220 (Commercial Building Construction). Sector 23: EC0723A1: Construction: Geographic Area Series: Detailed Statistics for Establishments: 2007.
Notes: The Census Bureau withheld data for some states, as indicated by the entry "D".

Table 6A.4.4 Residential Building General Contractor Baseline Markups by State

State	Value of Residential Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Alabama	4,232,349	3,106,308	1.363	1.234
Alaska	598,572	322,897	1.854	1.678
Arizona	14,743,264	8,636,727	1.707	1.546
Arkansas	821,493	638,546	1.287	1.165
California	49,325,592	28,727,843	1.717	1.555
Colorado	9,711,667	6,478,218	1.499	1.357
Connecticut	2,835,015	1,914,706	1.481	1.341
Delaware	912,121	714,609	1.276	1.156
District of Columbia	177,004	115,545	1.532	1.387
Florida	33,290,091	21,780,175	1.528	1.384
Georgia	12,492,752	8,745,668	1.428	1.293
Hawaii	2,739,122	1,933,143	1.417	1.283
Idaho	2,565,176	2,014,522	1.273	1.153
Illinois	13,035,923	8,206,105	1.589	1.438
Indiana	4,637,976	3,418,576	1.357	1.228
Iowa	1,846,602	1,449,114	1.274	1.154
Kansas	1,940,745	1,443,265	1.345	1.217

State	Value of Residential Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Kentucky	3,074,656	2,244,283	1.370	1.240
Louisiana	2,429,529	1,650,884	1.472	1.332
Maine	821,980	630,393	1.304	1.181
Maryland	6,616,960	4,635,717	1.427	1.292
Massachusetts	7,693,991	5,728,767	1.343	1.216
Michigan	5,383,752	3,501,797	1.537	1.392
Minnesota	5,558,816	3,847,679	1.445	1.308
Mississippi	1,241,083	939,692	1.321	1.196
Missouri	4,754,552	3,588,694	1.325	1.200
Montana	1,148,453	919,206	1.249	1.131
Nebraska	577,746	424,822	1.360	1.231
Nevada	6,697,489	4,026,111	1.664	1.506
New Hampshire	292,227	228,854	1.277	1.156
New Jersey	8,492,015	5,649,618	1.503	1.361
New Mexico	2,236,262	1,395,073	1.603	1.451
New York	16,958,113	12,176,837	1.393	1.261
North Carolina	16,254,736	11,579,895	1.404	1.271
North Dakota	D	D	1.331	1.205
Ohio	6,788,825	4,883,462	1.390	1.259
Oklahoma	1,419,859	1,075,586	1.320	1.195
Oregon	5,519,819	4,019,693	1.373	1.243
Pennsylvania	9,971,624	7,323,399	1.362	1.233
Rhode Island	309,403	205,383	1.506	1.364
South Carolina	5,921,453	4,350,205	1.361	1.232
South Dakota	297,424	228,839	1.300	1.177
Tennessee	5,243,037	3,874,974	1.353	1.225
Texas	32,123,700	21,429,103	1.499	1.357
Utah	4,201,276	3,095,214	1.357	1.229
Vermont	527,837	387,905	1.361	1.232
Virginia	12,761,751	8,799,880	1.450	1.313
Washington	11,158,559	7,361,497	1.516	1.372
West Virginia	348,291	225,500	1.545	1.398
Wisconsin	3,820,533	2,850,921	1.340	1.213
Wyoming	524,809	418,215	1.255	1.136

Source: U.S. Census Bureau. 2007. Residential Building Construction. Sector 236110, Industry Series, Preliminary Detailed Statistics for Establishments: 2007.
Notes: The Census Bureau withheld data for some states, as indicated by the entry "D".

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	8.55	Kentucky	6.00	North Dakota	5.95
Alaska	1.35	Louisiana	8.75	Ohio	7.05
Arizona	7.15	Maine	5.00	Oklahoma	8.40
Arkansas	8.90	Maryland	6.00	Oregon	--
California	8.45	Massachusetts	6.25	Pennsylvania	6.40
Colorado	6.10	Michigan	6.00	Rhode Island	7.00
Connecticut	6.35	Minnesota	7.20	South Carolina	7.20
Delaware	--	Mississippi	7.00	South Dakota	5.40
Dist. of Columbia	6.00	Missouri	7.45	Tennessee	9.45
Florida	6.65	Montana	--	Texas	7.95
Georgia	7.10	Nebraska	6.00	Utah	6.70
Hawaii	4.40	Nevada	7.85	Vermont	6.05
Idaho	6.05	New Hampshire	--	Virginia	5.60
Illinois	8.05	New Jersey	6.95	Washington	8.90
Indiana	7.10	New Mexico	6.60	West Virginia	6.05
Iowa	6.85	New York	8.40	Wisconsin	5.45
Kansas	7.90	North Carolina	6.90	Wyoming	5.50

Source: The Sales Tax Clearinghouse at https://thestc.com/STRates.stm (Accessed on September 11, 2013).

CHAPTER 7. ENERGY USE ANALYSIS

TABLE OF CONTENTS

7.1 INTRODUCTION 7-1
7.2 BUILDING SAMPLES 7-2
7.3 COMMERCIAL WARM-AIR FURNACE ENERGY CONSUMPTION 7-4
7.3.1 Space Heating Fuel Consumption 7-4
7.3.1.1 Determination of Space Heating Burner Operating Hours 7-5
7.3.2 Electricity Consumption 7-7
7.4 SUMMARY OF ENERGY USE RESULTS 7-8

LIST OF TABLES

Table 7.2.1 Selection of CBECS 2003 Records for Furnaces (Replacements) 7-3
Table 7.2.2 Selection of CBECS 2003 Records for Furnaces (New Construction) 7-3
Table 7.2.3 Selection of RECS 2009 Records for Furnaces (Replacements) 7-3
Table 7.2.4 Selection of RECS 2009 Records for Furnaces (New Construction) 7-4
Table 7.3.1 Range of Original Heating Energy Use Based on CBECS 2003 and RECS 2009 Data for Each Furnace Equipment Class, MMBtu/year 7-6
Table 7.3.2 Range of Adjusted Heating Loads for Each Commercial Warm Air Furnace Equipment Class, MMBtu/year 7-7
Table 7.3.3 Range of Baseline Heating Annual Operating Hours for Each Commercial Warm Air Furnace Equipment Class, hours 7-7
Table 7.4.1 Average Annual Energy Consumption and Savings for Commercial Warm Air Furnaces 7-9
Note: A negative value indicates an increase in energy use. 7-9

CHAPTER 7. ENERGY USE ANALYSIS

7.1 INTRODUCTION

The energy use analysis determines the annual energy consumption of commercial warm air furnaces (CWAF) used in the United States and assesses the energy savings potential of increases in thermal efficiency (TE). 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 the equipment in the field. DOE estimated the annual energy consumption of CWAF at specified energy efficiency levels across a range of climate zones, building characteristics, and heating applications.

For the calculation of the energy consumed by CWAF, DOE considered the energy use associated with providing space heating in either commercial or residential buildings. The energy use analysis provides estimates of the distribution of annual energy consumption for CWAF at the efficiency standard levels considered.

DOE developed energy consumption estimates for both gas-fired CWAF and oil-fired CWAF. The CWAF analyzed utilize gas or oil fuel for heating air and the associated electric energy to power a blower, a draft inducer, an ignitor, and other auxiliary equipment.

DOE estimated the energy consumption of CWAF in commercial buildings and housing units by developing a building sample for each of the two equipment classes based on the Energy Information Administration's (EIA) 2003 Commercial Building Energy Consumption Survey (CBECS 2003) and on EIA's 2009 Residential Energy Consumption Survey (RECS 2009).[1,2] These are the latest available surveys for commercial and residential buildings.[a] This sample is further described in section 7.2.

DOE used the CBECS 2003 or RECS 2009 reported heating energy consumption (based on the existing heating system) to calculate the space heating load of each building or household. The heating load represents the amount of heating required to keep a building comfortable throughout an average year.

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 CWAF, and data with respect to the age of the existing CWAF. In addition, DOE made adjustments based on historical weather data, projections of shell efficiency and building square footage, and for buildings that had secondary heating equipment that used the same fuel as the CWAF. To complete the analysis, DOE calculated the energy consumption of alternative (more energy-efficient) equipment, if they replaced existing systems in each commercial building or housing unit.

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[a] At the time of the analysis, only data on building characteristics was available from CBECS 2012. Additionally, EIA is currently working on the 2015 version of RECS, which is not expected to be available until 2017.

7.2 BUILDING SAMPLES

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

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

- used a furnace 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 CWAF subset into further subsets designed to include buildings that use one of the CWAF equipment classes. (See Table 7.2.1 and Table 7.2.2 for commercial applications and Table 7.2.3 and Table 7.2.4 for residential applications.) The new construction sample includes only buildings built after 1990, which DOE believes would have more similar building characteristics to new construction buildings in 2019 (*e.g.,* building size, building insulation, and regional distribution of the buildings).

The CBECS 2003 and RECS 2009 weighting indicates how commonly each commercial building or household configuration occurs in the general population in 2003 and 2009, respectively. DOE adjusted EIA's weightings for each CBECS 2003 building and RECS 2009 household to create CWAF population weights in 2019. The CWAF population weights are adjusted to account for buildings with multiple CWAF and projected growth in the number of CWAF by 2019. Appendix 7A presents the variables included and their definitions, as well as further information about the derivation of the household and building samples, the adjustments to the furnace population weights, and sampling fractions for each of the four samples (commercial (new construction and replacement) and residential (new construction and replacement)).

To sample between the commercial and residential samples, DOE used the shipments model described in chapter 9 to estimate that 2 percent of CWAF shipments would be installed in residential buildings. To sample between the new construction and replacement markets, DOE estimated that the new construction market accounts for 20 percent of gas-fired CWAF and 5 percent of oil-fired CWAF.

Table 7.2.1 Selection of CBECS 2003 Records for Furnaces (Replacements)

Equipment Class	Algorithm	No. of Records	CBECS 2003 Number of Buildings *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square Footage ≥ 3,750 sq ft	1447	1.02	172.4
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square Footage ≥ 3,750 sq ft	111	0.09	2.29

Table 7.2.2 Selection of CBECS 2003 Records for Furnaces (New Construction)

Equipment Class	Algorithm	No. of Records	CBECS 2003 Number of Buildings *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square Footage ≥ 3,750 sq ft Year Constructed ≥ 1990	420	0.27	43.1
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square Footage ≥ 3,750 sq ft Year Constructed ≥ 1990	12	0.01	0.12

Table 7.2.3 Selection of RECS 2009 Records for Furnaces (Replacements)

Equipment Class	Algorithm	No. of Records	RECS 2009 Number of Houses *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square Footage ≥ 11,250 sq ft	45	0.52	3.5
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square Footage ≥ 11,250 sq ft	11	0.08	0.05

Table 7.2.4 Selection of RECS 2009 Records for Furnaces (New Construction)

Equipment Class	Algorithm	No. of Records	RECS 2009 Number of Houses *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square Footage ≥ 11,250 sq ft Year Constructed ≥ 1990	4	0.06	0.9
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square Footage ≥ 11,250 sq ft Year Constructed ≥ 1990	2	0.02	0.002

7.3 COMMERCIAL WARM-AIR FURNACE ENERGY CONSUMPTION

To calculate the energy use of CWAF in each equipment class, DOE determined the energy consumption associated with space heating and any auxiliary electrical use during the periods of heating. DOE estimated the input capacity and burner operational hours of the existing CWAF using building heating loads and furnace characteristics.

The electrical consumption was determined using the burner operating hours associated with space 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 and electrical energy consumption represents the estimated annual energy use of a sampled furnace. Additional details used for determining the total energy use can be found in the following sections.

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

$$Energy\ Use_{TOTAL} = FuelUse_{SH} + ElecUse$$

Eq. 7.1

Where:

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

7.3.1 Space Heating Fuel Consumption

The Department calculated the annual fuel consumption ($FuelUse_{SH}$) for each CWAF using the following formula.

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

Eq. 7.2

Where:

BOH_{SH} = space heating burner operating hours (hr/yr), and
Q_{IN} = input capacity of existing CWAF (kBtu/hr), assumed to be 250 kBtu/h for this analysis.

7.3.1.1 Determination of Space Heating Burner Operating Hours

DOE calculated space heating burner operating hours (BOH_{SH}) for CWAF as:

$$BOH_{SH} = \frac{BHL}{Q_{Useful}}$$

Eq. 7.3

Where:

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

The total useful energy output (Q_{Useful}) includes the output heating capacity of the furnace, as well as useful heat from auxiliary electrical components (such as the electronic ignition, blower, and power to the burner) during the periods of space heating. See appendix 7B for more details.

The annual building-heating load (BHL) is the total amount of heat output from the furnace that the house or building needs during the heating season.[b] This includes heat from the burner and heat from the other electrical components. DOE determined BHL for each sampled housing unit or building, based on the efficiency of the assigned existing CWAF, using the following calculations:

$$BHL = \frac{Q_{YR} \times TE_{ex} \times Adj_{Factor(s)}}{CWAFCount}$$

Eq. 7.4

Where:

Q_{YR} = annual fuel consumption for heating based on CBECS 2003 and RECS 2009 (kBtu/yr),
TE_{ex} = thermal efficiency of the existing CWAF (see appendix 7B),
$Adj_{Factor(s)}$ = adjustment factors (discussed below), and
$CWAFCount$ = number of CWAF used to fulfill the building heating load.

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

[b] BHL is the load served by a single CWAF. DOE assumed that some of the building structures would be served by multiple CWAF based on CBECS or RECS data (one CWAF per 7,500 square feet of heated area).

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

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0.0	3768.1	208.4	15.3	65.6	143.2	251.9	625.2
Oil-fired CWAF	0.0	3464.7	154.0	0.8	15.7	67.1	164.9	457.7

The TE of the existing CWAF (TE_{ex}) is determined by matching historical TE to the data on the distribution of CWAF age for CBECS 2003 buildings or the reported age of the furnace in RECS 2009.[c] See appendix 7B for more details.

DOE adjusted *BHL* to reflect the expectation that buildings in 2019 will have a somewhat different *BHL* than the buildings in the CBECS 2003 and RECS 2009 CWAF sample. The adjustment involves multiplying the calculated *BHL* for each CBECS 2003 or RECS 2009 unit by a building shell efficiency index[d] derived from the National Energy Modeling System (NEMS) simulation performed for EIA's *Annual Energy Outlook* (*AEO 2015)*.[3] For the year 2019, the factors applied in the analysis for replacements in commercial buildings range from 0.75 to 0.96 (depending on the census division of the building and building activity type). For commercial new construction, the factor ranges from 0.35 to 0.86 for space heating. For residential buildings, the factor is 0.85 for replacements and 0.86 for new constructions. This means that buildings on average will have lower space heating loads compared to commercial buildings in 2003 or residential buildings in 2009.

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

$$Adj_{Factor,avg\ climate} = \frac{HDD_{10yr\ avg}}{HDD_{bldg,2009\ or\ 2003}}$$

Eq. 7.5

Where:

$HDD_{bldg,\ 2009\ or\ 2003}$ = HDD in 2003 for CBECS 2003 or 2009 for RECS 2009, for the specific region where the building is located, and,

$HDD_{10yr\ avg}$ = 10-year average HDD (2004–2013) based on NOAA data for the specific region where the unit is located.

[c] CBECS 2003 does not report the age of the equipment, so DOE created a uniform distribution to estimate the age of the equipment.

[d] 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 7.3.2 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).

DOE also accounted for future climate trends based on *AEO 2015* HDD projections by Census division, which show a decline in HDD, leading to lower projected *BHL* in 2019 relative to the non-climate-trend-adjusted *BHL* values.

DOE determined that some of the sampled buildings used multiple heating equipment with the same fuel as the CWAF(s) (*e.g.*, a unit heater or boiler). Therefore, DOE made adjustments when necessary to the calculated *BHL* to reflect the use of secondary heating equipment using the same fuel as the CWAF(s). The adjustment factors are calculated using reported survey information from both CBECS 2003 and RECS 2009 regarding the fraction of heating that was met by different heating equipment.

Table 7.3.2 shows the results for the range in adjusted heating loads among sample buildings and households.

Table 7.3.2 Range of Adjusted Heating Loads for Each Commercial Warm Air Furnace Equipment Class, MMBtu/year

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0.0	2429.6	130.9	9.2	40.2	86.2	159.3	382.1
Oil-fired CWAF	0.0	2474.9	102.7	0.5	9.5	47.7	122.2	308.8

Table 7.3.3 shows the results for the baseline CWAF heating operating hours among sample buildings and households.

Table 7.3.3 Range of Baseline Heating Annual Operating Hours for Each Commercial Warm Air Furnace Equipment Class, hours

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0.0	8760	640.6	44.9	197.2	422.7	780.6	1872.7
Oil-fired CWAF	0.1	8760	473.5	2.3	46.0	230.5	590.4	1492.1

7.3.2 Electricity Consumption

The Department calculated CWAF electricity consumption for the circulating blower, the draft inducer, and the ignitor. The circulating blower moves conditioned air through the building whenever the CWAF burner is on (adjusted for delay times between burner and blower operation).

The blower, in addition to moving heated air through the house, can operate during the cooling season (summer) if the building is air-conditioned. Therefore, the Department also

considered the difference in electricity consumption of higher-efficiency products during the cooling season and ventilation operation ($DiffElecUse_{Fan}$).[e]

In addition, some higher efficiency installations require the use of auxiliary equipment such as condensate pumps and heat tape. DOE calculated the electricity consumption of this equipment and added it to the total electricity consumption of the CWAF. Details of how DOE determined whether a household required heat tape or a condensate pump can be found in appendix 8D.

DOE calculated the electricity consumption as:

$$ElecUse_{TOTAL} = ElecPower_{ElecComp} \times BOH_{SH} + ElecUse_{Aux} + DiffElecUse_{fan} + (8760 - BOH_{SH}) \times StbyE$$

Eq. 7.6

Where:

$ElecPower_{ElecComp}$ = power of multiple electrical components required during furnace operation, (kW) (refer to the test procedure variables that relate to electricity consuming components as detailed in appendix 7B),
BOH_{SH} = as defined in section 7.3.1.1,
$ElecUse_{Aux}$ = electricity use of the auxiliary equipment, such as condensate pumps and heat tape, (kWh),
$DiffElecUse_{Fan}$ = differential of electricity use of the furnace fan during cooling and ventilation for condensing CWAF, (kWh),
8760 = hours in one year, and
StbyE = power consumption during standby (kW).

The details for calculating electricity consumption are presented in appendix 7B.

7.4 SUMMARY OF ENERGY USE RESULTS

This section 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 CWAF equipment class. The results reflect energy use in both the commercial and residential samples. The life-cycle cost and payback period analysis uses the results calculated for each sample building.

[e] Condensing CWAF tend to have a more restricted airflow path (because of the secondary heat exchanger) than non-condensing CWAF. In general, the furnace fan requires more energy to produce the equivalent airflow output for a condensing CWAF compared to a similar non-condensing CWAF. The analysis accounts for this additional energy consumption and resulting additional heat released by the CWAF fan motor that needs to be compensated by the central air conditioner.

Table 7.4.1 Average Annual Energy Consumption and Savings for Commercial Warm Air Furnaces

EL	Design Option	Annual Fuel Use		Annual Electricity Consumption of Auxiliary Components	
		Total *MMBtu/yr*	Savings *MMBtu/yr*	Total *kWh/yr*	Savings *kWh/yr*
Commercial Gas-Fired Commercial Warm Air Furnace					
0	80% TE - Baseline	160.2	-	836.8	-
1	81% TE – Increased HX Area	158.2	1.9	827.7	9.0
2	82% TE – Increased HX Area	156.3	3.8	818.9	17.8
3	92% TE – Condensing (Max Tech)	139.6	20.5	1044.5	-207.8
Commercial Oil-fired CWAF					
0	81% TE - Baseline	118.4	-	698.4	-
1	82% TE – Increased HX Area	117.2	1.2	692.3	6.0
2	92% TE – Condensing (Max Tech)	106.8	11.6	931.5	-239.1

Note: A negative value indicates an increase in energy use.

REFERENCES

1. U.S. Department of Energy–Energy Information Administration. *2003 CBECS Survey Data*. (Last accessed June 9, 2015.) http://www.eia.gov/consumption/commercial/data/2003/index.cfm?view=microdata.

2. U.S. Department of Energy–Energy Information Administration. *2009 RECS Survey Data*. (Last accessed June 9, 2015.) http://www.eia.gov/consumption/residential/data/2009/.

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 June 5, 2015.) http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

4. National Oceanic and Atmospheric Administration. *Climate Data Online*. (Last accessed June 30, 2015.) http://www.ncdc.noaa.gov/cdo-web/.

APPENDIX 7A. BUILDING VARIABLES

TABLE OF CONTENTS

7A.1 INTRODUCTION 7A-1
7A.2 CBECS 2003 SAMPLE DETERMINATION 7A-1
7A.3 CBECS 2003 DATABASE VARIABLE RESPONSE CODES 7A-3
7A.4 RECS 2009 SAMPLE DETERMINATION 7A-5
7A.5 RECS 2009 DATABASE VARIABLE RESPONSE CODES 7A-8

LIST OF TABLES

Table 7A.2.1 Selection of CBECS 2003 Records for Commercial Warm Air Furnaces (Replacements) 7A-2
Table 7A.2.2 Selection of CBECS 2003 Records for Commercial Warm Air Furnaces (New Construction) 7A-2
Table 7A.2.3 CBECS 2003 Variables Used for Commercial Warm Air Furnaces 7A-3
Table 7A.3.1 CBECS 2003 Variable Response Codes 7A-3
Table 7A.4.1 Selection of RECS 2009 Records for Commercial Warm Air Furnaces (Replacements) 7A-6
Table 7A.4.2 Selection of RECS 2009 Records for Commercial Warm Air Furnaces (New Construction) 7A-6
Table 7A.4.3 List of RECS 2009 Variables Used for Commercial Warm Air Furnaces 7A-7
Table 7A.5.1 Definitions of RECS 2009 Variables Used in Life-Cycle Cost Analysis 7A-8

APPENDIX 7A. BUILDING VARIABLES

7A.1 INTRODUCTION

Using Microsoft ACCESS, DOE created a database containing a subset of the records and variables from DOE's Energy Information Administration (EIA)'s 2003 Commercial Building Energy Consumption Survey (CBECS 2003), as well as RECS 2009.[1,2] DOE used this CBECS 2003 and RECS 2009 subset in the life-cycle cost (LCC) analysis of the commercial warm air furnace (CWAF) rulemaking. This appendix explains the variable name abbreviations and provides definitions of the variable values.

7A.2 CBECS 2003 SAMPLE DETERMINATION

The subset of CBECS 2003 records used for CWAF met all of the following criteria:

1) a packaged heating units or furnaces that heat air directly served as a source of gas or oil heating,
2) building is not vacant,
3) a warm air furnace is used as the heating equipment at least a portion of the building,[a] and,
4) heated square footage is equal to or greater than 3,750.

Buildings were assigned to the sub-samples based on the amount of heating area per CWAF. CBECS 2003 provides the total heating square footage and the fraction of heating by the CWAF for each building record, but does not provide the number of commercial warm air furnaces used by the building, so DOE assumed that each CWAF would satisfy 7,500 square feet.

The CBECS 2003 weighting indicates how commonly each building configuration occurs in the general population. Table 7A.4.1 shows the CBECS 2003 sample weights and criteria for replacements and Table 7A.4.2 shows the CBECS 2003 sample weights and criteria for new construction. For the entire CBECS 2003 dataset, refer to www.eia.gov/consumption/commercial/data/2003/index.cfm?view=microdata.

[a] Sum of the fraction of all other heating equipment is less than 100 percent.

Table 7A.2.1 Selection of CBECS 2003 Records for Commercial Warm Air Furnaces (Replacements)

Equipment Class	Algorithm	No. of Records	CBECS 2003 Number of Buildings *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square Footage ≥ 3,750 sq ft	1447	1.02	172.4
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square Footage ≥ 3,750 sq ft	111	0.09	2.29

Table 7A.2.2 Selection of CBECS 2003 Records for Commercial Warm Air Furnaces (New Construction)

Equipment Class	Algorithm	No. of Records	CBECS 2003 Number of Buildings *million*	DOE Estimated CWAF Shipments in 2019 *million*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square footage ≥ 3,750 sq ft Year Constructed ≥ 1990	420	0.27	43.1
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square footage ≥3,750 sq ft Year Constructed ≥ 1990	12	0.01	0.12

Table 7A.2.3 CBECS 2003 Variables Used for Commercial Warm Air Furnaces

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
NGHT18	Natural gas used for main heating
NGHT28	Natural gas used for secondary heating
FKHT18	Fuel oil used for main heating
FKHT28	Fuel oil used for secondary heating
NWMNHT8	Main heating replaced since 1990
NGHTBTU8	Natural Gas heating use (mBtu)
FKHTBTU8	Fuel Oil heating use (mBtu)
ELCLBTU8	Electric cooling use (mBtu)
ELVNBTU8	Electric ventilation use (mBtu)

7A.3 CBECS 2003 DATABASE VARIABLE RESPONSE CODES

Table 7A.3.1 provides the response codes for all CBECS 2003 variables used in the CWAF sample.

Table 7A.3.1 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
	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
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
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
NGHTBTU8	Thousand BTU	
FKHTBTU8	Thousand BTU	
ELCLBTU8	Thousand BTU	
ELVNBTU8	Thousand BTU	

7A.4 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 CWAF met all of the following criteria:

- used a shared central furnace as the main or secondary source of heat,
- used a heating fuel that is natural gas, LPG, or fuel oil,
- had an energy consumption greater than zero, and
- heated square footage is equal to or greater than 11,250.

Buildings were assigned to the sub-samples based on the amount of heating area per CWAF. RECS 2009 provides the total heating square footage for each building record, but does not provide the number of CWAF used by the building, so DOE assumed that each CWAF would satisfy 7,500 square feet.

The RECS 2009 weighting indicates how commonly each household configuration occurs in the general population. Table 7A.4.1 shows the RECS sample weights and criteria for replacements and Table 7A.4.2 shows the RECS sample weights and criteria for new construction. For the entire RECS 2009 dataset, refer to www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata

Table 7A.4.1 Selection of RECS 2009 Records for Commercial Warm Air Furnaces (Replacements)

Equipment Class	Algorithm	No. of Records	RECS 2009 Number of Houses *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace[b] Heated Square Footage ≥ 11,250 sq ft	45	0.52	3.5
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square footage ≥ 11,250 sq ft	11	0.08	0.05

Table 7A.4.2 Selection of RECS 2009 Records for Commercial Warm Air Furnaces (New Construction)

Equipment Class	Algorithm	No. of Records	RECS 2009 Number of Houses *million*	DOE Estimated CWAF Shipments in 2019 *thousand*
Gas-Fired Commercial Warm Air Furnace	Heating Equipment = Gas Furnace Heated Square Footage ≥ 11,250 sq ft Year Constructed ≥ 1990	4	0.06	0.9
Oil-Fired Commercial Warm Air Furnace	Heating Equipment = Oil Furnace Heated Square Footage ≥ 11,250 sq ft Year Constructed ≥ 1990	2	0.02	0.002

Table 7A.4.3 lists the variables use in the analysis.

[b] Natural Gas or LPG furnace.

Table 7A.4.3 List of RECS 2009 Variables Used for Commercial Warm Air Furnaces

Variable	Description
Location Variables	
REGIONC	Census Region
DIVISION	Census Division
REPORTABLE_DOMAIN	Reportable states and groups of states
UR	Housing unit classified as urban or rural by Census
HDD65	Heating degree days in 2009, base temperature 65F
HDD30YR	Heating degree days, 30-year average 1981-2010, base 65F
CDD65	Heating degree days in 2009, base temperature 65F
CDD30YR	Cooling degree days, 30-year average 1981-2010, base 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
BTUELCOL	Electricity usage for air-conditioning, central and window/wall (room), 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
WARMAIR	Central warm-air furnace used for secondary space heating
FURNFUEL	Fuel used by warm-air furnace for secondary space heating
REVERSE	Heat pump used for secondary space heating
RADFUEL	Fuel used by hot water system for secondary space heating
PIPEFUEL	Fuel used by pipeless furnace for secondary space heating
RMHTFUEL	Fuel used by built-in electric units for secondary space heating
HSFUEL	Fuel used by heating stove for secondary space heating
PERMELEC	Built-in electric units used for secondary space heating
CARRYEL	Portable electric heaters used for secondary space heating
FPFUEL	Fuel used by fireplace for secondary space heating
RNGFUEL	Fuel used by cooking stove for secondary space heating
DIFFUEL	Fuel used by other secondary space heating equipment
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
USECENAC	Frequency central air conditioner used in summer 2009

Variable	Description
AGECENAC	Age of central air conditioner
ACOTHERS	Central air conditioner cools other homes, business, or farm
NUMBERAC	Number of window/wall air conditioning units used
USEWWAC	Frequency most-used window/wall air conditioning unit used in summer 2009
MAINTAC	Routine service or maintenance performed on central air conditioner
StationID*	ID number of weather station identified with household (see appendix 7D)
CELLAR	Basement in housing unit
BASEFIN	Finished basement
BASEHEAT	Heating used in basement
BASECOOL	Cooling used in basement
PRKGPLC1	Attached garage
CRAWL	Housing unit over a crawl space
ATTIC	Attic in housing unit
ATTICFIN	Finished attic
ATTCHEAT	Heating used in attic
ATTCCOOL	Cooling used in attic
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
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.5 RECS 2009 DATABASE VARIABLE RESPONSE CODES

Table 7A.5.1 provides the response codes for all RECS 2009 variables used in the CWAF sample.

Table 7A.5.1 Definitions of RECS 2009 Variables Used in Life-Cycle Cost Analysis

Variable	Response Codes
ACOTHERS	0 No 1 Yes -2 Not Applicable
AGECENAC	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
ATTCCOOL	0 No 1 Yes -2 Not Applicable
ATTCHEAT	0 No 1 Yes -2 Not Applicable
ATTIC	0 No 1 Yes -2 Not Applicable
ATTICFIN	0 No 1 Yes -2 Not Applicable
BASECOOL	0 No 1 Yes -2 Not Applicable
BASEFIN	0 No 1 Yes -2 Not Applicable
BASEHEAT	0 No 1 Yes -2 Not Applicable
BTUELCOL	Thousand BTU
BTUELSPH	Thousand BTU
BTUFOSPH	Thousand BTU
BTULPSPH	Thousand BTU
BTUNGSPH	Thousand BTU
CARRYEL	0 No 1 Yes -2 Not Applicable
CATHCEIL	0 No 1 Yes -2 Not Applicable
CDD30YR	Cooling degree days, 30-year average 1981-2010, base 65F
CDD65	Cooling degree days in 2009, base temperature 65F
CELLAR	0 No 1 Yes -2 Not Applicable
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
CRAWL	0 1 -2	No Yes Not Applicable
DIFFUEL	1 2 3 4 5 7 8 9 21 -2	Natural Gas Propane/LPG Fuel Oil Kerosene Electricity Wood Solar District Steam Other Fuel Not Applicable
DIVISION	1 2 3 4 5 6 7 8 9 10	New England Census Division (CT, MA, ME, NH, RI, VT) Middle Atlantic Census Division (NJ, NY, PA) East North Central Census Division (IL, IN, MI, OH, WI) West North Central Census Division (IA, KS, MN, MO, ND, NE, SD) South Atlantic Census Division (DC, DE, FL, GA, MD, NC, SC, VA, WV) East South Central Census Division (AL, KY, MS, TN) West South Central Census Division (AR, LA, OK, TX) 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
EQMAMT	1 2 3 -2	Almost all About three-fourths Closer to half Not Applicable
EQUIPAGE	1 2 3 41 42 5 -2	Less than 2 years old 2 to 4 years old 5 to 9 years old 10 to 14 years old 15 to 19 years old 20 years or older Not Applicable
EQUIPM	2 3 4 5 6 7 8 9 10 11	Steam or Hot Water System Central Warm-Air Furnace Heat Pump Built-In Electric Units Floor or Wall Pipeless Furnace Built-In Room Heater Heating Stove Fireplace Portable Electric Heaters Portable Kerosene Heaters

	12	Cooking Stove
	21	Other Equipment
	-2	Not Applicable
	1	Natural Gas
	2	Propane/LPG
	7	Wood
	21	Other Fuel
FPFUEL	-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
	9	District Steam
	21	Other Fuel
FURNFUEL	-2	Not Applicable
HDD30YR	Heating degree days, 30-year average 1981-2010, base 65F	
HDD65	Heating degree days in 2009, base temperature 65F	
	0	No
	1	Yes
HEATOTH	-2	Not Applicable
	0	No
	1	Yes
HIGHCEIL	-2	Not Applicable
	7	Wood
	21	Other Fuel
HSFUEL	-2	Not Applicable
	0	No
	1	Yes
MAINTAC	-2	Not Applicable
	0	No
	1	Yes
MAINTHT	-2	Not Applicable
	1 - 9	Number of floors in apartment
NAPTFLRS	-2	Not Applicable
NHSLDMEM	0 - 15	Number of household members
NUMAPTS	5 - 995	Number of apartment units

	-2	Not Applicable
NUMBERAC	1 - 15	Number of window/wall air conditioning units used
	-2	Not Applicable
NWEIGHT	Final sample weight	
PERMELEC	0	No
	1	Yes
	-2	Not Applicable
PIPEFUEL	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
PRKGPLC1	0	No
	1	Yes
	-2	Not Applicable
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
REGIONC	1	Northeast Census Region
	2	Midwest Census Region
	3	South Census Region
	4	West Census Region
REPORTABLE_DOMAIN	1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont
	2	Massachusetts
	3	New York
	4	New Jersey
	5	Pennsylvania
	6	Illinois
	7	Indiana, Ohio
	8	Michigan
	9	Wisconsin
	10	Iowa, Minnesota, North Dakota, South Dakota
	11	Kansas, Nebraska
	12	Missouri
	13	Virginia
	14	Delaware, District of Columbia, Maryland, West 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 27 Alaska, Hawaii, Oregon, Washington
REVERSE	0 No 1 Yes -2 Not Applicable
RMHTFUEL	1 Natural Gas 2 Propane/LPG 3 Fuel Oil 4 Kerosene -2 Not Applicable
RNGFUEL	1 Natural Gas 2 Propane/LPG 3 Fuel Oil 4 Kerosene 5 Electricity 7 Wood 21 Other Fuel -2 Not Applicable
StationID	Three character identifier for weather station
STORIES	10 One story 20 Two stories 31 Three stories 32 Four or more stories 40 Split-level 50 Other type -2 Not Applicable
TOTCSQFT	Square Feet
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
UR	U Urban R Rural
USECENAC	1 Turned on only a few days or nights when really needed 2 Turned on quite a bit

	3	Turned on just about all summer
	-2	Not Applicable
USEWWAC	1	Turned on only a few days or nights when really needed
	2	Turned on quite a bit
	3	Turned on just about all summer
	-2	Not Applicable
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
WARMAIR	0	No
	1	Yes
	-2	Not Applicable
YEARMADE	1600 - 2009	Year housing unit was built

* Not part of RECS 2009 variables.

REFERENCES

1. U.S. Department of Energy–Energy Information Administration. *2003 CBECS Survey Data*. (Last accessed June 9, 2015.) http://www.eia.gov/consumption/commercial/data/2003/index.cfm?view=microdata.

2. U.S. Department of Energy–Energy Information Administration. *2009 RECS Survey Data*. (Last accessed June 9, 2015.) http://www.eia.gov/consumption/residential/data/2009/.

APPENDIX 7B. DETERMINATION OF COMMERCIAL WARM AIR FURNACE ENERGY USE IN THE LCC ANALYSIS

TABLE OF CONTENTS

7B.1 INTRODUCTION 7B-1
7B.2 DETERMINATION OF ANNUAL FUEL ENERGY CONSUMPTION 7B-1
7B.2.1 Determination of Burner Operating Hours (BOH_{SH}) 7B-1
7B.2.2 Determination of Building Heating Load Estimates for Furnace 7B-2
7B.2.2.2 Adjustment Factors for the Building Heating Load 7B-4
7B.2.3 Assigning Commercial Warm Air Furnace Equipment Characteristics to Sampled Buildings 7B-11
7B.2.3.1 Derivation of Existing TE 7B-11
7B.3 DETERMINATION OF ANNUAL ELECTRICAL ENERGY CONSUMPTION 7B-12
7B.3.1 Furnace Electricity Consumption (Heating Season) 7B-13
7B.3.2 Electricity Consumption Auxiliary Equipment 7B-14
7B.3.3 Non-Heating Furnace Fan Energy Use Differential 7B-14

LIST OF TABLES

Table 7B.2.1 Range of Reported Heating Energy Use for Each Commercial Furnace Equipment Class in CBECS 2003 and RECS 2009, MMBtu/year 7B-3
Table 7B.2.2 Range of Adjusted Heating Load for Each Equipment Class by Region, MMBtu/year 7B-3
Table 7B.2.3 Range of Baseline Heating Annual Burner Operating Hours for Each Equipment Class, hours 7B-4
Table 7B.2.4 2019 Commercial Building Shell Index for Space Heating, Replacements (based on AEO 2015 Reference Case) 7B-5
Table 7B.2.5 Commercial Building Shell Index for Space Heating, New Construction (based on AEO 2015 Reference Case) 7B-5
Table 7B.2.6 Mapping of Commercial NEMS Index IDs to CBECS 2003 PBA ID 7B-6
Table 7B.2.7 Residential Building Shell Index for Space Heating (based on AEO 2015 Reference Case) 7B-7
Table 7B.2.8 HDD Adjustment Factors by CBECS 2003 Regions (based on NOAA data) 7B-8
Table 7B.2.9 HDD Adjustment Factors by RECS 2009 Census Divisions (based on NOAA data) 7B-9
Table 7B.2.10 Projected HDD by Census Divisions from AEO 2015 ..... 7B-10
Table 7B.2.11 Climate Change HDD Adjustment Factors by Census Division* 7B-11
Table 7B.2.12 Shipment-Weighted TE for Gas-Fired and Oil-Fired Commercial Warm Air Furnaces 7B-12

Table 7B.3.1 Range of Original Cooling Energy Use Based on CBECS 2003 and RECS 2009 Data for Each CWAF Equipment Class, MMBtu/year....7B-16
Table 7B.3.2 Range of Adjusted Cooling Loads for Each Equipment Class, MMBtu/year....7B-17
Table 7B.3.3 Range of Baseline Cooling Annual Operating Hours for Each Equipment Class, hours 7B-17
Table 7B.3.4 Range of Additional Electricity Use for Condensing Furnace Designs in Cooling and Ventilation Mode, kWh/yr 7B-18

APPENDIX 7B. DETERMINATION OF COMMERCIAL WARM AIR FURNACE ENERGY USE IN THE LCC ANALYSIS

7B.1 INTRODUCTION

For the calculation of the energy consumed by commercial warm air furnaces (CWAF), DOE considered the energy use associated with providing space heating, as well as the impact of installing higher-efficiency CWAF on the electricity use of the furnace fan during the cooling season to accurately reflect field operation. The calculation used for the determination of the total energy use is as follows:

$$Total\ Energy\ Use = FuelUse_{SH} + ElecUse$$

Eq. 7B.1

This appendix provides additional details regarding the energy use calculation methodology.

7B.2 DETERMINATION OF ANNUAL FUEL ENERGY CONSUMPTION

The average annual fuel consumption during space heating ($FuelUse_{SH}$) is calculated using the following formula:

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

Eq. 7B.2

Where:

BOH_{SH} = number of burner operating hours for each building (see section 7B.2.1), and
Q_{IN} = steady-state nameplate input rate in Btu/h, assumed to be 250 kBtu/h for this analysis.

DOE assumed that all CWAF are single-stage units.

7B.2.1 Determination of Burner Operating Hours (BOH_{SH})

DOE calculated space heating burner operating hours (BOH_{SH}) for CWAF as:

$$BOH_{SH} = \frac{BHL}{Q_{Useful}}$$

Eq. 7B.3

Where:

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

The total useful energy output (Q_{Useful}) includes the output heating capacity of the furnace, as well as useful heat from auxiliary electrical components (such as the electronic ignition, blower, and power to the burner) during the periods of space heating. The formula is as follows:

$$Q_{Useful} = Q_{OUT} + y_P PE + yBE + y_{IG} PE_{IG}$$

Eq. 7B.4

Where:

Q_{OUT} = maximum fuel output rate heating capacity (see Eq. 7B.5),
y_P = ratio of induced or forced draft blower on-time to average burner on-time (see section 7B.3.1),
PE = burner electrical power at full-load steady-state operation in kW (see section 7B.3.1),
y = blower on-time to burner on-time (see section 7B.3),
BE = circulating air fan electrical power at full-load steady-state operation in kW (see section 7B.3.1),
y_{IG} = ratio of burner interrupted-ignition device on-time to average burner on-time (see section 7B.3), and
PE_{IG} = electrical input rate to the interrupted ignition device on the burner in kW (see section 7B.3.1).

Q_{OUT} for all equipment classes is calculated using the following equation:

$$Q_{OUT} = Q_{IN} \times TE$$

Eq. 7B.5

Where:

Q_{IN} = as defined in Eq. 7B.2, and
TE = thermal efficiency of the CWAF.

7B.2.2 Determination of Building Heating Load Estimates for Furnace

The annual building heating load (*BHL*) is the total amount of heat output from the furnace that the building or house needs during the heating season.[a] DOE determined projected *BHL* in 2019 for each sampled building or housing unit, based on the efficiency of the assigned existing furnace, using the following calculation:

$$BHL = \frac{Q_{YR} \times TE_{ex} \times Adj_{Factor(s)}}{CWAFCount}$$

Eq. 7B.6

Where:

[a] *BHL* is the load served by a single CWAF. DOE assumed that some buildings and houses would be served by multiple CWAF based on CBECS data. DOE also assumed that some CWAF serve multiple houses or buildings.

Q_{YR} = annual fuel consumption for heating based on CBECS 2003 or RECS 2009 (kBtu/yr),
TE_{ex} = TE of the existing furnace (see section 7B.2.3.1),
Adj_{Factor} = adjustment factor (see section 7B.2.2.1), and
CWAFCount = number of CWAF used to fulfill the building heating load.

Both CBECS 2003 and RECS 2009 report fuel consumption for heating (Q_{YR}) for each of the sampled buildings. Table 7B.2.1 shows the original CBECS 2003 and RECS 2009 heating energy use for the sampled buildings.

Table 7B.2.1 Range of Reported Heating Energy Use for Each Commercial Furnace Equipment Class in CBECS 2003 and RECS 2009, MMBtu/year

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0.0	3768.1	208.4	15.3	65.6	143.2	251.9	625.2
Oil-fired CWAF	0.0	3464.7	154.0	0.8	15.7	67.1	164.9	457.7

The TE of the existing CWAF (TE_{ex}) is determined by matching historical TE data to the data on the distribution of CWAF age for CBECS 2003 buildings or the reported age of the CWAF in RECS 2009. See section 7B.2.3.1 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.

DOE calculated the national average annual heating load to be 130.9 MMBtu/yr for gas-fired CWAFs and 102.7 MMBtu/yr for oil-fired CWAFs in 2019. The variations between equipment classes primarily reflect differences in the geographical distribution of CWAFs and the differences in building characteristics. These results are smaller than those reported in CBECS 2003 or RECS 2009, primarily due to projected improvements in building shell efficiency and projected lower heating loads due to decreased heating degree days. Table 7B.2.2 shows the range of adjusted heating load among sample households.

Table 7B.2.2 Range of Adjusted Heating Load for Each Equipment Class by Region, MMBtu/year

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0.0	2429.6	130.9	9.2	40.2	86.2	159.2	382.1
Oil-fired CWAF	0.0	2474.9	102.7	0.5	9.5	47.7	122.2	308.8

Once the heating load of each sample building or housing unit is known, it is possible to estimate what the burner operating hours and energy consumption of the baseline equipment (80-percent TE) as well as more-efficient equipment used in the analysis. Table 7B.2.3 shows the

results for the baseline CWAF (80-percent TE) space heating burner operating hours among sample buildings and households in 2019.

Table 7B.2.3 Range of Baseline Heating Annual Burner Operating Hours for Each Equipment Class, hours

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0.0	8760	640.6	44.9	197.2	422.7	780.4	1872.7
Oil-fired CWAF	0.1	8760	473.5	2.3	46.0	230.5	590.4	1492.1

7B.2.2.2 Adjustment Factors for the Building Heating Load

Building Shell Efficiency Index DOE adjusted the BHL to reflect the expectation that the buildings in 2019 will have a somewhat different BHL than the buildings in the CBECS 2003 and RECS 2009 CWAF sample. The first adjustment involves multiplying the calculated BHL for each CBECS 2003 or RECS 2009 building by the building shell efficiency index[b] based on information from the National Energy Modeling System (NEMS) simulation performed for the Energy Information Administration's (EIA) *Annual Energy Outlook* (*AEO 2015)*.[1] For the year 2019, the factor applied to replacements in commercial buildings range from 0.75 to 0.96 in the case of space heating (depending on the Census division of the building) (as shown in Table 7B.2.4). For commercial new constructions, the factor ranges from 0.35 to 0.86 for space heating. (Table 7B.2.5) Table 7B.2.6 shows the mapping of NEMS commercial building types to the commercial building types reported in CBECS 2003. For residential buildings, in the case of space heating the factor is 0.85 for replacements and 0.86 for new construction (Table 7B.2.7). This means that buildings on average will have lower space heating loads compared to commercial buildings in 2003 or residential buildings in 2009.

[b] The building shell efficiency index sets the heating load value at 1.00 for an average building in 2003 or 2009 for CBECS 2003 and RECS 2009, respectively, in each census division. The values listed 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.2.4 2019 Commercial Building Shell Index for Space Heating, Replacements (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	0.95	0.92	0.95	0.93	0.91	0.87	0.87	0.92	0.75
2	Education	0.92	0.90	0.92	0.90	0.90	0.85	0.86	0.91	0.81
3	Food Sales	0.95	0.94	0.96	0.94	0.94	0.93	0.94	0.95	0.94
4	Food Service	0.94	0.94	0.94	0.94	0.94	0.94	0.95	0.94	0.95
5	Health Care	0.93	0.92	0.92	0.91	0.91	0.91	0.91	0.94	0.85
6	Lodging	0.94	0.91	0.93	0.93	0.92	0.91	0.91	0.94	0.92
7	Large Office	0.95	0.94	0.95	0.95	0.91	0.91	0.89	0.94	0.81
8	Small Office	0.93	0.91	0.92	0.90	0.91	0.87	0.90	0.92	0.85
9	Merc Service	0.94	0.92	0.93	0.93	0.93	0.90	0.91	0.94	0.79
10	Warehouse	0.89	0.91	0.88	0.92	0.89	0.91	0.88	0.85	0.83
11	Other	0.92	0.91	0.92	0.90	0.90	0.81	0.82	0.90	0.75

Table 7B.2.5 Commercial Building Shell Index for Space Heating, New Construction (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	0.81	0.72	0.83	0.77	0.74	0.60	0.62	0.79	0.36
2	Education	0.78	0.70	0.78	0.73	0.74	0.61	0.70	0.76	0.52
3	Food Sales	0.84	0.82	0.85	0.83	0.84	0.80	0.83	0.86	0.83
4	Food Service	0.82	0.83	0.82	0.82	0.83	0.83	0.83	0.83	0.84
5	Health Care	0.82	0.78	0.82	0.79	0.80	0.78	0.80	0.86	0.64
6	Lodging	0.81	0.78	0.81	0.82	0.80	0.77	0.80	0.85	0.78
7	Large Office	0.83	0.75	0.84	0.82	0.75	0.69	0.67	0.82	0.35
8	Small Office	0.74	0.67	0.74	0.69	0.74	0.61	0.71	0.78	0.55
9	Merc Service	0.82	0.76	0.79	0.79	0.82	0.73	0.76	0.84	0.53
10	Warehouse	0.68	0.73	0.68	0.72	0.71	0.72	0.67	0.61	0.53
11	Other	0.80	0.77	0.81	0.77	0.77	0.58	0.59	0.75	0.36

Table 7B.2.6 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	Non-refrigerated 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

Table 7B.2.7 Residential Building Shell Index for Space Heating (based on AEO 2015 Reference Case)

Year	Pre-2009 Homes	New Construction
2011	0.90	0.85
2012	0.89	0.85
2013	0.89	0.85
2014	0.88	0.88
2015	0.88	0.86
2016	0.87	0.86
2017	0.87	0.86
2018	0.86	0.86
2019	0.85	0.86
2020	0.85	0.86
2021	0.84	0.85
2022	0.83	0.85
2023	0.83	0.85
2024	0.82	0.85
2025	0.81	0.85
2026	0.81	0.85
2027	0.80	0.85
2028	0.80	0.85
2029	0.79	0.85
2030	0.78	0.85
2031	0.78	0.85
2032	0.77	0.85
2033	0.76	0.85
2034	0.76	0.85
2035	0.75	0.84
2036	0.74	0.84
2037	0.74	0.84
2038	0.73	0.84
2039	0.72	0.84
2040	0.72	0.84

Average Climate Conditions. DOE also adjusted the calculated *BHL* 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:[2]

$$Adj_{Factor,avg\ climate} = \frac{HDD_{10yr\ avg}}{HDD_{bldg,2009\ or\ 2003}}$$

Eq. 7B.7

Where:

$HDD_{bldg,\ 2009\ or\ 2003}$ = HDD in 2003 for CBECS 2003 or 2009 for RECS 2009 for the specific region where the unit is located, and,

$HDD_{10yr\ avg}$ = 10-year average HDD (2004–2013) based on NOAA data for the specific region where the unit is located.

As shown in Table 7B.2.8, the historical average climate conditions adjustment factors for commercial buildings range from 0.82 to 1.20 and have an average of 0.94 for the CWAF building sample (*i.e.*, 2003 was in general colder than the 10-year average). As shown in Table 7B.2.9, this adjustment factor for residential buildings range from 0.96 to 1.07, with an average of 1.04 for the CWAF building sample (*i.e.*, 2009 was in general warmer than the 10-year average).

Table 7B.2.8 HDD Adjustment Factors by CBECS 2003 Regions (based on NOAA data)

ID	Division Name	2003 HDD	10-Year Avg. (2004-2013)	HDD Adjustment Factor
1	New England	6969	6281	0.99
2	Middle Atlantic	6257	5635	0.96
3	East North Central	6531	6168	0.87
4	West North Central	6615	6468	0.88
5	South Atlantic	2800	2621	0.92
6	East South Central	3570	3408	0.87
7	West South Central	2179	2060	0.82
8	Mountain	4805	5062	0.96
9	Pacific	3227	3364	1.20

Table 7B.2.9 HDD Adjustment Factors by RECS 2009 Census Divisions (based on NOAA data)

Region	States	2009 HDD	10-Year Avg. (2004-2013)	HDD Adjustment Factor
1	CT, ME, NH, RI, VT	6854	6488	1.06
2	Massachusetts	6383	6043	1.06
3	New York	6235	5909	1.06
4	New Jersey	5294	5045	1.05
5	Pennsylvania	5880	5623	1.05
6	Illinois	6385	6017	1.06
7	Indiana, Ohio	5879	5624	1.05
8	Michigan	7036	6634	1.06
9	Wisconsin	7890	7429	1.06
10	IA, MN, ND, SD	8403	7897	1.06
11	Kansas, Nebraska	5729	5377	1.07
12	Missouri	5176	4923	1.05
13	Virginia	4431	4216	1.05
14	DE, DC, MD	4291	4076	1.05
15	Georgia	2981	2822	1.06
16	NC, SC	3283	3122	1.05
17	Florida	705	690	1.02
18	AL, KY, MS	3348	3227	1.04
19	Tennessee	3903	3742	1.04
20	AR, LA, OK	2827	2703	1.05
21	Texas	1849	1793	1.03
22	Colorado	7354	7102	1.04
23	ID, MT, UT, WY	7696	7436	1.03
24	Arizona	1894	1982	0.96
25	NV, NM	3989	3975	1.00
26	California	2879	2899	0.99
27	OR, WA	5822	5650	1.03
28	Alaska*	-	-	1.03
29	Hawaii**	-	-	0.99
30	West Virginia	5233	5046	1.04

* No data for region. Set equal to region 27 HDD adjustment factor
** No data for region. Set equal to region 26 HDD adjustment factor.

Climate Change. DOE also accounted for future climate trends based on *AEO 2015* HDD projections by Census division (as shown in Table 7B.2.10), which show a decline in HDD, leading to lower projected *BHL* in 2019 relative to the non-climate-trend-adjusted *BHL* values. DOE used 2014 as the base year of the projected and calculated HDD adjustment factors as shown in for each Census division.

Table 7B.2.10 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.2.11 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
2012	0.82	0.79	0.73	0.74	0.76	0.71	0.65	0.95	1.22	0.81
2013	0.95	0.93	0.91	0.96	0.90	0.90	0.91	1.10	1.21	0.96
2014	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2015	0.93	0.90	0.86	0.88	0.90	0.87	0.86	1.00	1.07	0.91
2016	0.90	0.87	0.83	0.86	0.87	0.83	0.79	1.02	1.25	0.90
2017	0.90	0.87	0.83	0.86	0.86	0.83	0.78	1.02	1.25	0.90
2018	0.89	0.87	0.83	0.86	0.86	0.83	0.78	1.02	1.25	0.89
2019	0.89	0.86	0.82	0.86	0.86	0.83	0.78	1.02	1.25	0.89
2020	0.89	0.86	0.82	0.86	0.86	0.83	0.77	1.01	1.25	0.89
2021	0.88	0.86	0.82	0.86	0.85	0.83	0.77	1.01	1.25	0.88
2022	0.88	0.85	0.82	0.85	0.85	0.83	0.77	1.01	1.25	0.88
2023	0.88	0.85	0.82	0.85	0.85	0.82	0.76	1.01	1.24	0.88
2024	0.87	0.85	0.82	0.85	0.84	0.82	0.76	1.00	1.24	0.87
2025	0.87	0.85	0.81	0.85	0.84	0.82	0.76	1.00	1.24	0.87
2026	0.87	0.84	0.81	0.85	0.84	0.82	0.75	1.00	1.24	0.87
2027	0.87	0.84	0.81	0.85	0.84	0.82	0.75	0.99	1.24	0.86
2028	0.86	0.84	0.81	0.85	0.83	0.82	0.74	0.99	1.24	0.86
2029	0.86	0.83	0.81	0.85	0.83	0.82	0.74	0.99	1.24	0.86
2030	0.86	0.83	0.81	0.84	0.83	0.82	0.74	0.99	1.24	0.85
2031	0.85	0.83	0.80	0.84	0.82	0.81	0.73	0.98	1.24	0.85
2032	0.85	0.82	0.80	0.84	0.82	0.81	0.73	0.98	1.24	0.85
2033	0.85	0.82	0.80	0.84	0.82	0.81	0.73	0.98	1.24	0.85
2034	0.84	0.82	0.80	0.84	0.82	0.81	0.72	0.97	1.23	0.84
2035	0.84	0.82	0.80	0.84	0.81	0.81	0.72	0.97	1.23	0.84
2036	0.84	0.81	0.80	0.84	0.81	0.81	0.72	0.97	1.23	0.84
2037	0.83	0.81	0.79	0.84	0.81	0.81	0.71	0.96	1.23	0.83
2038	0.83	0.81	0.79	0.83	0.81	0.81	0.71	0.96	1.23	0.83
2039	0.83	0.80	0.79	0.83	0.80	0.80	0.71	0.96	1.23	0.83
2040	0.82	0.80	0.79	0.83	0.80	0.80	0.70	0.96	1.23	0.82

* Base year = 2014

7B.2.3 Assigning Commercial Warm Air Furnace Equipment Characteristics to Sampled Buildings

To determine the heating load of each sample building, DOE represented the existing CWAF by assigning an input capacity and TE to the existing CWAF in the CBECS 2003 sample building units and, for CWAFs residential applications, in the RECS 2009 sample building units. DOE assumed that all CWAFs have an input capacity of 250 kBtu/hr, and that the size of the existing product would be the same as for the new CWAF equipment.

7B.2.3.1 Derivation of Existing TE

The TE of existing equipment that has already been installed is required in order to calculate the building heating load. DOE did not have any historical distributions of efficiencies for existing CWAF. For the year 1978, DOE used average AFUE data that was provided for both

residential gas-fired furnaces and oil-fired furnaces,[3] and assumed this would be the same for CWAF at that time for TE. Table 7B.2.12 shows the shipment weighted efficiencies available from 1978 to 2009.

Table 7B.2.12 Shipment-Weighted TE for Gas-Fired and Oil-Fired Commercial Warm Air Furnaces

Year	Gas-Fired CWAF	Oil-Fired CWAF
	TE	TE
1978	65	65
1979	66	66
1980	67	67
1981	68	68
1982	69	69
1983	70	70
1984	71	71
1985	72	72
1986	73	73
1987	74	74
1988	75	75
1989	76	76
1990	77	77
1991	78	78
1992	79	79
1993	80	80
1994	80	81
1995	80	81
1996	80	81
1997	80	81
1998	80	81
1999	80	81
2000	80	81
2001	80	81
2002	80	81
2003	80	81
2004	80	81
2005	80	81
2006	80	81
2007	80	81
2008	80	81
2009	80	81

7B.3 DETERMINATION OF ANNUAL ELECTRICAL ENERGY CONSUMPTION

The Department calculated CWAF electricity consumption as follows:

$$ElecUse_{TOTAL} = ElecPower_{ElecComp} \times BOH_{SH} + ElecUse_{Aux} + DiffElecUse_{fan} + (8760 - BOH_{SH}) \times StbyE$$

Eq. 7B.8

Where:

$ElecPower_{ElecComp}$ = power of electrical components required during CWAF operation, (kW) (see section 7B.3.1),
BOH_{SH} = operating hours of the electrical components, which are the same as the CWAF BOH, (h) as defined in section 7B.2.1,
$ElecUse_{Aux}$ = electricity use of the auxiliary equipment, such as condensate pumps and heat tape, (kWh) (see section 7B.3.2),
$DiffElecUse_{Fan}$ = differential of electricity use of the furnace fan during cooling and continuous fan circulation, (kWh) (see section 7B.3.3),
8760 = hours in one year, and
StbyE = power consumption during standby (kW), assumed to be 10 watts.

7B.3.1 Furnace Electricity Consumption (Heating Season)

The active mode electricity consumption takes into account the electricity consumption of the electrical components of the CWAF (such as blower, the draft inducer, and the ignitor).

The average annual electrical energy consumption of electrical components required during CWAF operation (E_{AE}, which is equal to $ElecPower_{ElecComp}$ times BOH_{SH} in equation Eq. 7B.8) is calculated as:

$$E_{AE} = BOH_{SH}(y_P PE + y_{IG} PE_{IG} + yBE)$$

Eq. 7B.9

Where:

$BOHs_H$ = as defined in section 7B.2.1,
y_P = as defined in section 7B.2.1, which is equal to $1 + t_P / t_{ON}$,
PE = as defined in section 7B.2.1,
y_{IG} = as defined in section 7B.2.1, which is equal to t_{IG} / t_{ON},
PE_{IG} = as defined in section 7B.2.1,
y = as defined in section 7B.2.1, which is equal to $1 + (t^+ - t^-) / t_{ON}$,
BE = as defined in section 7B.2.1,
t_p = draft inducer post-purge time,
t_{ON} = burner on-time per cycle,
t_{IG} = ignition on-time interval,
t^+ = blower off-delay, and
t^- = blower on-delay.

The draft inducer has an average electrical consumption (*PE*) of 100 watts for gas-fired CWAF and 220 watts for oil-fired CWAF based on furnace model data.

Generally, induced- and forced-draft fans operate during post-purge, as well as during the burner on-cycle. In general, the post-purge can range from 0 to 30 seconds. For this analysis, DOE used a draft inducer post-purge time (t_P) of 30 seconds to calculate y_P.

DOE assumed that t_{ON} is equal to 3.87 minutes to calculate y_P, y_{IG}, and y, based on the residential furnace test procedure assumption.[4]

CWAF utilize spark ignition, hot surface ignition, and direct spark to pilot. Spark ignition is generally used in condensing products while the others are used in non-condensing products. In this analysis, DOE assumed spark ignition for all equipment with PE_{IG} equal to 25 watts and t_{IG} equal to 4.8 seconds to calculate y_{IG}.

DOE calculated the ratio of blower on-time to burner on-time (y) using t^+ (blower off-delay) and t^- (blower on-delay). For this analysis, DOE assumed the shut-down time delay t^+ is 30 seconds and the start-up time delay t^- is 0 seconds.

The electricity consumption (and overall efficiency) of a blower motor depends on the speed at which the motor operates, the external static pressure difference across the blower, and the airflow through the blower. For this analysis, DOE assumed that on average the fan power (BE) is 1026 W for non-condensing CWAF based on CUAC energy use analysis calculations, which includes a fraction of installations with variable frequency drives.[5] Because of the increased static pressure for condensing CWAF, DOE calculated the fan power for condensing CWAF to be 1073 W. DOE calculated this by using the ratio between non-condensing and condensing FER values for residential furnace fans in DOE's final rule standards rulemaking.[6] This ratio results in a 4.6 percent increase in electricity use for the condensing furnace fan at 2000 cubic feet per minute (CFM).

7B.3.2 Electricity Consumption Auxiliary Equipment

DOE also included the electricity use of auxiliary equipment, such as condensate pumps and heat tape, which are sometimes installed with higher-efficiency products. The electricity consumption of the auxiliary equipment ($ElecUse_{Aux}$) is added to the total electricity consumption. If a household required a condensate pump, DOE assumed that it consumes 60 watts and operates at the same time as the burner. If a household required heat tape to prevent the condensate withdrawal pipe from freezing, DOE assumed that it consumes 7 watts per foot (on average 42 watts total) and operates only when the average monthly outside temperature drops below 32 °F. Details of how DOE determined whether a household required a condensate pump or heat tape can be found in chapter 8.

7B.3.3 Non-Heating Furnace Fan Energy Use Differential

DOE accounted for the effect of condensing CWAF on the operation of cooling equipment and the use of furnace fan for ventilation. Condensing CWAF have a secondary heat exchanger, which tends to increase the internal static pressure of the circulating airflow stream. Increased internal static pressure typically increases the wattage required by the furnace blower

to produce the same airflow output. Because most central air conditioners use the furnace circulating blower, the blower will consume more electricity and the cooling system needs to operate more to compensate for the additional heat contributed by the blower. The furnace circulating blower is also often used for building ventilation. The cooling energy use differential between the baseline equipment and condensing equipment is then calculated by the following formula:

$$DiffElecUse_{fan} = (COH + VOH) \times FanPower_{differential} + COHdiff \times CAC_Power$$

Eq. 7B.10

Where:

COH = cooling operating hours, hour/year,
VOH = cooling operating hours, hour/year,
$FanPower_{differential}$ = difference between non-condensing and condensing furnace fan power in cooling and ventilation operating modes, kWh/year,
COHdiff = difference cooling operating hours between non-condensing and condensing furnace, and
CAC_Power = CAC power consumption, kWh/year.

The cooling operating hours are calculated using the following formula:

$$COH = \frac{BCL}{CoolingCapacity}$$

Eq. 7B.11

Where:

COH = cooling operating hours, hour/year,
BCL = building cooling load, MMBtu/year, and
CoolingCapacity = cooling capacity of air conditioner, Btu/h (assumed to be 10 tons or 120 kBtu/h).

The BCL is derived using the EIA's CBECS 2003 or RECS 2009 cooling energy use data for the sample buildings as follows:

$$BCL = \frac{CoolingEnergyUse \times EER_{ex}}{CoolingCapacity_{ex}} \times Adj_Factor$$

Eq. 7B.12

Where:

CoolingEnergyUse = annual electricity consumption for cooling based on CBECS 2003 and RECS 2009 (kBtu/yr), see Table 7B.3.1,
EER_{ex} = EER of the existing central air conditioner (assumed to be vary by vintage of CUAC equipment),

CoolingCapacity = cooling capacity of existing central air conditioner, Btu/h (assumed to be 10 tons), and
Adj_Factor = adjustment factors (discussed below).

Table 7B.3.1 Range of Original Cooling Energy Use Based on CBECS 2003 and RECS 2009 Data for Each CWAF Equipment Class, MMBtu/year

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0	2290.4	44.8	0.0	4.1	16.8	45.3	181.8
Oil-Fired CWAF	0	1568.0	40.2	0.0	0.0	4.6	21.6	184.8

DOE made adjustments to the BCL to reflect the expectation that the buildings in 2019 will have a somewhat different BCL than the buildings in the CBECS 2003 and RECS 2009 CWAF sample. The first adjustment involves multiplying the calculated BCL for each CBECS 2003 or RECS 2009 building by the building shell efficiency index[c] based on information from the NEMS simulation performed for *AEO 2015*. This factor differs for space cooling applications, commercial and residential buildings, as well as for new construction and replacement buildings. The factors applied in the analysis for replacements in commercial buildings range from 0.83 to 0.96 in the case of space cooling (depending on the census division of the building). For commercial new constructions, the factor ranges from 0.51 to 0.89 for space cooling. For residential buildings, in the case of space cooling the factor is 0.97 for replacements and 1.01 for new constructions. This means that buildings on average will have lower space cooling loads compared to commercial buildings in 2009 or commercial buildings in 2003, except for new construction residential buildings.

DOE also accounted for future changes and for regional differences in cooling degree days (CDDs). These adjustments to the BHL were performed using CDDs reported in CBECS 2003 and RECS 2009 for each building and National Oceanic and Atmospheric Administration (NOAA) data by region, which reflect historical average climate conditions.

The regional adjustment factors are calculated using the following equation:

$$Adj_{Factor_{average_{climate}}} = \frac{CDD_{10_yr_avg}}{CDD_{bldg_yr}}$$

Eq. 7B.13

Where:

[c] 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 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).

$CDD_{10_yr_avg}$ = 10-year average CDD (2004–2013) based on NOAA data,[2] also for the specific region where the building is located,[d] and
CDD_{bldg_yr} = CDD in 2003 for commercial buildings, or 2009 for residential buildings, for the specific region where the building is located.

The regional CDD factors for commercial buildings range from 0.98 to 1.30, with an average of 1.10. The regional CDD factors for residential buildings range from 0.56 to 1.27, with an average of 0.82.

DOE used *AEO 2015* CDD projections to account for future climate trends. This adjustment account for the change in CDDs from 2013 to the year the standard is planned to take effect, 2019.

Table 7B.3.2 shows the results for the range in adjusted cooling loads among sample buildings and households.

Table 7B.3.2 Range of Adjusted Cooling Loads for Each Equipment Class, MMBtu/year

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0	5658.3	118.8	0.0	10.9	45.2	119.7	480.3
Oil-Fired CWAF	0	5816.0	113.2	0.0	0.0	12.6	55.1	502.9

Table 7B.3.3 shows the results for the baseline cooling furnace operating hours among sample buildings and households.

Table 7B.3.3 Range of Baseline Cooling Annual Operating Hours for Each Equipment Class, hours

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0	8755.7	5570.4	203.0	2916.7	6839.1	8198.6	8661.4
Oil-Fired CWAF	0	8755.8	5575.0	203.0	2916.7	6839.1	8205.4	8662.6

DOE calculated the $FanPower_{differential}$ by using the ratio between non-condensing and condensing FER values for residential furnace fans in DOE's final rule standards rulemaking.[6] This ratio results in a 4.6 percent increase in electricity use for the condensing furnace fan at 2000 cubic feet per minute (CFM). The non-condensing furnace fan power is assumed to be 931 watts in cooling and ventilation mode based on the average fan power values from the CUAC

[d] The last 10-year average is used to normalize the CDD values, an approach that is similar to what is done in *AEO 2015*.

analysis, which includes a fraction of installations with variable frequency drives. The condensing furnace fan is assumed to consume 43 watts more.[5]

The *COHdiff* is the difference cooling operating hours between non-condensing and condensing furnace. It is calculated by assuming that all additional heat from the motor needs to be compensated with additional cooling. The cooling capacity of the system is assumed to be 10 tons or 120 kBtu/h. The additional power (*CAC_Power*) is calculated by assuming that the average efficiency of the cooling system in 2019 will be 12.0 EER.[5]

The ventilation operating hours are calculated using the following formula:

$$VOH = \frac{CoolingEnergyUse}{Vent_Power}$$

Eq. 7B.14

Where:

CoolingEnergyUse = annual electricity consumption for cooling based on CBECS 2003[e] (kBtu/yr), and

Vent_Power = furnace fan power consumption during ventilation operating mode, kWh/year (assumed to be the same as furnace fan power consumption during cooling mode).

The differential in cooling and ventilation electricity consumption between the non-condensing equipment and condensing equipment is shown in Table 7B.3.4. It is included in the total electricity use shown in chapter 7.

Table 7B.3.4 Range of Additional Electricity Use for Condensing Furnace Designs in Cooling and Ventilation Mode, kWh/yr

Equipment Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired CWAF	0	857.1	268.1	3.2	38.0	96.8	508.1	565.8
Oil-Fired CWAF	0	612.8	269.7	3.8	34.6	258.3	491.5	543.8

[e] This data is not available in RECS 2009.

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APPENDIX 7C. MAPPING OF WEATHER STATION DATA TO CBECS AND RECS BUILDINGS

TABLE OF CONTENTS

7C.1 INTRODUCTION 7C-1
7C.2 MAPPING METHODOLOGY 7C-1
7C.3 MAPPING RESULTS 7C-2
7C.3.1 Developing Monthly Heating and Cooling Degree Day Fractions 7C-9
7C.3.2 Monthly Average Outdoor Temperature Data by Weather Station 7C-36

LIST OF TABLES

Table 7C.3.1 Weather Station Mapping Statistics, Heating and Cooling ODT, and Average Outdoor Temperature 7C-2
Table 7C.3.2 Weather Station Monthly Heating Degree Day Data (10-Year Average) 7C-9
Table 7C.3.3 Weather Station Monthly Cooling Degree Day Data (10-Year Average) 7C-16
Table 7C.3.4 Weather Station Monthly Heating Degree Day Data Fractions (10-Year Average) 7C-22
Table 7C.3.5 Weather Station Monthly Cooling Degree Day Data Fractions (10-Year Average) 7C-29
Table 7C.3.6 Weather Station Monthly Average Outdoor Temperature (1970-2000) 7C-36

APPENDIX 7C. MAPPING OF WEATHER STATION DATA TO CBECS AND RECS BUILDINGS

7C.1 INTRODUCTION

The Energy Information Administration's (EIA) 2003 Commercial Building Energy Consumption Survey (CBECS 2003)[1] and 2009 Residential Energy Consumption Survey (RECS 2009)[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 commercial warm air furnace (CWAF) equipment 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 CBECS 2003 and RECS 2009 by month. Monthly energy use is combined with monthly energy prices to find the monthly operating cost (see appendix 7B and appendix 8C). Average monthly outdoor temperature where used to determine hours of operation of heat tape as described in 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 CBECS building and RECS household.[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 2003 (for the CBECS sample) and year 2009 (for the RECS sample), for these weather stations.[3] The 2003 and 2009 heating and cooling degree days match the period used to determine the degree-days in CBECS 2003 and in RECS 2009, 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. CBECS 2003and RECS 2009 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 CBECS 2003/RECS 2009 data to the weather data. Eq. 7C.1 calculates the U.S. weather station closest (or with minimum "distance") to the CBECS 2003/RECS 2009 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 CBECS 2003/RECS 2009 data,
CDD_1 = cooling degree days from U.S. weather data, and
CDD_2 = cooling degree days from CBECS 2003/RECS 2009 data.

7C.3 MAPPING RESULTS

Table 7C.3.1 shows the imputation results for all CBECS 2003 and RECS 2009 locations. Note that some U.S. weather station data match with several of the CBECS 2003/RECS 2009 weather data. The number of CBECS 2003/RECS 2009 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.

Table 7C.3.1 Weather Station Mapping Statistics, Heating and Cooling ODT, and Average Outdoor Temperature

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
AK	Anchorage	ANC	10335	2	8	9300	25	1	-18	68	36
AK	Bethel	BET	12530	0	1	11261	14	1	-24	68	30
AK	Cold Bay	CDB	9668	0	2	-	-	-	10	57	38
AK	Cordova	CDV	9511	0	2	8332	0	1	1	67	38
AK	Homer	HOM	9817	0	10	-	-	-	4	62	38
AK	Juneau	JNU	8536	6	2	8198	2	1	1	70	42
AK	Kenai	ENA	10423	0	1	-	-	-	-14	65	36
AK	Ketchikan	KTN	7359	68	2	7160	0	11	20	68	38
AK	King Salmon	AKN	11088	0	1	9773	10	1	-19	67	35
AK	Kodiak	ADQ	8903	0	1	8051	15	1	13	65	41
AK	Sitka	SIT	-	-	-	6515	2	3	21	64	42
AK	St Paul Island	SNP	11420	0	4	-	-	-	3	52	35
AK	Talkeetna	TKA	-	-	-	8824	85	1	-21	73	34
AK	Valdez	VWS	7074	23	2	-	-	-	7	66	38
AK	Yakutat	YAK	9295	1	1	-	-	-	2	63	40
AL	Birmingham	BHM	2605	1958	25	2664	1874	20	21	93	62
AL	Huntsville	HSV	2982	1863	26	3121	1633	24	16	92	61
AL	Mobile	MOB	1594	2681	59	1667	2695	6	29	92	67
AL	Montgomery	MGM	2137	2367	3	2248	2212	9	25	94	65
AL	Muscle Shoals	MSL	2948	1773	12	3138	1533	9	21	93	61
AL	Tuscaloosa	TCL	2349	2136	10	2510	2047	13	23	93	64
AR	Fayetteville	FYV	3957	1185	48	4017	1202	12	12	93	58
AR	Fort Smith	FSM	3174	1906	3	-	-	-	17	96	61
AR	Little Rock	LIT	2946	1943	27	-	-	-	20	95	62
AR	Texarkana	TXK	2573	2006	10	2259	2573	5	23	96	61
AZ	Douglas	DUG	2160	2204	27	2340	2206	7	31	98	61
AZ	Flagstaff	FLG	6741	176	2	-	-	-	4	83	46
AZ	Phoenix	PHX	807	4942	26	702	4975	24	34	108	74

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
AZ	Tucson	TUS	1268	3626	85	1279	3480	15	32	104	69
AZ	Winslow	INW	4233	1395	4	4377	1459	16	10	93	55
AZ	Yuma	NYL	671	4757	82	558	4747	16	39	109	75
CA	Bakersfield	BFL	1873	2644	177	1931	2692	25	32	101	65
CA	Blythe	BLH	968	4580	8	853	4649	4	33	112	71
CA	Eureka	EKA	5137	2	2	4670	12	3	33	65	53
CA	Fresno	FAT	2239	2390	50	2147	2412	48	30	101	63
CA	Los Angeles	LAX	1294	569	117	1237	677	99	43	80	63
CA	Mt Shasta	MHS	5474	433	5	5294	418	24	21	88	49
CA	Paso Robles	PRB	2676	1095	144	2699	1219	14	29	98	58
CA	Red Bluff	RBL	2452	2122	70	2635	2097	8	32	102	62
CA	Redding	RDD	2750	2086	63	-	-	-	31	102	62
CA	Sacramento	SAC	2531	1357	30	2417	1463	49	32	98	61
CA	San Diego	SAN	1050	813	540	1060	724	98	44	81	64
CA	San Francisco	SFO	2614	220	278	2494	269	64	38	78	57
CA	Stockton	SCK	2451	1468	122	2497	1525	21	30	98	62
CO	Alamosa	ALS	8229	49	27	7762	151	4	-16	82	41
CO	Colorado Spring	COS	6301	356	90	5846	603	4	2	88	48
CO	Denver	DEN	5988	541	69	5796	800	6	1	92	50
CO	Eagle	EGE	7593	124	15	6889	369	5	-7	86	41
CO	Pueblo	PUB	5427	818	77	4891	1115	2	0	96	52
CO	Trinidad	TAD	5323	719	17	5109	944	31	3	90	51
CT	Bridgeport	BDR	5484	669	57	5800	824	47	9	85	52
CT	Hartford	BDL	6072	610	94	6359	723	32	7	88	50
DC	Washington	DCA	4124	1427	39	4338	1288	49	17	93	58
DE	Wilmington	ILG	4789	1031	14	5206	1010	15	14	89	54
FL	Daytona Beach	DAB	753	3321	99	849	3153	35	35	91	71
FL	Fort Myers	FMY	294	4151	63	370	4062	28	44	93	75
FL	Ft Lauderdale	FLL	118	4839	30	194	4622	10	46	91	75
FL	Gainesville	GNV	1181	2789	118	1288	2700	26	31	92	69
FL	Jacksonville	JAX	1339	2772	60	1450	2605	8	32	93	68
FL	Key West	EYW	108	5017	11	127	5071	11	57	89	78
FL	Melbourne	MLB	526	3718	80	632	3469	16	43	91	73
FL	Miami	MIA	109	4914	2	166	4721	9	47	91	77
FL	Orlando	MCO	588	3620	103	661	3528	11	38	93	73
FL	Pensacola	PNS	1443	2729	44	1565	2642	10	29	92	68
FL	Tallahassee	TLH	1574	2802	31	1673	2538	2	30	94	68
FL	Tampa	TPA	496	3876	112	639	3666	39	40	91	73
FL	Vero Beach	VRB	477	3604	26	544	3582	16	43	91	73
FL	West Palm Beach	PBI	239	4314	169	294	4388	26	45	90	75
GA	Albany	ABY	1767	2686	5	-	-	-	29	95	66
GA	Athens	AHN	2882	1903	253	2831	1564	45	22	93	62
GA	Atlanta	ATL	2813	1838	87	2732	1614	33	22	92	62
GA	Augusta	AGS	2475	2068	55	2561	1820	9	23	95	63
GA	Brunswick	SSI	-	-	-	1557	2513	15	32	91	69
GA	Columbus	CSG	2183	2194	2	2053	2284	2	24	94	65
GA	Macon	MCN	2288	2133	17	2261	2195	34	25	94	64
GA	Savannah	SAV	1739	2497	21	1851	2434	5	27	93	66

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
GA	Waycross	AYS				1424	2689	17	29	94	67
HI	Hilo-Hawaii	ITO	0	3050	14	0	3669	7	62	85	74
HI	Honolulu-Oahu	HNL	0	4816	14	0	5030	4	63	89	78
HI	Kahului-Maui	OGG	1	3746	21	0	4270	2	61	88	76
HI	Lihue-Kauai	LIH	2	3611	5	0	4136	3	62	85	76
IA	Burlington	BRL	5687	810	24	6031	870	10	-3	91	50
IA	Cedar Rapids	CID	6977	419	15	6861	721	17	-5	89	47
IA	Des Moines	DSM	6124	898	33	6263	1130	2	-5	90	50
IA	Dubuque	DBQ	7204	345	1	7189	602	10	-7	86	47
IA	Mason City	MCW	7856	338	15	7699	556	16	-11	88	47
IA	Ottumwa	OTM	6317	588	43	6335	883	12	-4	92	50
IA	Sioux City	SUX	6913	678	75	6699	833	17	-7	90	48
IA	Waterloo	ALO	7253	448	58	6962	849	8	-10	89	47
ID	Boise	BOI	5592	1199	9	4877	1316	1	10	95	52
ID	Burley	BYI	6697	397	1	5978	568	15	2	90	47
ID	Idaho Falls	IDA	-	-	-	7069	409	8	-6	89	47
ID	Lewiston	LWS	5386	1008	3	4803	1081	15	6	94	52
ID	Pocatello	PIH	7463	321	17	6443	675	16	-1	91	47
IL	Chicago	ORD	6417	585	40	6446	697	37	0	90	49
IL	Moline	MLI	6250	636	35	6207	933	17	-4	91	50
IL	Peoria	PIA	5841	752	62	5846	906	46	-4	90	51
IL	Quincy	UIN	5460	849	12	5580	938	7	3	90	51
IL	Rockford	RFD	6738	433	58	6738	732	52	-4	89	48
IL	Springfield	SPI	5234	933	41	5549	916	10	2	91	53
IN	Evansville	EVV	4397	1283	13	4530	1143	22	9	92	56
IN	Fort Wayne	FWA	6077	601	41	6481	576	24	1	88	50
IN	Indianapolis	IND	5203	953	22	5551	883	7	2	89	53
IN	South Bend	SBN	6426	545	54	6416	626	10	1	88	50
IN	West Lafayette	LAF	5436	826	32	5690	825	32	3	90	50
KS	Concordia	CNK	5558	1094	18	5231	1465	14	3	96	54
KS	Dodge City	DDC	4975	1257	27	4926	1490	8	5	97	55
KS	Garden City	GCK	5014	1154	31	5025	1367	24	4	97	55
KS	Goodland	GLD	6016	722	11	5494	1096	22	0	94	51
KS	Russell	RSL	5298	1194	46	5157	1459	3	4	96	54
KS	Salina	SLN	-	-	-	4608	1771	8	5	98	56
KS	Topeka	TOP	4968	1195	9	4887	1499	21	4	94	54
KS	Wichita	ICT	4552	1506	68	4502	1620	56	7	97	56
KY	Bowling Green	BWG	3808	1407	52	4087	1183	34	10	91	57
KY	Jackson	JKL	4237	984	15	4299	917	5	14	87	56
KY	Lexington	LEX	4670	1020	40	4750	954	8	8	89	55
KY	Louisville	SDF	4155	1316	29	4201	1307	9	10	91	57
KY	Paducah	PAH	4198	1239	39	4365	1258	10	12	93	57
LA	Baton Rouge	BTR	1404	2985	24	1683	2674	17	29	93	67
LA	Lafayette	LFT	1296	3086	3	1581	2787	14	30	93	68
LA	Lake Charles	LCH	1380	2980	10	1525	2823	18	31	93	68
LA	Monroe	MLU	2118	2547	11	2381	2353	7	25	95	66
LA	New Orleans	MSY	1156	3221	35	1327	3162	11	33	92	69
LA	Shreveport	SHV	-	-	-	2143	2504	3	25	95	66

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
MA	Boston	BOS	5694	581	243	6067	745	13	9	87	52
MA	Worcester	ORH	6699	370	258	7006	479	32	4	83	47
MD	Baltimore	BWI	4745	1088	34	5010	1020	22	13	91	55
MD	Salisbury	SBY	4345	1149	19	4870	1010	55	16	90	57
ME	Augusta	AUG	7487	276	18	7746	420	11	23	95	63
ME	Bangor	BGR	8098	246	19	8161	403	21	-6	84	46
ME	Caribou	CAR	9415	149	13	9754	214	2	-13	82	39
ME	Houlton	HUL	9316	178	24	9458	238	3	-13	85	40
ME	Portland	PWM	7107	294	108	7508	355	21	-1	83	46
MI	Alpena	APN	-	-	-	8468	241	7	-6	84	43
MI	Detroit	DTW	6224	588	81	6398	659	19	6	87	50
MI	Flint	FNT	7068	328	40	6891	494	22	1	86	47
MI	Grand Rapids	GRR	6580	444	35	7030	487	17	5	86	48
MI	Houghton Lake	HTL	-	-	-	8311	197	1	1	85	43
MI	Jackson	JXN	6585	420	11	6955	392	2	14	87	56
MI	Lansing	LAN	6830	372	36	7239	385	10	1	86	47
MI	Marquette	MQT	-	-	-	9288	248	3	-8	83	39
MI	Muskegon	MKG	6719	371	38	6740	516	32	6	83	47
MI	Saginaw	MBS	6960	350	19	7313	406	8	4	87	47
MI	Sault St Marie	SSM	-	-	-	8809	168	2	-8	80	40
MI	Traverse City	TVC	7695	253	14	7826	345	13	1	86	47
MN	Alexandria	AXN	8922	340	8	8675	553	9	-16	86	42
MN	Duluth	DLH	9517	118	10	-	-	-	-16	81	39
MN	Hibbing	HIB	10159	64	4	-	-	-	-20	81	37
MN	Int'l Falls	INL	10648	72	8	10115	220	5	-25	83	37
MN	Minneapolis	MSP	7613	646	48	7538	880	3	-12	88	45
MN	Rochester	RST	7884	321	9	7957	512	16	-12	85	43
MN	Saint Cloud	STC	8704	301	74	8489	496	2	-11	88	42
MO	Columbia	COU	4999	958	125	5010	1151	5	4	92	54
MO	Joplin	JLN	4216	1382	98	3974	1677	11	10	94	56
MO	Kansas City	MCI	5084	1093	213	-	-	-	6	93	54
MO	Saint Louis	STL	4438	1457	70	4445	1485	3	6	93	56
MO	Springfield	SGF	4596	1114	180	4529	1321	6	2	91	53
MS	Greenwood	GWO	2376	2250	1	-	-	-	20	94	61
MS	McComb	MCB	1833	2472	34	-	-	-	26	92	64
MS	Tupelo	TUP	2842	1947	20	3002	1722	4	19	94	61
MT	Billings	BIL	6948	627	9	-	-	-	-10	90	47
MT	Butte	BTM	-	-	-	8967	180	6	-17	84	40
MT	Cut Bank	CTB	-	-	-	8419	313	6	-20	84	40
MT	Great Falls	GTF	7941	300	1	7431	576	5	-15	89	44
MT	Havre	HVR	-	-	-	8190	683	6	-11	90	44
MT	Helena	HLN	7704	444	1	7066	798	2	-16	87	44
MT	Kalispell	FCA	-	-	-	7681	317	2	-7	86	43
MT	Lewistown	LWT	-	-	-	7878	493	4	-16	86	44
MT	Miles City	MLS	7700	716	1	-	-	-	-15	93	46
MT	Missoula	MSO	7588	355	2	7073	518	1	-6	88	45
NC	Asheville	AVL	4194	768	23	-	-	-	14	86	55
NC	Cape Hatteras	HAT	-	-	-	2446	1687	30	29	86	63

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
NC	Charlotte	CLT	3346	1611	71	3311	1308	50	22	91	61
NC	Greensboro	GSO	3605	1510	41	3622	1210	28	18	90	58
NC	Hickory	HKY	3593	1353	42	3703	1032	31	18	90	58
NC	New Bern	EWN	2769	1788	16	2797	1818	25	24	92	64
NC	Raleigh Durham	RDU	3164	1865	55	3413	1459	42	20	92	60
NC	Wilmington	ILM	2521	1937	14	2625	1864	2	14	89	54
ND	Bismarck	BIS	9130	332	16	8505	738	9	-19	90	42
ND	Devil's Lake	P11	10245	236	8	9544	454	3	-21	87	40
ND	Fargo	FAR	9304	362	17	8862	616	17	-18	88	42
ND	Grand Forks	GFK	9928	269	8	9575	417	3	-22	89	40
ND	Minot	MOT	9559	314	9	9066	609	20	-20	89	41
ND	Williston	ISN	9721	297	8	9603	670	14	-21	92	41
NE	Grand Island	GRI	6431	788	26	5942	1059	16	-3	93	50
NE	Lincoln	LNK	6159	912	14	6027	1131	5	-2	94	51
NE	Norfolk	OFK	6789	643	4	6312	962	8	-4	92	49
NE	North Platte	LBF	6946	534	14	6249	926	2	-4	92	49
NE	Omaha	OMA	6288	851	32	6130	1158	3	-3	90	51
NE	Scottsbluff	BFF	6689	579	6	6293	867	4	-3	92	48
NE	Valentine	VTN	7279	527	2	6861	917	4	-8	94	47
NH	Concord	CON	7462	325	5	7666	541	2	-3	87	46
NH	Lebanon	LEB	7312	371	18	8434	362	6	-3	86	46
NJ	Atlantic City	ACY	4693	994	57	5328	1012	58	13	89	54
NJ	Newark	EWR	4790	1021	147	5165	1098	38	14	91	55
NM	Albuquerque	ABQ	3823	1435	17	-	-	-	16	93	57
NM	Carlsbad	CNM	2398	2376	2	-	-	-	19	98	63
NM	Clayton	CAO	4517	1143	31	4390	1025	9	9	91	53
NM	Gallup	GUP	6134	442	6	5827	550	8	5	87	53
NM	Roswell	ROW	3098	1961	7	-	-	-	18	96	61
NV	Elko	EKO	6948	450	1	6266	597	25	-2	92	46
NV	Ely	ELY	7925	125	4	6856	404	8	-4	87	45
NV	Las Vegas	LAS	1882	3818	66	1882	3846	41	28	106	68
NV	Lovelock	LOL	-	-	-	5463	975	8	12	97	50
NV	Reno	RNO	-	-	-	4556	1184	11	10	92	51
NV	Tonopah	TPH	5298	874	5	5102	1127	4	10	92	51
NV	Winnemucca	WMC	6236	611	2	5696	736	13	3	94	49
NY	Albany	ALB	6644	433	149	7023	613	12	29	95	66
NY	Binghamton	BGM	7067	261	59	7580	316	3	1	82	46
NY	Buffalo	BUF	6651	361	54	6909	429	18	6	84	48
NY	Glens Falls	GFL	7612	285	26	8024	376	15	-5	85	46
NY	Massena	MSS	7980	298	2	8752	381	6	-8	84	46
NY	New York	LGA	4647	1041	469	5025	1155	43	15	89	55
NY	Rochester	ROC	6765	315	46	6986	477	9	-12	85	43
NY	Syracuse	SYR	6687	439	23	6939	522	15	2	86	47
NY	Utica	UCA	-	-	-	7580	386	33	-6	85	47
NY	Watertown	ART	7707	298	11	8018	379	5	-6	83	46
OH	Akron Canton	CAK	6131	497	6	6361	543	17	6	86	50
OH	Cincinnati	CVG	4950	874	13	5229	838	70	6	90	54
OH	Cleveland	CLE	5833	664	44	6077	685	50	5	87	50

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
OH	Columbus	CMH	5243	874	32	5504	765	46	24	94	65
OH	Dayton	DAY	5602	732	45	5832	676	65	4	88	52
OH	Findlay	FDY	5901	698	34	6156	643	52	3	87	50
OH	Mansfield	MFD	6214	468	10	6493	476	7	5	85	49
OH	Toledo	TOL	6283	592	32	6311	630	34	1	88	50
OH	Youngstown	YNG	6239	443	8	6566	394	6	4	86	49
OK	Hobart	HBR	3392	2034	1	3439	2129	6	16	101	60
OK	McAlester	MLC	3136	1845	6	3082	1973	47	19	96	60
OK	Oklahoma City	OKC	3519	1849	37	3529	1881	46	13	96	60
OK	Tulsa	TUL	3608	1885	24	3473	2053	13	13	97	61
OR	Astoria	AST	4871	39	4	-	-	-	29	72	51
OR	Baker	BKE	7529	220	2	6650	315	30	6	91	45
OR	Eugene	EUG	4999	331	89	4269	350	6	22	88	52
OR	Medford	MFR	-	-	-	4002	1060	4	23	95	54
OR	Pendleton	PDT	5713	720	6	4739	895	32	5	93	52
OR	Portland	PDX	4357	635	32	3908	623	13	-1	83	46
OR	Redmond	RDM	6737	313	17	6020	353	41	9	90	44
OR	Salem	SLE	4660	457	50	4162	467	4	23	88	53
PA	Allentown	ABE	5725	622	22	5935	797	61	9	88	51
PA	Altoona	AOO	6109	433	17	6515	439	12	5	86	50
PA	Bradford	BFD	-	-	-	8029	125	1	-1	80	50
PA	Du Bois	DUJ	6753	254	5	7092	243	9	5	84	50
PA	Erie	ERI	6183	423	9	6496	489	42	9	84	50
PA	Harrisburg	CXY	5097	866	111	5534	856	76	11	90	53
PA	Philadelphia	PHL	4557	1219	46	4894	1269	106	14	90	55
PA	Pittsburgh	PIT	5661	617	6	5892	587	51	5	87	51
PA	Williamsport	IPT	5636	644	69	6233	611	62	7	87	50
RI	Providence	PVD	5717	579	69	5961	742	13	9	86	51
SC	Charleston	CHS	1941	2390	13	1981	2272	3	27	93	65
SC	Columbia	CAE	2561	2220	19	2562	1908	33	4	92	54
SC	Florence	FLO	2541	2061	13	2644	1839	11	25	94	64
SC	Greenville	GSP	3116	1735	42	3108	1379	58	22	91	60
SD	Aberdeen	ABR	8872	329	13	8324	605	33	-15	91	44
SD	Huron	HON	8070	469	105	7598	860	7	-14	91	45
SD	Pierre	PIR	7738	577	36	7200	961	5	-10	95	48
SD	Rapid City	RAP	7738	362	12	7034	905	5	-7	91	47
SD	Sioux Falls	FSD	7670	481	42	7463	724	17	-11	90	45
TN	Bristol	TRI	4267	930	28	4294	860	1	14	87	55
TN	Chattanooga	CHA	3168	1808	35	3206	1498	34	18	92	60
TN	Crossville	CSV	4100	940	33	4240	839	4	15	87	54
TN	Jackson	MKL	3379	1597	22	3603	1394	14	14	87	56
TN	Knoxville	TYS	3643	1392	91	3584	1282	34	19	90	58
TN	Memphis	MEM	2906	2091	3	2954	1961	17	18	94	62
TN	Nashville	BNA	3615	1558	37	3595	1449	23	14	92	59
TX	Abilene	ABI	2359	2494	217	2366	2374	3	20	97	64
TX	Alice	ALI	738	4832	23	1022	3628	28	34	99	72
TX	Amarillo	AMA	4034	1340	33	3787	1410	43	11	95	57
TX	Austin	AUS	1722	3214	45	1888	2793	4	28	96	69

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
TX	Brownsville	BRO	525	4300	20	587	4025	8	39	94	73
TX	College Station	CLL	1404	3476	29	1662	2965	34	29	96	69
TX	Corpus Christi	CRP	811	4058	8	968	3462	8	35	94	72
TX	Dallas-Ft. Worth	DFW	2097	2745	61	2239	2752	25	22	98	66
TX	Del Rio	DRT	1252	3807	29	1338	3406	16	31	98	70
TX	El Paso	ELP	2106	2783	43	2207	2696	4	24	98	65
TX	Galveston	GLS	907	3640	3	1058	3343	17	36	91	71
TX	Houston	IAH	1267	3410	170	1386	3185	20	32	96	69
TX	Laredo	LRD	602	5330	1	826	4348	37	36	101	73
TX	Lubbock	LBB	3178	1965	10	2960	1950	28	15	96	60
TX	Lufkin	LFK	1803	2839	64	1966	2600	7	29	95	69
TX	McAllen	MFE	393	5387	3	707	4415	26	39	99	73
TX	Midland Odessa	MAF	2495	2445	81	2366	2509	15	21	98	63
TX	San Angelo	SJT	2020	2814	56	-	-	-	22	97	65
TX	San Antonio	SAT	1270	3598	28	1485	3039	25	30	97	69
TX	Victoria	VCT	1123	3608	35	1270	3217	10	32	95	70
TX	Waco	ACT	1927	3086	18	1975	2776	16	26	99	67
TX	Wichita Falls	SPS	2838	2394	14	2752	2485	20	18	100	63
UT	Cedar City	CDC	6058	645	56	5606	810	17	5	91	52
UT	Salt Lake City	SLC	5716	1147	29	-	-	-	8	95	52
VA	Lynchburg	LYH	4433	1003	159	4434	884	6	16	90	55
VA	Norfolk	ORF	3330	1659	41	3279	1761	51	-4	92	49
VA	Richmond	RIC	3781	1564	47	3971	1336	51	17	92	58
VA	Roanoke	ROA	3931	1173	34	4216	1002	10	16	90	56
VT	Burlington	BTV	-	-	-	7833	576	1	-3	91	50
VT	Montpelier	MPV	7998	237	12	8793	305	13	-6	83	45
WA	Bellingham	BLI	5568	115	8	5124	54	5	15	76	51
WA	Olympia	OLM	5614	178	24	-	-	-	22	83	50
WA	Quillayute	UIL	5869	44	7	5411	20	2	27	74	49
WA	Seattle Tacoma	SEA	4879	319	94	4509	277	11	26	81	52
WA	Spokane	GEG	6942	599	5	-	-	-	2	89	47
WA	Walla Walla	ALW	5062	1144	12	-	-	-	7	95	54
WA	Yakima	YKM	6204	699	25	-	-	-	5	92	49
WI	Eau Claire	EAU	8208	333	23	7949	623	20	-11	87	44
WI	Green Bay	GRB	8005	275	55	7878	386	18	-9	85	44
WI	Lacrosse	LSE	7334	536	16	7126	854	14	-9	89	47
WI	Madison	MSN	7343	368	66	7356	560	58	-7	87	46
WI	Milwaukee	MKE	6816	474	28	7058	601	48	-4	87	48
WI	Wausau	AUW	8337	277	54	8299	466	14	-12	85	44
WV	Beckley	BKW	5325	404	16	5439	487	2	4	84	52
WV	Charleston	CRW	4443	960	3	4628	789	3	27	93	65
WV	Elkins	EKN	5993	284	3	6291	322	2	6	83	50
WV	Huntington	HTS	4557	922	3	4487	881	6	10	89	55
WV	Martinsburg	MRB	5046	854	63	5411	783	19	10	91	54
WV	Morgantown	MGW	4957	836	15	5358	628	1	8	87	54
WV	Parkersburg	PKB	4910	850	19	5138	729	4	11	88	54
WY	Casper	CPR	-	-	-	7192	587	6	-5	91	45
WY	Cheyenne	CYS	7390	203	11	6680	577	11	-1	86	45

Station Location		Code	RECS 2009			CBECS 2003			Heating ODT	Cooling ODT	Average Outdoor Temp
State	City		HDD	CDD	Count	HDD	CDD	Count			
WY	Cody	COD	7551	410	2	6992	686	7	-13	87	45
WY	Lander	LND	7743	351	1	-	-	-	-11	87	45
WY	Rock Springs	RKS	8204	230	3	7574	540	2	-3	84	43
WY	Sheridan	SHR	7844	287	2	7401	652	5	-8	90	45
WY	Worland	WRL	7757	467	2	-	-	-	-13	93	45

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. 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 CBECS 2003 and RECS 2009 by month. The monthly energy use is then combined with monthly energy prices to find the monthly operating cost (see appendix 7B and appendix 8C for more details).

Table 7C.3.2 Weather Station Monthly Heating Degree Day Data (10-Year Average)

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AK	Anchorage	ANC	1558	1202	1238	824	510	292	184	234	464	855	1316	1421
AK	Bethel	BET	1914	1447	1684	1155	661	355	273	318	547	1004	1477	1690
AK	Cold Bay	CDB	1167	971	1177	939	755	559	440	388	497	744	944	1068
AK	Cordova	CDV	1225	1001	1074	797	594	413	321	330	490	762	1064	1127
AK	Homer	HOM	1314	1052	1163	829	622	436	320	337	487	786	1127	1201
AK	Juneau	JNU	1138	971	1006	720	492	310	248	280	444	707	980	1110
AK	Kenai	ENA	1608	1223	1285	838	560	362	248	292	478	828	1303	1439
AK	Ketchikan	KTN	930	823	861	666	479	298	212	203	349	600	805	924
AK	King Salmon	AKN	1632	1199	1427	932	620	406	299	307	505	886	1342	1474
AK	Kodiak	ADQ	1090	928	1063	806	621	442	313	294	454	724	969	1059
AK	Sitka	SIT	895	787	868	670	513	354	258	233	345	577	779	876
AK	St Paul Island	SNP	1277	1131	1314	1086	910	671	552	489	572	802	965	1127
AK	Talkeetna	TKA	1636	1267	1281	836	494	234	155	239	504	909	1394	1529
AK	Valdez	VWS	1212	912	952	622	371	194	136	154	319	594	996	1036
AK	Yakutat	YAK	1144	966	1045	796	602	404	297	316	462	719	987	1086
AL	Birmingham	BHM	635	502	261	105	21	0	0	0	4	114	312	563
AL	Huntsville	HSV	722	578	324	135	25	0	0	0	9	145	371	641
AL	Mobile	MOB	427	331	143	45	4	0	0	0	0	55	201	385
AL	Montgomery	MGM	543	417	198	70	9	0	0	0	2	80	265	481
AL	Muscle Shoals	MSL	716	576	317	135	25	0	0	0	7	149	366	640
AL	Tuscaloosa	TCL	606	477	234	95	16	0	0	0	2	110	299	539
AR	Fayetteville	FYV	859	724	446	230	76	2	0	1	32	233	458	803
AR	Fort Smith	FSM	745	599	313	120	26	0	0	0	4	122	343	685
AR	Little Rock	LIT	708	579	310	114	22	0	0	0	3	122	341	654
AR	Texarkana	TXK	606	488	240	84	15	0	0	0	1	96	274	559
AZ	Douglas	DUG	555	426	298	118	14	0	0	0	0	70	307	571
AZ	Flagstaff	FLG	1066	946	828	640	389	136	13	36	202	533	797	1085

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZ	Phoenix	PHX	234	172	63	11	0	0	0	0	0	4	68	283
AZ	Tucson	TUS	342	280	143	44	2	0	0	0	0	15	140	381
AZ	Winslow	INW	918	716	526	311	97	4	0	0	20	256	586	913
AZ	Yuma	NYL	148	128	46	13	0	0	0	0	0	2	54	227
CA	Bakersfield	BFL	484	327	217	133	21	2	0	0	1	51	274	491
CA	Blythe	BLH	271	191	73	13	0	0	0	0	0	5	105	337
CA	Eureka	EKA	557	513	527	496	414	314	276	258	308	365	467	579
CA	Fresno	FAT	527	367	250	146	25	1	0	0	2	52	289	518
CA	Los Angeles	LAX	215	220	200	152	68	13	2	2	4	33	124	251
CA	Mt Shasta	MHS	876	754	707	568	322	126	11	20	114	414	704	908
CA	Paso Robles	PRB	507	418	341	257	89	22	2	2	17	123	344	535
CA	Red Bluff	RBL	530	408	325	218	54	7	0	0	4	86	343	558
CA	Redding	RDD	551	423	351	241	61	9	0	0	5	100	374	583
CA	Sacramento	SAC	544	397	307	211	56	8	0	0	6	84	340	549
CA	San Diego	SAN	214	196	157	107	47	14	2	0	0	15	105	243
CA	San Francisco	SFO	438	344	308	262	187	105	61	52	53	104	266	427
CA	Stockton	SCK	549	393	299	190	45	5	0	0	3	72	327	541
CO	Alamosa	ALS	1432	1202	914	655	390	139	25	63	283	642	1012	1438
CO	Colorado Spring	COS	1025	942	712	503	259	57	7	19	133	443	736	1074
CO	Denver	DEN	1016	946	687	487	252	54	4	10	107	422	727	1075
CO	Eagle	EGE	1322	1086	854	621	367	112	8	26	223	567	918	1305
CO	Pueblo	PUB	1020	895	623	393	151	17	1	4	71	377	698	1062
CO	Trinidad	TAD	960	861	626	412	176	26	2	6	79	357	665	1005
CT	Bridgeport	BDR	1076	920	758	432	190	27	0	1	35	283	544	886
CT	Hartford	BDL	1204	1013	811	441	195	32	1	5	74	376	649	1007
DC	Washington	DCA	885	753	520	245	68	3	0	0	9	191	438	755
DE	Wilmington	ILG	1000	867	639	341	124	13	0	1	26	274	529	849
FL	Daytona Beach	DAB	240	173	75	21	1	0	0	0	0	11	60	172
FL	Fort Myers	FMY	119	65	24	3	0	0	0	0	0	3	15	75
FL	Ft Lauderdale	FLL	61	34	11	1	0	0	0	0	0	0	4	37
FL	Gainesville	GNV	345	249	116	37	1	0	0	0	0	28	120	279
FL	Jacksonville	JAX	385	287	140	51	3	0	0	0	0	32	148	313
FL	Key West	EYW	42	19	5	0	0	0	3	0	0	0	1	16
FL	Melbourne	MLB	181	117	49	15	0	0	0	0	0	9	35	116
FL	Miami	MIA	54	29	8	1	0	0	0	0	0	0	3	31
FL	Orlando	MCO	196	124	48	11	0	0	0	0	0	9	40	134
FL	Pensacola	PNS	394	306	128	36	1	0	0	0	0	36	159	344
FL	Tallahassee	TLH	424	328	149	53	2	0	0	0	0	42	189	368
FL	Tampa	TPA	183	117	46	10	0	0	0	0	0	6	32	129
FL	Vero Beach	VRB	165	107	47	13	0	0	0	0	0	6	26	102
FL	West Palm Beach	PBI	92	53	20	4	0	0	0	0	0	3	11	55
GA	Albany	ABY	469	370	173	56	2	0	0	0	0	51	217	418
GA	Athens	AHN	662	522	304	131	23	0	0	0	4	126	352	602
GA	Atlanta	ATL	650	519	292	118	21	0	0	0	3	110	325	581
GA	Augusta	AGS	598	475	265	106	11	0	0	0	2	100	314	532
GA	Brunswick	SSI	411	328	151	58	3	0	0	0	0	36	154	333
GA	Columbus	CSG	543	421	204	67	5	0	0	0	1	68	240	472
GA	Macon	MCN	563	445	239	91	10	0	0	0	2	89	295	510
GA	Savannah	SAV	478	373	191	69	6	0	0	0	0	50	215	399

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GA	Waycross	AYS	412	317	143	50	2	12	0	0	0	40	180	369
HI	Hilo-Hawaii	ITO	0	0	0	0	0	0	0	0	0	0	0	0
HI	Honolulu-Oahu	HNL	0	0	0	0	0	0	0	0	0	0	0	0
HI	Kahului-Maui	OGG	0	0	0	0	0	0	0	0	0	0	0	0
HI	Lihue-Kauai	LIH	0	0	0	0	0	0	0	0	0	0	0	0
IA	Burlington	BRL	1233	1043	667	337	125	8	1	5	71	339	617	1078
IA	Cedar Rapids	CID	1404	1197	807	441	187	21	5	14	128	450	763	1259
IA	Des Moines	DSM	1310	1109	716	360	128	6	0	4	72	359	697	1159
IA	Dubuque	DBQ	1421	1215	846	475	219	31	6	16	141	466	774	1275
IA	Mason City	MCW	1514	1288	924	514	230	33	6	23	153	505	865	1370
IA	Ottumwa	OTM	1310	1110	724	395	159	15	2	9	103	396	699	1152
IA	Sioux City	SUX	1393	1177	792	424	166	17	2	8	112	435	807	1282
IA	Waterloo	ALO	1449	1225	841	468	192	19	3	14	128	458	802	1304
ID	Boise	BOI	985	785	611	430	220	54	0	6	62	356	722	993
ID	Burley	BYI	1119	945	747	559	339	124	5	24	170	496	817	1106
ID	Idaho Falls	IDA	1379	1179	885	610	385	159	11	36	220	585	934	1270
ID	Lewiston	LWS	867	718	593	416	211	57	1	4	58	376	699	937
ID	Pocatello	PIH	1229	1046	806	589	366	128	5	22	182	535	887	1196
IL	Chicago	ORD	1256	1078	773	451	208	30	2	6	79	371	678	1109
IL	Moline	MLI	1280	1095	716	375	147	13	1	5	82	369	675	1145
IL	Peoria	PIA	1221	1034	666	346	134	10	0	5	64	348	646	1086
IL	Quincy	UIN	1178	996	628	328	120	8	0	5	66	332	611	1041
IL	Rockford	RFD	1330	1137	794	437	192	22	4	9	96	403	724	1193
IL	Springfield	SPI	1155	972	606	308	111	9	0	5	61	323	586	1006
IN	Evansville	EVV	981	828	505	242	73	4	0	1	27	247	516	863
IN	Fort Wayne	FWA	1247	1086	751	414	174	18	1	7	86	388	669	1074
IN	Indianapolis	IND	1131	968	620	316	120	10	1	3	46	314	592	987
IN	South Bend	SBN	1253	1090	783	442	210	29	2	11	96	404	685	1079
IN	West Lafayette	LAF	1178	1006	653	350	145	14	0	5	63	345	612	1022
KS	Concordia	CNK	1117	938	595	329	121	7	0	2	57	306	641	1067
KS	Dodge City	DDC	979	847	555	317	110	5	0	2	45	276	609	978
KS	Garden City	GCK	1010	868	572	336	112	6	1	2	43	294	624	1007
KS	Goodland	GLD	1059	946	668	436	196	24	3	5	89	394	720	1078
KS	Russell	RSL	1074	911	582	328	116	7	0	2	50	297	638	1050
KS	Salina	SLN	1043	872	532	279	87	3	0	1	36	256	570	997
KS	Topeka	TOP	1079	892	545	271	86	3	0	2	46	274	574	972
KS	Wichita	ICT	985	810	487	240	69	2	0	0	24	227	528	924
KY	Bowling Green	BWG	877	727	438	220	59	3	0	1	21	215	467	779
KY	Jackson	JKL	924	774	479	230	88	7	1	2	37	242	464	802
KY	Lexington	LEX	993	842	547	278	99	6	0	2	42	278	540	874
KY	Louisville	SDF	932	780	473	210	58	3	0	0	19	213	462	809
KY	Paducah	PAH	933	779	484	240	71	5	0	2	35	253	515	842
LA	Baton Rouge	BTR	398	310	128	40	3	0	0	0	0	48	182	376
LA	Lafayette	LFT	380	289	116	29	1	0	0	0	0	40	149	349
LA	Lake Charles	LCH	383	299	121	32	1	0	0	0	0	33	153	348
LA	Monroe	MLU	548	439	208	63	7	0	0	0	1	80	257	501
LA	New Orleans	MSY	347	263	99	23	0	0	0	0	0	24	124	309
LA	Shreveport	SHV	521	418	193	58	7	0	0	0	0	69	236	490
MA	Boston	BOS	1111	947	792	467	230	56	3	5	55	315	574	905

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MA	Worcester	ORH	1273	1083	892	514	268	79	9	16	107	435	682	1057
MD	Baltimore	BWI	969	837	602	309	109	8	0	0	26	265	511	836
MD	Salisbury	SBY	929	806	599	328	141	14	1	1	29	254	481	775
ME	Augusta	AUG	1410	1181	992	594	317	101	12	23	148	484	769	1168
ME	Bangor	BGR	1475	1245	1039	633	333	106	14	30	177	510	808	1212
ME	Caribou	CAR	1680	1420	1228	766	423	153	36	79	268	628	944	1401
ME	Houlton	HUL	1630	1393	1184	756	438	172	48	84	272	620	907	1359
ME	Portland	PWM	1318	1116	950	598	332	103	11	19	138	463	727	1089
MI	Alpena	APN	1419	1264	1076	685	387	118	31	54	209	545	826	1219
MI	Detroit	DTW	1226	1077	812	445	192	22	2	5	77	378	665	1049
MI	Flint	FNT	1306	1148	884	513	252	47	11	19	130	452	733	1116
MI	Grand Rapids	GRR	1264	1118	853	488	229	34	5	11	108	434	713	1077
MI	Houghton Lake	HTL	1433	1280	1044	629	335	103	37	65	223	562	836	1225
MI	Jackson	JXN	1286	1126	842	483	238	45	9	17	131	451	713	1100
MI	Lansing	LAN	1303	1148	873	510	250	46	10	19	130	455	729	1110
MI	Marquette	MQT	1515	1339	1152	765	441	162	64	82	264	616	945	1356
MI	Muskegon	MKG	1215	1097	875	528	268	54	8	17	119	432	701	1043
MI	Saginaw	MBS	1323	1172	917	540	261	48	10	20	129	450	738	1129
MI	Sault St Marie	SSM	1526	1324	1144	715	404	152	51	61	217	571	869	1299
MI	Traverse City	TVC	1312	1186	980	630	342	90	21	26	155	486	763	1132
MN	Alexandria	AXN	1675	1443	1085	589	298	66	10	29	183	561	967	1497
MN	Duluth	DLH	1676	1419	1140	713	430	156	45	69	256	630	1004	1506
MN	Hibbing	HIB	1780	1506	1170	737	454	181	75	126	334	695	1073	1599
MN	Int'l Falls	INL	1853	1586	1229	734	443	167	69	125	328	695	1099	1660
MN	Minneapolis	MSP	1512	1267	921	466	203	25	2	8	116	460	842	1353
MN	Rochester	RST	1531	1308	944	512	236	38	8	25	147	489	851	1377
MN	Saint Cloud	STC	1625	1385	1036	565	288	56	10	29	184	553	949	1463
MO	Columbia	COU	1077	896	547	274	96	5	0	3	48	287	557	955
MO	Joplin	JLN	914	751	439	218	70	3	0	1	28	217	445	821
MO	Kansas City	MCI	1104	918	564	280	92	5	0	1	46	281	575	993
MO	Saint Louis	STL	1002	835	498	230	67	3	0	1	26	227	498	883
MO	Springfield	SGF	970	800	498	258	89	4	0	2	39	261	511	881
MS	Greenwood	GWO	628	506	255	98	17	0	0	0	5	123	282	565
MS	McComb	MCB	490	384	174	61	9	0	0	0	1	71	230	446
MS	Tupelo	TUP	692	555	294	124	23	0	0	0	6	134	343	621
MT	Billings	BIL	1148	1004	776	536	332	93	3	13	146	499	829	1170
MT	Butte	BTM	1349	1201	996	783	564	301	67	117	366	724	1096	1424
MT	Cut Bank	CTB	1288	1157	981	709	487	238	50	88	300	671	984	1319
MT	Great Falls	GTF	1189	1070	889	641	431	188	22	50	231	575	900	1211
MT	Havre	HVR	1435	1273	990	608	380	142	13	42	234	612	1003	1418
MT	Helena	HLN	1252	1035	837	594	370	140	7	30	188	566	935	1285
MT	Kalispell	FCA	1145	946	764	513	281	132	20	45	216	517	882	1158
MT	Lewistown	LWT	1254	1139	939	702	490	235	41	72	275	631	956	1279
MT	Miles City	MLS	1368	1191	866	519	312	82	2	12	155	535	918	1331
MT	Missoula	MSO	1201	979	807	598	384	168	15	33	205	600	960	1246
NC	Asheville	AVL	857	712	500	267	89	6	0	0	33	272	521	786
NC	Cape Hatteras	HAT	440	383	263	90	21	0	0	0	1	24	102	292
NC	Charlotte	CLT	734	598	373	172	40	0	0	0	9	169	412	658
NC	Greensboro	GSO	780	648	415	192	55	2	0	0	14	187	429	700

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC	Hickory	HKY	780	647	412	190	53	3	0	0	15	189	427	706
NC	New Bern	EWN	659	548	352	148	29	0	0	0	2	117	315	552
NC	Raleigh Durham	RDU	729	599	384	170	43	1	0	0	9	163	385	642
NC	Wilmington	ILM	617	510	324	128	24	0	0	0	1	103	297	517
ND	Bismarck	BIS	1595	1394	1044	589	328	80	8	28	198	594	1015	1472
ND	Devil's Lake	P11	1771	1580	1237	670	373	117	21	45	227	630	1091	1612
ND	Fargo	FAR	1718	1498	1119	575	288	56	12	31	185	557	992	1522
ND	Grand Forks	GFK	1803	1593	1226	639	355	83	22	46	223	618	1078	1609
ND	Minot	MOT	1606	1438	1119	609	360	101	17	37	204	624	1051	1512
ND	Williston	ISN	1635	1447	1089	620	381	119	13	36	226	654	1090	1553
NE	Grand Island	GRI	1231	1042	698	398	160	17	2	5	86	389	739	1172
NE	Lincoln	LNK	1261	1055	680	377	137	10	1	5	83	371	717	1169
NE	Norfolk	OFK	1313	1106	752	426	176	22	3	8	109	417	777	1223
NE	North Platte	LBF	1210	1048	752	487	234	37	3	10	135	477	821	1219
NE	Omaha	OMA	1292	1088	705	363	133	10	1	5	75	360	714	1179
NE	Scottsbluff	BFF	1138	1000	742	510	263	53	5	12	133	482	811	1190
NE	Valentine	VTN	1262	1117	816	510	260	51	4	12	143	496	848	1247
NH	Concord	CON	1380	1159	965	571	282	81	9	26	151	487	770	1150
NH	Lebanon	LEB	1439	1217	1000	598	285	81	9	28	152	511	794	1199
NJ	Atlantic City	ACY	975	847	663	366	151	20	0	1	31	263	512	817
NJ	Newark	EWR	1016	856	651	338	113	11	0	1	20	253	510	844
NM	Albuquerque	ABQ	821	668	469	236	58	1	0	0	15	199	536	859
NM	Carlsbad	CNM	617	470	255	86	21	0	0	0	4	94	349	638
NM	Clayton	CAO	853	788	564	343	126	11	2	5	52	278	558	888
NM	Gallup	GUP	1078	901	765	535	279	52	1	4	124	464	801	1090
NM	Roswell	ROW	701	545	314	123	27	0	0	0	7	127	418	740
NV	Elko	EKO	1221	990	795	593	349	109	2	16	156	516	863	1180
NV	Ely	ELY	1215	1032	864	663	434	151	6	33	218	569	884	1214
NV	Las Vegas	LAS	470	350	165	58	6	0	0	0	0	28	228	522
NV	Lovelock	LOL	987	771	617	431	183	35	0	4	71	373	741	1039
NV	Reno	RNO	886	727	585	431	190	43	0	3	47	303	637	912
NV	Tonopah	TPH	955	807	675	482	211	42	0	3	62	347	697	1011
NV	Winnemucca	WMC	1053	859	727	564	317	96	2	15	151	498	826	1097
NY	Albany	ALB	1303	1106	885	489	215	37	2	11	99	438	713	1092
NY	Binghamton	BGM	1328	1145	942	561	274	77	12	26	150	487	743	1133
NY	Buffalo	BUF	1242	1122	911	551	247	49	4	10	94	424	674	1041
NY	Glens Falls	GFL	1437	1236	996	581	282	74	12	34	177	518	789	1193
NY	Massena	MSS	1531	1318	1083	622	302	81	10	36	169	537	835	1287
NY	New York	LGA	976	834	657	338	118	12	0	1	11	206	456	786
NY	Rochester	ROC	1241	1106	888	537	254	54	6	15	107	427	692	1038
NY	Syracuse	SYR	1271	1125	908	523	232	46	3	12	99	417	690	1069
NY	Utica	UCA	1198	1011	784	386	142	32	2	11	57	307	599	991
NY	Watertown	ART	1434	1269	1007	607	308	89	14	35	157	486	757	1159
OH	Akron Canton	CAK	1208	1066	800	439	192	39	3	8	91	406	664	1036
OH	Cincinnati	CVG	1063	908	603	304	110	9	1	2	44	309	577	930
OH	Cleveland	CLE	1166	1030	795	451	197	32	2	5	71	365	619	994
OH	Columbus	CMH	1109	963	665	326	124	11	0	2	47	329	586	950
OH	Dayton	DAY	1171	1010	697	368	151	15	1	4	67	358	628	1013
OH	Findlay	FDY	1212	1055	755	412	166	19	1	5	81	371	639	1041

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
OH	Mansfield	MFD	1229	1079	799	447	203	42	6	11	100	415	664	1053
OH	Toledo	TOL	1231	1079	797	446	189	22	1	6	86	389	678	1067
OH	Youngstown	YNG	1215	1068	820	464	219	55	7	16	108	425	666	1037
OK	Hobart	HBR	769	642	367	174	41	0	0	0	6	149	401	753
OK	McAlester	MLC	731	588	308	140	33	0	0	0	9	135	335	673
OK	Oklahoma City	OKC	785	640	347	148	35	1	0	0	9	144	390	744
OK	Tulsa	TUL	809	663	363	155	37	1	0	0	11	151	388	751
OR	Astoria	AST	646	584	578	493	365	222	127	112	184	362	547	682
OR	Baker	BKE	1176	964	817	649	426	214	38	62	256	611	923	1191
OR	Eugene	EUG	723	629	558	455	305	147	22	23	100	358	595	763
OR	Medford	MFR	760	595	527	391	188	52	1	3	39	276	606	790
OR	Pendleton	PDT	910	745	606	454	248	85	5	8	88	399	715	972
OR	Portland	PDX	718	594	523	388	217	89	8	8	59	290	554	755
OR	Redmond	RDM	946	835	760	640	414	214	42	60	214	540	801	1029
OR	Salem	SLE	712	616	554	443	269	121	14	14	86	336	583	755
PA	Allentown	ABE	1134	974	739	413	168	23	1	4	61	362	623	966
PA	Altoona	AOO	1176	1037	788	440	203	42	5	12	108	413	659	1028
PA	Bradford	BFD	1367	1213	991	621	350	138	58	75	229	574	797	1176
PA	Du Bois	DUJ	1276	1125	867	509	255	78	16	27	141	473	714	1103
PA	Erie	ERI	1167	1068	869	529	252	47	5	8	78	372	619	976
PA	Harrisburg	CXY	1049	918	670	355	133	15	0	2	44	318	573	908
PA	Philadelphia	PHL	986	848	613	308	94	7	0	1	15	238	490	822
PA	Pittsburgh	PIT	1141	997	731	386	165	27	2	5	76	381	631	981
PA	Williamsport	IPT	1165	1011	766	414	175	26	1	6	71	380	649	1001
RI	Providence	PVD	1104	946	781	453	218	44	2	3	57	331	585	916
SC	Charleston	CHS	504	393	205	72	7	0	0	0	1	62	226	412
SC	Columbia	CAE	606	478	269	103	12	0	0	0	3	101	321	543
SC	Florence	FLO	624	498	285	113	18	0	0	0	3	106	301	524
SC	Greenville	GSP	688	567	344	145	32	1	0	0	6	147	375	632
SD	Aberdeen	ABR	1624	1399	1024	572	285	57	7	28	192	573	993	1471
SD	Huron	HON	1494	1288	919	516	245	45	5	15	147	505	909	1378
SD	Pierre	PIR	1384	1215	887	513	267	51	3	9	129	495	893	1316
SD	Rapid City	RAP	1228	1116	840	559	332	88	6	16	154	509	863	1228
SD	Sioux Falls	FSD	1479	1265	900	502	239	35	4	15	141	488	872	1356
TN	Bristol	TRI	903	748	497	258	82	4	0	1	28	266	531	820
TN	Chattanooga	CHA	737	589	338	141	30	0	0	0	6	144	393	668
TN	Crossville	CSV	898	742	482	252	89	6	1	2	37	256	489	793
TN	Jackson	MKL	797	660	373	173	41	1	0	1	17	186	418	712
TN	Knoxville	TYS	808	654	397	182	46	1	0	0	11	191	444	738
TN	Memphis	MEM	700	566	296	111	18	0	0	0	3	115	329	623
TN	Nashville	BNA	813	665	392	175	45	2	0	0	12	175	422	718
TX	Abilene	ABI	584	469	230	79	20	0	0	0	3	87	279	570
TX	Alice	ALI	242	176	58	9	0	0	0	0	0	9	64	224
TX	Amarillo	AMA	820	717	457	242	81	2	0	1	25	218	501	821
TX	Austin	AUS	470	356	165	46	3	0	0	0	0	44	192	436
TX	Brownsville	BRO	144	109	28	7	0	0	0	0	0	1	28	145
TX	College Station	CLL	417	316	127	33	2	0	0	0	0	32	145	375
TX	Corpus Christi	CRP	252	177	58	11	0	0	0	0	0	9	66	226
TX	Dallas-Ft. Worth	DFW	550	438	195	53	9	0	0	0	0	53	213	506

Station Location		Code	Monthly Heating Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
TX	Del Rio	DRT	384	253	80	16	1	0	0	0	0	18	135	380
TX	El Paso	ELP	560	416	216	62	7	0	0	0	1	52	303	584
TX	Galveston	GLS	291	224	73	12	0	0	0	0	0	7	62	233
TX	Houston	IAH	362	271	106	23	0	0	0	0	0	23	129	332
TX	Laredo	LRD	216	146	31	6	0	0	0	0	0	5	47	199
TX	Lubbock	LBB	710	584	337	150	45	0	0	0	10	143	405	718
TX	Lufkin	LFK	474	368	165	49	4	0	0	0	0	53	202	433
TX	McAllen	MFE	160	117	22	10	0	0	0	0	0	3	31	149
TX	Midland Odessa	MAF	622	480	254	83	19	0	0	0	4	87	329	614
TX	San Angelo	SJT	548	422	196	67	10	0	0	0	1	72	259	524
TX	San Antonio	SAT	374	275	105	24	2	0	0	0	1	28	135	354
TX	Victoria	VCT	337	243	90	21	1	0	0	0	0	22	116	306
TX	Waco	ACT	521	404	184	55	6	0	0	0	0	54	211	485
TX	Wichita Falls	SPS	665	540	267	95	23	0	0	0	2	94	306	641
UT	Cedar City	CDC	1100	910	731	535	268	58	0	3	103	436	771	1110
UT	Salt Lake City	SLC	1092	857	641	432	218	45	0	3	58	350	718	1055
VA	Lynchburg	LYH	904	773	526	269	101	7	0	2	34	271	523	822
VA	Norfolk	ORF	737	632	440	201	55	1	0	0	3	129	349	605
VA	Richmond	RIC	821	694	463	213	60	2	0	0	10	181	409	704
VA	Roanoke	ROA	846	719	478	229	78	4	0	0	27	224	474	765
VT	Burlington	BTV	1427	1226	1002	581	263	61	5	23	133	495	768	1188
VT	Montpelier	MPV	1501	1280	1065	652	335	114	24	52	200	568	842	1269
WA	Bellingham	BLI	767	672	628	492	341	187	78	78	209	442	647	792
WA	Olympia	OLM	772	686	636	510	342	186	67	68	180	433	658	817
WA	Quillayute	UIL	702	639	651	549	430	282	179	160	237	441	619	742
WA	Seattle Tacoma	SEA	706	611	586	451	285	142	34	29	122	368	597	745
WA	Spokane	GEG	1094	904	769	556	320	141	17	23	147	511	879	1144
WA	Walla Walla	ALW	869	701	532	383	195	51	1	3	51	335	662	930
WA	Yakima	YKM	1029	785	662	476	242	84	8	15	124	456	817	1102
WI	Eau Claire	EAU	1546	1309	977	533	258	49	7	26	169	524	878	1386
WI	Green Bay	GRB	1452	1253	979	576	289	60	12	23	165	494	813	1274
WI	Lacrosse	LSE	1452	1226	870	457	197	27	2	11	117	442	790	1303
WI	Madison	MSN	1404	1202	887	510	240	36	6	17	140	462	784	1247
WI	Milwaukee	MKE	1288	1111	858	550	289	64	7	9	100	397	713	1135
WI	Wausau	AUW	1547	1312	1019	585	294	67	13	31	192	549	892	1369
WV	Beckley	BKW	1050	897	647	355	171	36	9	9	87	368	607	938
WV	Charleston	CRW	942	810	537	257	100	7	0	1	36	273	519	838
WV	Elkins	EKN	1130	996	750	455	225	62	17	11	122	436	693	1005
WV	Huntington	HTS	956	811	533	253	95	6	0	1	39	280	528	846
WV	Martinsburg	MRB	1020	884	642	341	138	15	0	1	48	323	569	906
WV	Morgantown	MGW	1040	904	633	337	138	19	3	2	52	333	558	890
WV	Parkersburg	PKB	1040	891	605	302	124	14	0	2	50	329	567	904
WY	Casper	CPR	1191	1088	864	644	408	129	12	28	208	574	880	1244
WY	Cheyenne	CYS	1084	1037	826	630	390	120	14	30	201	556	837	1163
WY	Cody	COD	1171	1048	793	600	382	139	14	36	196	551	869	1209
WY	Lander	LND	1301	1128	842	605	380	121	7	22	171	563	923	1328
WY	Rock Springs	RKS	1320	1173	941	691	444	159	8	35	219	598	980	1336
WY	Sheridan	SHR	1220	1081	843	612	404	138	11	30	197	555	908	1272
WY	Worland	WRL	1416	1161	795	529	321	85	5	16	167	553	934	1415

Table 7C.3.3 Weather Station Monthly Cooling Degree Day Data (10-Year Average)

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AK	Anchorage	ANC	0	0	0	0	0	1	4	1	0	0	0	0
AK	Bethel	BET	0	0	0	0	0	2	3	2	0	0	0	0
AK	Cold Bay	CDB	0	0	0	0	0	0	0	0	0	0	0	0
AK	Cordova	CDV	0	0	0	0	0	0	0	0	0	0	0	0
AK	Homer	HOM	0	0	0	0	0	0	0	0	0	0	0	0
AK	Juneau	JNU	0	0	0	0	0	2	1	1	0	0	0	0
AK	Kenai	ENA	0	0	0	0	0	0	1	0	0	0	0	0
AK	Ketchikan	KTN	0	0	0	0	0	5	7	6	0	0	0	0
AK	King Salmon	AKN	0	0	0	0	0	0	1	2	0	0	0	0
AK	Kodiak	ADQ	0	0	0	0	0	0	3	1	0	0	0	0
AK	Sitka	SIT	0	0	0	0	0	1	0	3	0	0	0	0
AK	St Paul Island	SNP	0	0	0	0	0	0	0	0	0	0	0	0
AK	Talkeetna	TKA	0	0	0	0	0	5	12	5	0	0	0	0
AK	Valdez	VWS	0	0	0	0	3	3	6	4	0	0	0	0
AK	Yakutat	YAK	0	0	0	0	0	0	0	0	0	0	0	0
AL	Birmingham	BHM	1	3	34	81	234	427	515	513	312	89	15	2
AL	Huntsville	HSV	1	1	21	67	214	414	481	487	269	64	7	1
AL	Mobile	MOB	10	10	53	120	319	485	538	537	399	170	41	14
AL	Montgomery	MGM	2	6	40	90	272	480	553	556	374	126	23	5
AL	Muscle Shoals	MSL	1	2	22	74	225	398	496	500	259	62	9	2
AL	Tuscaloosa	TCL	2	5	33	83	270	459	535	536	324	94	18	3
AR	Fayetteville	FYV	1	0	10	35	119	293	428	430	152	31	3	1
AR	Fort Smith	FSM	1	0	26	69	221	443	586	577	294	82	10	1
AR	Little Rock	LIT	2	2	27	69	231	454	560	564	299	82	11	1
AR	Texarkana	TXK	4	3	41	97	275	470	579	590	326	113	28	4
AZ	Douglas	DUG	0	2	7	33	197	441	516	453	303	90	2	0
AZ	Flagstaff	FLG	0	0	0	0	0	20	96	42	2	0	0	0
AZ	Phoenix	PHX	4	9	111	251	551	813	974	921	745	410	92	1
AZ	Tucson	TUS	1	3	47	136	384	642	728	672	530	250	47	0
AZ	Winslow	INW	0	0	2	4	87	271	467	378	153	14	1	0
AZ	Yuma	NYL	22	17	131	242	511	737	946	930	744	406	98	6
CA	Bakersfield	BFL	0	0	18	54	209	398	635	572	402	117	6	0
CA	Blythe	BLH	3	4	95	206	512	725	956	922	690	330	58	1
CA	Eureka	EKA	0	0	0	0	1	0	0	2	1	2	0	0
CA	Fresno	FAT	0	0	8	42	194	378	612	549	384	106	4	0
CA	Los Angeles	LAX	12	5	12	19	24	43	143	155	130	77	29	2
CA	Mt Shasta	MHS	0	0	0	0	14	37	158	113	35	2	0	0
CA	Paso Robles	PRB	0	0	2	12	65	156	308	282	184	41	2	0
CA	Red Bluff	RBL	0	0	6	27	146	359	553	479	323	80	6	0
CA	Redding	RDD	0	0	7	26	145	356	575	488	313	72	4	0
CA	Sacramento	SAC	0	0	1	18	87	217	354	315	224	46	0	0
CA	San Diego	SAN	5	1	9	17	30	58	174	214	177	82	20	1
CA	San Francisco	SFO	0	0	2	6	11	22	24	35	57	26	2	0
CA	Stockton	SCK	0	0	3	23	108	243	399	360	246	54	1	0
CO	Alamosa	ALS	0	0	0	0	0	12	68	28	1	0	0	0
CO	Colorado Spring	COS	0	0	0	0	18	118	251	171	41	2	0	0

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CO	Denver	DEN	0	0	0	2	32	145	337	264	74	8	0	0
CO	Eagle	EGE	0	0	0	0	2	30	132	72	3	1	0	0
CO	Pueblo	PUB	0	0	1	4	45	212	392	303	80	7	0	0
CO	Trinidad	TAD	0	0	0	3	37	181	335	265	87	8	0	0
CT	Bridgeport	BDR	0	0	0	1	27	158	326	297	120	12	0	0
CT	Hartford	BDL	0	0	0	7	41	153	300	252	87	8	0	0
DC	Washington	DCA	0	0	3	28	126	332	490	450	227	39	2	0
DE	Wilmington	ILG	0	0	0	13	78	241	391	344	150	20	0	0
FL	Daytona Beach	DAB	28	40	91	163	349	467	531	547	468	306	109	55
FL	Fort Myers	FMY	76	107	194	277	460	532	577	587	530	404	201	122
FL	Ft Lauderdale	FLL	147	174	264	334	472	546	594	608	547	468	293	212
FL	Gainesville	GNV	15	22	67	135	332	464	520	528	423	227	57	23
FL	Jacksonville	JAX	11	14	53	118	306	457	529	537	409	205	46	20
FL	Key West	EYW	161	184	282	349	491	557	619	640	569	499	326	220
FL	Melbourne	MLB	52	70	145	208	389	483	532	552	489	352	160	97
FL	Miami	MIA	144	179	270	340	485	548	602	607	550	468	287	208
FL	Orlando	MCO	37	60	135	215	403	499	562	571	496	332	130	68
FL	Pensacola	PNS	10	10	53	123	338	511	557	552	438	201	46	14
FL	Tallahassee	TLH	6	8	51	112	330	495	552	554	426	196	36	12
FL	Tampa	TPA	45	59	154	243	440	529	573	584	523	368	153	82
FL	Vero Beach	VRB	55	76	145	205	377	475	530	549	484	364	177	109
FL	West Palm Beach	PBI	106	136	223	292	447	523	577	589	524	429	243	166
GA	Albany	ABY	7	5	46	114	335	508	571	561	403	159	30	10
GA	Athens	AHN	0	0	17	50	190	397	488	480	270	57	7	1
GA	Atlanta	ATL	0	0	21	56	205	403	480	484	286	72	9	1
GA	Augusta	AGS	2	2	20	62	228	426	520	514	318	84	9	2
GA	Brunswick	SSI	6	10	47	122	310	474	564	561	413	199	69	28
GA	Columbus	CSG	1	3	33	89	285	476	552	550	367	121	22	4
GA	Macon	MCN	1	1	22	68	252	454	538	530	331	97	17	2
GA	Savannah	SAV	5	6	34	103	283	463	547	542	379	148	27	10
GA	Waycross	AYS	8	10	54	131	330	479	550	546	400	173	41	15
HI	Hilo-Hawaii	ITO	219	192	230	229	298	321	359	367	346	338	278	245
HI	Honolulu-Oahu	HNL	279	261	315	355	427	477	518	533	496	477	387	323
HI	Kahului-Maui	OGG	234	201	255	280	349	396	443	463	426	414	327	272
HI	Lihue-Kauai	LIH	245	203	252	286	363	406	450	467	439	425	330	277
IA	Burlington	BRL	0	0	5	23	96	251	366	309	122	25	0	0
IA	Cedar Rapids	CID	0	0	4	12	55	169	269	204	67	15	0	0
IA	Des Moines	DSM	0	0	5	17	80	245	393	318	113	23	0	0
IA	Dubuque	DBQ	0	0	2	5	41	144	243	183	59	12	0	0
IA	Mason City	MCW	0	0	1	5	36	136	241	165	48	11	0	0
IA	Ottumwa	OTM	0	0	4	17	67	199	322	259	81	18	0	0
IA	Sioux City	SUX	0	0	3	13	72	205	345	256	82	17	0	0
IA	Waterloo	ALO	0	0	3	7	52	172	286	206	71	16	0	0
ID	Boise	BOI	0	0	0	4	45	145	444	359	127	13	0	0
ID	Burley	BYI	0	0	0	0	11	48	211	150	16	3	0	0
ID	Idaho Falls	IDA	0	0	0	0	7	27	151	106	6	1	0	0
ID	Lewiston	LWS	0	0	0	1	31	106	374	324	99	5	0	0
ID	Pocatello	PIH	0	0	0	0	9	46	222	163	16	1	0	0
IL	Chicago	ORD	0	0	5	8	53	186	321	265	95	16	0	0

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
IL	Moline	MLI	0	0	4	13	77	224	349	280	99	19	0	0
IL	Peoria	PIA	0	0	5	15	84	236	363	301	120	22	0	0
IL	Quincy	UIN	0	0	5	24	95	250	378	329	116	23	0	0
IL	Rockford	RFD	0	0	5	5	52	178	291	228	84	16	0	0
IL	Springfield	SPI	0	0	7	24	111	255	363	317	129	27	0	0
IN	Evansville	EVV	0	0	9	32	134	321	422	401	176	33	1	0
IN	Fort Wayne	FWA	0	0	3	9	64	194	294	218	78	12	0	0
IN	Indianapolis	IND	0	0	7	18	92	252	362	331	141	24	0	0
IN	South Bend	SBN	0	0	5	9	56	176	279	215	81	14	0	0
IN	West Lafayette	LAF	0	0	8	19	84	220	320	275	112	21	1	0
KS	Concordia	CNK	0	0	5	17	97	300	464	380	139	26	0	0
KS	Dodge City	DDC	0	0	3	20	117	328	500	424	166	35	0	0
KS	Garden City	GCK	0	0	4	19	110	303	468	399	157	28	0	0
KS	Goodland	GLD	0	0	1	4	53	201	392	299	91	12	0	0
KS	Russell	RSL	0	0	4	19	114	322	509	412	155	29	0	0
KS	Salina	SLN	0	0	8	29	143	374	551	473	181	38	1	0
KS	Topeka	TOP	0	0	11	32	132	333	488	429	148	36	2	0
KS	Wichita	ICT	0	0	8	34	151	376	544	485	208	43	2	0
KY	Bowling Green	BWG	0	0	13	45	148	329	437	431	195	34	3	1
KY	Jackson	JKL	0	0	13	49	107	237	323	330	154	33	4	0
KY	Lexington	LEX	0	0	7	22	101	252	357	342	150	25	0	0
KY	Louisville	SDF	0	0	15	46	157	349	458	448	221	46	3	1
KY	Paducah	PAH	0	0	9	34	134	308	403	371	160	30	3	0
LA	Baton Rouge	BTR	18	20	75	152	354	516	568	578	419	186	46	19
LA	Lafayette	LFT	18	20	83	181	381	530	574	596	437	212	66	22
LA	Lake Charles	LCH	14	17	71	158	365	528	570	591	439	214	61	19
LA	Monroe	MLU	6	10	49	112	305	497	570	590	377	135	29	7
LA	New Orleans	MSY	21	23	85	183	395	541	577	595	476	244	68	26
LA	Shreveport	SHV	7	11	53	116	315	510	596	625	407	151	36	6
MA	Boston	BOS	0	0	1	5	31	136	296	258	91	10	0	0
MA	Worcester	ORH	0	0	0	4	29	97	216	180	50	6	0	0
MD	Baltimore	BWI	0	0	1	20	97	270	418	361	154	22	1	0
MD	Salisbury	SBY	0	0	2	22	89	235	397	338	157	31	2	0
ME	Augusta	AUG	0	0	0	0	11	64	174	135	28	3	0	0
ME	Bangor	BGR	0	0	0	0	7	51	156	115	24	1	0	0
ME	Caribou	CAR	0	0	0	0	4	36	87	60	9	1	0	0
ME	Houlton	HUL	0	0	0	0	5	35	87	68	14	1	0	0
ME	Portland	PWM	0	0	0	1	8	56	166	134	32	1	0	0
MI	Alpena	APN	0	0	1	0	15	63	132	98	25	6	0	0
MI	Detroit	DTW	0	0	2	6	49	180	300	250	88	11	0	0
MI	Flint	FNT	0	0	2	4	38	129	220	170	55	9	0	0
MI	Grand Rapids	GRR	0	0	3	6	43	150	261	204	68	10	0	0
MI	Houghton Lake	HTL	0	0	1	0	21	70	133	94	24	5	0	0
MI	Jackson	JXN	0	0	2	5	39	126	215	165	56	9	0	0
MI	Lansing	LAN	0	0	2	4	37	131	233	177	59	9	0	0
MI	Marquette	MQT	0	0	0	0	11	48	110	73	25	3	0	0
MI	Muskegon	MKG	0	0	3	2	30	114	218	182	60	8	0	0
MI	Saginaw	MBS	0	0	2	2	38	133	218	161	52	11	0	0
MI	Sault St Marie	SSM	0	0	0	0	10	32	95	73	20	3	0	0

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MI	Traverse City	TVC	0	0	3	2	25	94	188	149	51	11	0	0
MN	Alexandria	AXN	0	0	0	2	22	84	231	148	46	6	0	0
MN	Duluth	DLH	0	0	0	0	5	30	127	77	22	1	0	0
MN	Hibbing	HIB	0	0	0	0	8	20	77	48	12	1	0	0
MN	Int'l Falls	INL	0	0	0	0	6	27	79	51	15	2	0	0
MN	Minneapolis	MSP	0	0	2	5	46	177	347	241	88	17	0	0
MN	Rochester	RST	0	0	2	3	36	132	225	146	54	15	0	0
MN	Saint Cloud	STC	0	0	1	2	27	101	228	140	47	7	0	0
MO	Columbia	COU	0	0	9	30	109	281	421	381	135	28	1	0
MO	Joplin	JLN	1	0	21	59	155	357	506	490	194	53	8	0
MO	Kansas City	MCI	0	0	9	32	117	298	452	415	143	33	2	0
MO	Saint Louis	STL	0	0	16	48	158	367	505	459	194	45	3	1
MO	Springfield	SGF	0	0	10	30	119	309	451	429	160	32	2	0
MS	Greenwood	GWO	5	5	39	94	265	443	515	528	307	103	27	6
MS	McComb	MCB	8	10	50	106	287	467	540	539	379	146	29	11
MS	Tupelo	TUP	1	2	26	76	234	427	524	525	288	78	11	1
MT	Billings	BIL	0	0	0	2	17	84	326	239	58	7	0	0
MT	Butte	BTM	0	0	0	0	1	8	62	31	1	0	0	0
MT	Cut Bank	CTB	0	0	0	0	3	12	101	66	12	0	0	0
MT	Great Falls	GTF	0	0	1	0	5	27	191	133	33	1	0	0
MT	Havre	HVR	0	0	0	0	13	37	220	145	24	1	0	0
MT	Helena	HLN	0	0	0	0	11	50	250	165	32	0	0	0
MT	Kalispell	FCA	0	0	0	8	32	92	280	258	74	12	0	0
MT	Lewistown	LWT	0	0	0	0	2	18	137	95	19	1	0	0
MT	Miles City	MLS	0	0	0	2	19	105	365	269	68	7	0	0
MT	Missoula	MSO	0	0	0	0	5	37	204	137	16	0	0	0
NC	Asheville	AVL	0	0	0	7	61	197	283	276	94	9	1	0
NC	Cape Hatteras	HAT	21	20	71	152	297	512	608	614	491	280	85	39
NC	Charlotte	CLT	0	0	12	37	155	342	441	432	230	42	5	1
NC	Greensboro	GSO	0	0	10	38	143	329	434	424	204	36	4	0
NC	Hickory	HKY	0	0	8	34	130	315	400	394	185	30	3	0
NC	New Bern	EWN	1	2	15	60	177	375	481	467	276	84	12	5
NC	Raleigh Durham	RDU	1	1	14	52	172	374	489	462	245	54	8	1
NC	Wilmington	ILM	2	3	16	62	191	384	487	458	282	94	14	4
ND	Bismarck	BIS	0	0	0	1	12	77	248	170	44	3	0	0
ND	Devil's Lake	P11	0	0	0	0	7	61	179	120	32	5	0	0
ND	Fargo	FAR	0	0	1	2	25	108	233	151	55	10	0	0
ND	Grand Forks	GFK	0	0	0	1	11	67	180	117	36	3	0	0
ND	Minot	MOT	0	0	0	1	6	62	200	144	38	2	0	0
ND	Williston	ISN	0	0	0	0	8	50	225	158	31	2	0	0
NE	Grand Island	GRI	0	0	2	13	75	223	389	306	98	17	0	0
NE	Lincoln	LNK	0	0	4	18	86	253	428	343	107	23	1	0
NE	Norfolk	OFK	0	0	2	16	68	199	366	279	88	19	0	0
NE	North Platte	LBF	0	0	1	3	38	156	353	257	73	9	0	0
NE	Omaha	OMA	0	0	5	19	87	252	424	337	115	24	1	0
NE	Scottsbluff	BFF	0	0	0	1	28	144	348	253	59	2	0	0
NE	Valentine	VTN	0	0	1	3	34	142	365	273	79	7	0	0
NH	Concord	CON	0	0	0	3	20	91	196	158	39	2	0	0
NH	Lebanon	LEB	0	0	0	2	22	87	174	145	36	3	0	0

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NJ	Atlantic City	ACY	0	0	0	14	66	222	387	338	146	23	1	0
NJ	Newark	EWR	0	0	1	17	73	252	423	374	165	20	0	0
NM	Albuquerque	ABQ	0	0	0	8	118	354	471	393	179	18	0	0
NM	Carlsbad	CNM	0	3	22	93	283	509	522	515	278	78	5	0
NM	Clayton	CAO	0	0	1	9	75	240	378	318	121	20	1	0
NM	Gallup	GUP	0	0	0	0	5	71	221	148	23	0	0	0
NM	Roswell	ROW	0	0	7	55	217	461	508	475	247	53	2	0
NV	Elko	EKO	0	0	0	0	9	58	261	178	22	2	0	0
NV	Ely	ELY	0	0	0	0	3	25	151	95	7	0	0	0
NV	Las Vegas	LAS	0	0	39	121	419	685	910	830	572	202	17	0
NV	Lovelock	LOL	0	0	0	3	54	177	437	319	89	6	0	0
NV	Reno	RNO	0	0	0	3	47	172	421	328	123	6	0	0
NV	Tonopah	TPH	0	0	0	1	35	160	360	281	101	9	0	0
NV	Winnemucca	WMC	0	0	0	0	18	82	301	191	31	1	0	0
NY	Albany	ALB	0	0	0	6	36	134	251	203	58	4	0	0
NY	Binghamton	BGM	0	0	0	5	28	88	166	129	38	3	0	0
NY	Buffalo	BUF	0	0	1	2	34	117	224	188	62	7	0	0
NY	Glens Falls	GFL	0	0	0	1	21	82	160	131	29	1	0	0
NY	Massena	MSS	0	0	0	2	16	86	188	135	36	1	0	0
NY	New York	LGA	0	0	0	10	68	254	435	396	195	30	1	0
NY	Rochester	ROC	0	0	1	5	34	120	219	175	55	7	0	0
NY	Syracuse	SYR	0	0	0	6	39	129	241	196	61	4	0	0
NY	Utica	UCA	1	0	5	30	147	292	410	354	163	32	0	0
NY	Watertown	ART	0	0	0	2	23	82	162	157	46	4	0	0
OH	Akron Canton	CAK	0	0	2	6	53	145	247	208	69	9	0	0
OH	Cincinnati	CVG	0	0	7	18	89	233	348	341	143	22	0	0
OH	Cleveland	CLE	0	0	3	12	57	172	282	234	82	12	0	0
OH	Columbus	CMH	0	0	4	13	89	224	339	308	123	20	0	0
OH	Dayton	DAY	0	0	4	12	75	198	302	264	98	16	0	0
OH	Findlay	FDY	0	0	3	10	71	197	293	233	87	15	0	0
OH	Mansfield	MFD	0	0	2	8	56	142	230	199	65	10	0	0
OH	Toledo	TOL	0	0	2	8	52	179	286	226	78	11	0	0
OH	Youngstown	YNG	0	0	1	8	41	113	205	167	52	7	0	0
OK	Hobart	HBR	0	1	22	59	229	476	611	598	305	80	7	0
OK	McAlester	MLC	2	4	34	76	203	419	567	564	285	86	17	3
OK	Oklahoma City	OKC	0	1	22	60	205	427	580	562	272	70	9	1
OK	Tulsa	TUL	1	2	27	70	211	433	603	572	263	72	10	1
OR	Astoria	AST	0	0	0	0	3	3	8	6	6	0	0	0
OR	Baker	BKE	0	0	0	0	5	15	107	69	6	0	0	0
OR	Eugene	EUG	0	0	0	0	4	18	115	107	33	1	0	0
OR	Medford	MFR	0	0	0	4	36	104	342	305	135	6	0	0
OR	Pendleton	PDT	0	0	0	1	22	70	278	233	57	4	0	0
OR	Portland	PDX	0	0	0	1	19	51	172	168	67	2	0	0
OR	Redmond	RDM	0	0	0	0	7	22	127	86	16	0	0	0
OR	Salem	SLE	0	0	0	0	12	33	144	132	46	1	0	0
PA	Allentown	ABE	0	0	0	8	57	176	308	253	86	9	0	0
PA	Altoona	AOO	0	0	1	7	45	127	213	172	51	7	0	0
PA	Bradford	BFD	0	0	0	1	13	42	79	58	17	1	0	0
PA	Du Bois	DUJ	0	0	0	4	32	78	147	126	35	5	0	0

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PA	Erie	ERI	0	0	1	8	39	130	235	202	74	14	0	0
PA	Harrisburg	CXY	0	0	0	11	76	222	350	301	115	13	0	0
PA	Philadelphia	PHL	0	0	1	18	96	278	445	394	187	26	0	0
PA	Pittsburgh	PIT	0	0	1	9	59	151	263	231	76	9	0	0
PA	Williamsport	IPT	0	0	0	7	55	167	283	226	74	7	0	0
RI	Providence	PVD	0	0	0	3	27	137	301	266	88	10	0	0
SC	Charleston	CHS	3	4	30	97	268	454	542	529	360	134	26	7
SC	Columbia	CAE	1	2	27	83	252	448	540	527	329	86	12	2
SC	Florence	FLO	2	2	23	75	225	419	513	500	311	88	14	5
SC	Greenville	GSP	0	0	15	43	170	372	461	448	246	48	6	1
SD	Aberdeen	ABR	0	0	1	1	20	106	257	162	47	6	0	0
SD	Huron	HON	0	0	2	5	30	137	329	228	71	8	0	0
SD	Pierre	PIR	0	0	1	3	26	132	369	281	84	9	0	0
SD	Rapid City	RAP	0	0	0	1	15	94	320	240	61	6	0	0
SD	Sioux Falls	FSD	0	0	2	8	36	138	306	210	70	11	0	0
TN	Bristol	TRI	0	0	1	12	83	229	321	323	131	14	1	0
TN	Chattanooga	CHA	0	0	16	50	184	391	479	496	261	53	4	0
TN	Crossville	CSV	0	0	4	25	93	218	316	316	127	16	1	0
TN	Jackson	MKL	1	1	21	64	191	361	458	457	221	47	6	1
TN	Knoxville	TYS	0	0	10	41	152	336	426	427	211	36	3	0
TN	Memphis	MEM	1	2	35	86	266	481	562	569	334	100	12	1
TN	Nashville	BNA	0	1	16	56	170	370	477	475	243	48	5	0
TX	Abilene	ABI	2	9	45	128	289	487	581	583	327	121	27	3
TX	Alice	ALI	42	72	174	303	495	599	647	685	520	332	149	67
TX	Amarillo	AMA	0	0	7	24	134	338	440	403	173	34	1	0
TX	Austin	AUS	10	18	68	159	363	534	588	632	424	193	64	13
TX	Brownsville	BRO	73	101	213	348	510	596	629	664	532	382	200	88
TX	College Station	CLL	14	22	85	186	390	562	627	671	475	235	76	20
TX	Corpus Christi	CRP	36	60	156	283	448	549	601	653	510	335	139	56
TX	Dallas-Ft. Worth	DFW	6	11	53	127	338	561	680	702	429	173	45	7
TX	Del Rio	DRT	3	23	118	251	446	617	653	682	477	252	60	5
TX	El Paso	ELP	0	1	24	111	336	569	593	549	339	117	4	0
TX	Galveston	GLS	10	14	91	223	420	573	619	665	540	372	152	36
TX	Houston	IAH	17	27	92	193	408	565	609	649	472	251	80	27
TX	Laredo	LRD	48	90	260	431	625	744	743	800	598	416	187	57
TX	Lubbock	LBB	0	0	16	67	227	436	495	473	224	62	5	0
TX	Lufkin	LFK	12	16	63	144	341	513	584	620	412	178	53	14
TX	McAllen	MFE	75	117	257	394	561	657	691	728	582	423	214	90
TX	Midland Odessa	MAF	0	2	32	121	309	527	544	535	300	104	9	1
TX	San Angelo	SJT	2	9	51	150	338	540	585	593	347	130	26	3
TX	San Antonio	SAT	10	28	90	205	409	568	617	665	463	245	79	16
TX	Victoria	VCT	17	36	105	211	412	552	597	642	475	263	92	31
TX	Waco	ACT	6	11	55	141	337	549	653	678	420	177	50	9
TX	Wichita Falls	SPS	1	5	39	107	284	514	650	649	348	117	19	2
UT	Cedar City	CDC	0	0	0	0	12	111	306	224	42	2	0	0
UT	Salt Lake City	SLC	0	0	0	5	55	204	507	411	136	13	0	0
VA	Lynchburg	LYH	0	0	3	21	84	225	349	333	124	16	1	0
VA	Norfolk	ORF	1	1	10	49	146	348	486	452	262	68	7	1
VA	Richmond	RIC	0	1	7	43	145	342	475	439	222	47	3	0

Station Location		Code	Monthly Cooling Degree Days											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
VA	Roanoke	ROA	0	0	8	30	110	271	385	371	152	26	2	0
VT	Burlington	BTV	0	0	1	4	24	108	208	166	47	2	0	0
VT	Montpelier	MPV	0	0	0	1	12	58	115	96	21	1	0	0
WA	Bellingham	BLI	0	0	0	0	1	4	27	21	2	0	0	0
WA	Olympia	OLM	0	0	0	0	2	12	56	44	7	0	0	0
WA	Quillayute	UIL	0	0	0	0	2	4	11	11	3	0	0	0
WA	Seattle Tacoma	SEA	0	0	0	0	6	26	89	76	23	0	0	0
WA	Spokane	GEG	0	0	0	0	14	49	231	186	44	1	0	0
WA	Walla Walla	ALW	0	0	0	1	38	112	374	331	104	7	0	0
WA	Yakima	YKM	0	0	0	0	23	80	256	198	42	1	0	0
WI	Eau Claire	EAU	0	0	2	2	30	117	241	165	57	10	0	0
WI	Green Bay	GRB	0	0	1	1	24	105	201	140	46	8	0	0
WI	Lacrosse	LSE	0	0	3	8	46	174	309	227	80	15	0	0
WI	Madison	MSN	0	0	3	2	36	139	250	186	63	10	0	0
WI	Milwaukee	MKE	0	0	2	4	26	129	260	227	79	11	0	0
WI	Wausau	AUW	0	0	1	1	23	95	200	138	41	6	0	0
WV	Beckley	BKW	0	0	2	13	42	111	193	187	61	6	1	0
WV	Charleston	CRW	0	0	9	29	95	229	332	326	137	19	1	0
WV	Elkins	EKN	0	0	0	1	24	81	154	156	39	4	0	0
WV	Huntington	HTS	0	0	11	29	95	237	340	334	140	20	2	0
WV	Martinsburg	MRB	0	0	1	13	70	205	336	295	107	13	0	0
WV	Morgantown	MGW	0	0	4	18	75	169	282	264	102	17	1	0
WV	Parkersburg	PKB	0	0	5	19	79	190	302	291	113	17	0	0
WY	Casper	CPR	0	0	0	0	6	54	238	162	25	1	0	0
WY	Cheyenne	CYS	0	0	0	0	5	54	204	141	22	1	0	0
WY	Cody	COD	0	0	0	1	12	59	240	167	34	4	0	0
WY	Lander	LND	0	0	0	0	9	71	270	194	30	1	0	0
WY	Rock Springs	RKS	0	0	0	0	3	43	196	123	8	0	0	0
WY	Sheridan	SHR	0	0	0	0	4	49	239	181	30	2	0	0
WY	Worland	WRL	0	0	1	3	15	94	305	220	37	7	0	0

Table 7C.3.4 Weather Station Monthly Heating Degree Day Data Fractions (10-Year Average)

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AK	Anchorage	ANC	15%	12%	12%	8%	5%	3%	2%	2%	5%	8%	13%	14%
AK	Bethel	BET	15%	12%	13%	9%	5%	3%	2%	3%	4%	8%	12%	13%
AK	Cold Bay	CDB	12%	10%	12%	10%	8%	6%	5%	4%	5%	8%	10%	11%
AK	Cordova	CDV	13%	11%	12%	9%	6%	4%	3%	4%	5%	8%	12%	12%
AK	Homer	HOM	14%	11%	12%	9%	6%	5%	3%	3%	5%	8%	12%	12%
AK	Juneau	JNU	14%	12%	12%	9%	6%	4%	3%	3%	5%	8%	12%	13%
AK	Kenai	ENA	15%	12%	12%	8%	5%	3%	2%	3%	5%	8%	12%	14%
AK	Ketchikan	KTN	13%	12%	12%	9%	7%	4%	3%	3%	5%	8%	11%	13%
AK	King Salmon	AKN	15%	11%	13%	8%	6%	4%	3%	3%	5%	8%	12%	13%
AK	Kodiak	ADQ	12%	11%	12%	9%	7%	5%	4%	3%	5%	8%	11%	12%
AK	Sitka	SIT	13%	11%	12%	9%	7%	5%	4%	3%	5%	8%	11%	12%
AK	St Paul Island	SNP	12%	10%	12%	10%	8%	6%	5%	4%	5%	7%	9%	10%
AK	Talkeetna	TKA	16%	12%	12%	8%	5%	2%	1%	2%	5%	9%	13%	15%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AK	Valdez	VWS	16%	12%	13%	8%	5%	3%	2%	2%	4%	8%	13%	14%
AK	Yakutat	YAK	13%	11%	12%	9%	7%	5%	3%	4%	5%	8%	11%	12%
AL	Birmingham	BHM	25%	20%	10%	4%	1%	0%	0%	0%	0%	5%	12%	22%
AL	Huntsville	HSV	24%	20%	11%	5%	1%	0%	0%	0%	0%	5%	13%	22%
AL	Mobile	MOB	27%	21%	9%	3%	0%	0%	0%	0%	0%	3%	13%	24%
AL	Montgomery	MGM	26%	20%	10%	3%	0%	0%	0%	0%	0%	4%	13%	23%
AL	Muscle Shoals	MSL	24%	20%	11%	5%	1%	0%	0%	0%	0%	5%	12%	22%
AL	Tuscaloosa	TCL	25%	20%	10%	4%	1%	0%	0%	0%	0%	5%	13%	23%
AR	Fayetteville	FYV	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	21%
AR	Fort Smith	FSM	25%	20%	11%	4%	1%	0%	0%	0%	0%	4%	12%	23%
AR	Little Rock	LIT	25%	20%	11%	4%	1%	0%	0%	0%	0%	4%	12%	23%
AR	Texarkana	TXK	26%	21%	10%	4%	1%	0%	0%	0%	0%	4%	12%	24%
AZ	Douglas	DUG	24%	18%	13%	5%	1%	0%	0%	0%	0%	3%	13%	24%
AZ	Flagstaff	FLG	16%	14%	12%	10%	6%	2%	0%	1%	3%	8%	12%	16%
AZ	Phoenix	PHX	28%	21%	8%	1%	0%	0%	0%	0%	0%	1%	8%	34%
AZ	Tucson	TUS	25%	21%	11%	3%	0%	0%	0%	0%	0%	1%	10%	28%
AZ	Winslow	INW	21%	16%	12%	7%	2%	0%	0%	0%	0%	6%	13%	21%
AZ	Yuma	NYL	24%	21%	7%	2%	0%	0%	0%	0%	0%	0%	9%	37%
CA	Bakersfield	BFL	24%	16%	11%	7%	1%	0%	0%	0%	0%	3%	14%	25%
CA	Blythe	BLH	27%	19%	7%	1%	0%	0%	0%	0%	0%	1%	11%	34%
CA	Eureka	EKA	11%	10%	10%	10%	8%	6%	5%	5%	6%	7%	9%	11%
CA	Fresno	FAT	24%	17%	11%	7%	1%	0%	0%	0%	0%	2%	13%	24%
CA	Los Angeles	LAX	17%	17%	16%	12%	5%	1%	0%	0%	0%	3%	10%	20%
CA	Mt Shasta	MHS	16%	14%	13%	10%	6%	2%	0%	0%	2%	7%	13%	16%
CA	Paso Robles	PRB	19%	16%	13%	10%	3%	1%	0%	0%	1%	5%	13%	20%
CA	Red Bluff	RBL	21%	16%	13%	9%	2%	0%	0%	0%	0%	3%	14%	22%
CA	Redding	RDD	20%	16%	13%	9%	2%	0%	0%	0%	0%	4%	14%	22%
CA	Sacramento	SAC	22%	16%	12%	8%	2%	0%	0%	0%	0%	3%	14%	22%
CA	San Diego	SAN	19%	18%	14%	10%	4%	1%	0%	0%	0%	1%	10%	22%
CA	San Francisco	SFO	17%	13%	12%	10%	7%	4%	2%	2%	2%	4%	10%	16%
CA	Stockton	SCK	23%	16%	12%	8%	2%	0%	0%	0%	0%	3%	13%	22%
CO	Alamosa	ALS	17%	15%	11%	8%	5%	2%	0%	1%	3%	8%	12%	18%
CO	Colorado Spring	COS	17%	16%	12%	9%	4%	1%	0%	0%	2%	7%	12%	18%
CO	Denver	DEN	18%	16%	12%	8%	4%	1%	0%	0%	2%	7%	13%	19%
CO	Eagle	EGE	18%	15%	12%	8%	5%	2%	0%	0%	3%	8%	12%	18%
CO	Pueblo	PUB	19%	17%	12%	7%	3%	0%	0%	0%	1%	7%	13%	20%
CO	Trinidad	TAD	19%	17%	12%	8%	3%	1%	0%	0%	2%	7%	13%	19%
CT	Bridgeport	BDR	21%	18%	15%	8%	4%	1%	0%	0%	1%	5%	11%	17%
CT	Hartford	BDL	21%	17%	14%	8%	3%	1%	0%	0%	1%	6%	11%	17%
DC	Washington	DCA	23%	19%	13%	6%	2%	0%	0%	0%	0%	5%	11%	20%
DE	Wilmington	ILG	21%	19%	14%	7%	3%	0%	0%	0%	1%	6%	11%	18%
FL	Daytona Beach	DAB	32%	23%	10%	3%	0%	0%	0%	0%	0%	2%	8%	23%
FL	Fort Myers	FMY	39%	21%	8%	1%	0%	0%	0%	0%	0%	1%	5%	25%
FL	Ft Lauderdale	FLL	41%	23%	7%	1%	0%	0%	0%	0%	0%	0%	3%	25%
FL	Gainesville	GNV	29%	21%	10%	3%	0%	0%	0%	0%	0%	2%	10%	24%
FL	Jacksonville	JAX	28%	21%	10%	4%	0%	0%	0%	0%	0%	2%	11%	23%
FL	Key West	EYW	49%	22%	6%	0%	0%	0%	4%	0%	0%	0%	1%	18%
FL	Melbourne	MLB	35%	22%	9%	3%	0%	0%	0%	0%	0%	2%	7%	22%
FL	Miami	MIA	43%	23%	7%	0%	0%	0%	0%	0%	0%	0%	3%	25%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
FL	Orlando	MCO	35%	22%	9%	2%	0%	0%	0%	0%	0%	2%	7%	24%
FL	Pensacola	PNS	28%	22%	9%	3%	0%	0%	0%	0%	0%	3%	11%	24%
FL	Tallahassee	TLH	27%	21%	10%	3%	0%	0%	0%	0%	0%	3%	12%	24%
FL	Tampa	TPA	35%	22%	9%	2%	0%	0%	0%	0%	0%	1%	6%	25%
FL	Vero Beach	VRB	35%	23%	10%	3%	0%	0%	0%	0%	0%	1%	6%	22%
FL	West Palm Beach	PBI	39%	22%	8%	2%	0%	0%	0%	0%	0%	1%	5%	23%
GA	Albany	ABY	27%	21%	10%	3%	0%	0%	0%	0%	0%	3%	12%	24%
GA	Athens	AHN	24%	19%	11%	5%	1%	0%	0%	0%	0%	5%	13%	22%
GA	Atlanta	ATL	25%	20%	11%	5%	1%	0%	0%	0%	0%	4%	12%	22%
GA	Augusta	AGS	25%	20%	11%	4%	0%	0%	0%	0%	0%	4%	13%	22%
GA	Brunswick	SSI	28%	22%	10%	4%	0%	0%	0%	0%	0%	2%	10%	23%
GA	Columbus	CSG	27%	21%	10%	3%	0%	0%	0%	0%	0%	3%	12%	23%
GA	Macon	MCN	25%	20%	11%	4%	0%	0%	0%	0%	0%	4%	13%	23%
GA	Savannah	SAV	27%	21%	11%	4%	0%	0%	0%	0%	0%	3%	12%	22%
GA	Waycross	AYS	27%	21%	9%	3%	0%	1%	0%	0%	0%	3%	12%	24%
HI	Hilo-Hawaii	ITO	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
HI	Honolulu-Oahu	HNL	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
HI	Kahului-Maui	OGG	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HI	Lihue-Kauai	LIH	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
IA	Burlington	BRL	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	11%	20%
IA	Cedar Rapids	CID	21%	18%	12%	7%	3%	0%	0%	0%	2%	7%	11%	19%
IA	Des Moines	DSM	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
IA	Dubuque	DBQ	21%	18%	12%	7%	3%	0%	0%	0%	2%	7%	11%	19%
IA	Mason City	MCW	20%	17%	12%	7%	3%	0%	0%	0%	2%	7%	12%	18%
IA	Ottumwa	OTM	22%	18%	12%	6%	3%	0%	0%	0%	2%	7%	12%	19%
IA	Sioux City	SUX	21%	18%	12%	6%	3%	0%	0%	0%	2%	7%	12%	19%
IA	Waterloo	ALO	21%	18%	12%	7%	3%	0%	0%	0%	2%	7%	12%	19%
ID	Boise	BOI	19%	15%	12%	8%	4%	1%	0%	0%	1%	7%	14%	19%
ID	Burley	BYI	17%	15%	12%	9%	5%	2%	0%	0%	3%	8%	13%	17%
ID	Idaho Falls	IDA	18%	15%	12%	8%	5%	2%	0%	0%	3%	8%	12%	17%
ID	Lewiston	LWS	18%	15%	12%	8%	4%	1%	0%	0%	1%	8%	14%	19%
ID	Pocatello	PIH	18%	15%	12%	8%	5%	2%	0%	0%	3%	8%	13%	17%
IL	Chicago	ORD	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	11%	18%
IL	Moline	MLI	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	11%	19%
IL	Peoria	PIA	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
IL	Quincy	UIN	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
IL	Rockford	RFD	21%	18%	13%	7%	3%	0%	0%	0%	2%	6%	11%	19%
IL	Springfield	SPI	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	11%	20%
IN	Evansville	EVV	23%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
IN	Fort Wayne	FWA	21%	18%	13%	7%	3%	0%	0%	0%	1%	7%	11%	18%
IN	Indianapolis	IND	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
IN	South Bend	SBN	21%	18%	13%	7%	3%	0%	0%	0%	2%	7%	11%	18%
IN	West Lafayette	LAF	22%	19%	12%	6%	3%	0%	0%	0%	1%	6%	11%	19%
KS	Concordia	CNK	22%	18%	11%	6%	2%	0%	0%	0%	1%	6%	12%	21%
KS	Dodge City	DDC	21%	18%	12%	7%	2%	0%	0%	0%	1%	6%	13%	21%
KS	Garden City	GCK	21%	18%	12%	7%	2%	0%	0%	0%	1%	6%	13%	21%
KS	Goodland	GLD	19%	17%	12%	8%	3%	0%	0%	0%	2%	7%	13%	19%
KS	Russell	RSL	21%	18%	12%	6%	2%	0%	0%	0%	1%	6%	13%	21%
KS	Salina	SLN	22%	19%	11%	6%	2%	0%	0%	0%	1%	5%	12%	21%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
KS	Topeka	TOP	23%	19%	11%	6%	2%	0%	0%	0%	1%	6%	12%	20%
KS	Wichita	ICT	23%	19%	11%	6%	2%	0%	0%	0%	1%	5%	12%	22%
KY	Bowling Green	BWG	23%	19%	11%	6%	2%	0%	0%	0%	1%	6%	12%	20%
KY	Jackson	JKL	23%	19%	12%	6%	2%	0%	0%	0%	1%	6%	11%	20%
KY	Lexington	LEX	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
KY	Louisville	SDF	24%	20%	12%	5%	1%	0%	0%	0%	0%	5%	12%	20%
KY	Paducah	PAH	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
LA	Baton Rouge	BTR	27%	21%	9%	3%	0%	0%	0%	0%	0%	3%	12%	25%
LA	Lafayette	LFT	28%	21%	9%	2%	0%	0%	0%	0%	0%	3%	11%	26%
LA	Lake Charles	LCH	28%	22%	9%	2%	0%	0%	0%	0%	0%	2%	11%	25%
LA	Monroe	MLU	26%	21%	10%	3%	0%	0%	0%	0%	0%	4%	12%	24%
LA	New Orleans	MSY	29%	22%	8%	2%	0%	0%	0%	0%	0%	2%	10%	26%
LA	Shreveport	SHV	26%	21%	10%	3%	0%	0%	0%	0%	0%	3%	12%	25%
MA	Boston	BOS	20%	17%	15%	9%	4%	1%	0%	0%	1%	6%	11%	17%
MA	Worcester	ORH	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
MD	Baltimore	BWI	22%	19%	13%	7%	2%	0%	0%	0%	1%	6%	11%	19%
MD	Salisbury	SBY	21%	19%	14%	8%	3%	0%	0%	0%	1%	6%	11%	18%
ME	Augusta	AUG	20%	16%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
ME	Bangor	BGR	19%	16%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
ME	Caribou	CAR	19%	16%	14%	8%	5%	2%	0%	1%	3%	7%	10%	16%
ME	Houlton	HUL	18%	16%	13%	9%	5%	2%	1%	1%	3%	7%	10%	15%
ME	Portland	PWM	19%	16%	14%	9%	5%	1%	0%	0%	2%	7%	11%	16%
MI	Alpena	APN	18%	16%	14%	9%	5%	2%	0%	1%	3%	7%	11%	16%
MI	Detroit	DTW	21%	18%	14%	7%	3%	0%	0%	0%	1%	6%	11%	18%
MI	Flint	FNT	20%	17%	13%	8%	4%	1%	0%	0%	2%	7%	11%	17%
MI	Grand Rapids	GRR	20%	18%	13%	8%	4%	1%	0%	0%	2%	7%	11%	17%
MI	Houghton Lake	HTL	18%	16%	13%	8%	4%	1%	0%	1%	3%	7%	11%	16%
MI	Jackson	JXN	20%	17%	13%	7%	4%	1%	0%	0%	2%	7%	11%	17%
MI	Lansing	LAN	20%	17%	13%	8%	4%	1%	0%	0%	2%	7%	11%	17%
MI	Marquette	MQT	17%	15%	13%	9%	5%	2%	1%	1%	3%	7%	11%	16%
MI	Muskegon	MKG	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
MI	Saginaw	MBS	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
MI	Sault St Marie	SSM	18%	16%	14%	9%	5%	2%	1%	1%	3%	7%	10%	16%
MI	Traverse City	TVC	18%	17%	14%	9%	5%	1%	0%	0%	2%	7%	11%	16%
MN	Alexandria	AXN	20%	17%	13%	7%	4%	1%	0%	0%	2%	7%	12%	18%
MN	Duluth	DLH	19%	16%	13%	8%	5%	2%	0%	1%	3%	7%	11%	17%
MN	Hibbing	HIB	18%	15%	12%	8%	5%	2%	1%	1%	3%	7%	11%	16%
MN	Int'l Falls	INL	19%	16%	12%	7%	4%	2%	1%	1%	3%	7%	11%	17%
MN	Minneapolis	MSP	21%	18%	13%	6%	3%	0%	0%	0%	2%	6%	12%	19%
MN	Rochester	RST	21%	18%	13%	7%	3%	1%	0%	0%	2%	7%	11%	18%
MN	Saint Cloud	STC	20%	17%	13%	7%	4%	1%	0%	0%	2%	7%	12%	18%
MO	Columbia	COU	23%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
MO	Joplin	JLN	23%	19%	11%	6%	2%	0%	0%	0%	1%	6%	11%	21%
MO	Kansas City	MCI	23%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
MO	Saint Louis	STL	23%	20%	12%	5%	2%	0%	0%	0%	1%	5%	12%	21%
MO	Springfield	SGF	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
MS	Greenwood	GWO	25%	20%	10%	4%	1%	0%	0%	0%	0%	5%	11%	23%
MS	McComb	MCB	26%	21%	9%	3%	0%	0%	0%	0%	0%	4%	12%	24%
MS	Tupelo	TUP	25%	20%	11%	4%	1%	0%	0%	0%	0%	5%	12%	22%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MT	Billings	BIL	18%	15%	12%	8%	5%	1%	0%	0%	2%	8%	13%	18%
MT	Butte	BTM	15%	13%	11%	9%	6%	3%	1%	1%	4%	8%	12%	16%
MT	Cut Bank	CTB	16%	14%	12%	9%	6%	3%	1%	1%	4%	8%	12%	16%
MT	Great Falls	GTF	16%	14%	12%	9%	6%	3%	0%	1%	3%	8%	12%	16%
MT	Havre	HVR	18%	16%	12%	7%	5%	2%	0%	1%	3%	8%	12%	17%
MT	Helena	HLN	17%	14%	12%	8%	5%	2%	0%	0%	3%	8%	13%	18%
MT	Kalispell	FCA	17%	14%	12%	8%	4%	2%	0%	1%	3%	8%	13%	17%
MT	Lewistown	LWT	16%	14%	12%	9%	6%	3%	1%	1%	3%	8%	12%	16%
MT	Miles City	MLS	19%	16%	12%	7%	4%	1%	0%	0%	2%	7%	13%	18%
MT	Missoula	MSO	17%	14%	11%	8%	5%	2%	0%	0%	3%	8%	13%	17%
NC	Asheville	AVL	21%	18%	12%	7%	2%	0%	0%	0%	1%	7%	13%	19%
NC	Cape Hatteras	HAT	27%	24%	16%	6%	1%	0%	0%	0%	0%	1%	6%	18%
NC	Charlotte	CLT	23%	19%	12%	5%	1%	0%	0%	0%	0%	5%	13%	21%
NC	Greensboro	GSO	23%	19%	12%	6%	2%	0%	0%	0%	0%	5%	13%	20%
NC	Hickory	HKY	23%	19%	12%	6%	2%	0%	0%	0%	0%	6%	12%	21%
NC	New Bern	EWN	24%	20%	13%	5%	1%	0%	0%	0%	0%	4%	12%	20%
NC	Raleigh Durham	RDU	23%	19%	12%	5%	1%	0%	0%	0%	0%	5%	12%	21%
NC	Wilmington	ILM	24%	20%	13%	5%	1%	0%	0%	0%	0%	4%	12%	21%
ND	Bismarck	BIS	19%	17%	13%	7%	4%	1%	0%	0%	2%	7%	12%	18%
ND	Devil's Lake	P11	19%	17%	13%	7%	4%	1%	0%	0%	2%	7%	12%	17%
ND	Fargo	FAR	20%	18%	13%	7%	3%	1%	0%	0%	2%	7%	12%	18%
ND	Grand Forks	GFK	19%	17%	13%	7%	4%	1%	0%	0%	2%	7%	12%	17%
ND	Minot	MOT	19%	17%	13%	7%	4%	1%	0%	0%	2%	7%	12%	17%
ND	Williston	ISN	18%	16%	12%	7%	4%	1%	0%	0%	3%	7%	12%	18%
NE	Grand Island	GRI	21%	18%	12%	7%	3%	0%	0%	0%	1%	7%	12%	20%
NE	Lincoln	LNK	21%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
NE	Norfolk	OFK	21%	17%	12%	7%	3%	0%	0%	0%	2%	7%	12%	19%
NE	North Platte	LBF	19%	16%	12%	8%	4%	1%	0%	0%	2%	7%	13%	19%
NE	Omaha	OMA	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
NE	Scottsbluff	BFF	18%	16%	12%	8%	4%	1%	0%	0%	2%	8%	13%	19%
NE	Valentine	VTN	19%	17%	12%	8%	4%	1%	0%	0%	2%	7%	13%	18%
NH	Concord	CON	20%	16%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
NH	Lebanon	LEB	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
NJ	Atlantic City	ACY	21%	18%	14%	8%	3%	0%	0%	0%	1%	6%	11%	18%
NJ	Newark	EWR	22%	19%	14%	7%	2%	0%	0%	0%	0%	5%	11%	18%
NM	Albuquerque	ABQ	21%	17%	12%	6%	2%	0%	0%	0%	0%	5%	14%	22%
NM	Carlsbad	CNM	24%	19%	10%	3%	1%	0%	0%	0%	0%	4%	14%	25%
NM	Clayton	CAO	19%	18%	13%	8%	3%	0%	0%	0%	1%	6%	13%	20%
NM	Gallup	GUP	18%	15%	13%	9%	5%	1%	0%	0%	2%	8%	13%	18%
NM	Roswell	ROW	23%	18%	10%	4%	1%	0%	0%	0%	0%	4%	14%	25%
NV	Elko	EKO	18%	15%	12%	9%	5%	2%	0%	0%	2%	8%	13%	17%
NV	Ely	ELY	17%	14%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
NV	Las Vegas	LAS	26%	19%	9%	3%	0%	0%	0%	0%	0%	2%	12%	29%
NV	Lovelock	LOL	19%	15%	12%	8%	3%	1%	0%	0%	1%	7%	14%	20%
NV	Reno	RNO	19%	15%	12%	9%	4%	1%	0%	0%	1%	6%	13%	19%
NV	Tonopah	TPH	18%	15%	13%	9%	4%	1%	0%	0%	1%	7%	13%	19%
NV	Winnemucca	WMC	17%	14%	12%	9%	5%	2%	0%	0%	2%	8%	13%	18%
NY	Albany	ALB	20%	17%	14%	8%	3%	1%	0%	0%	2%	7%	11%	17%
NY	Binghamton	BGM	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NY	Buffalo	BUF	19%	18%	14%	9%	4%	1%	0%	0%	1%	7%	11%	16%
NY	Glens Falls	GFL	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
NY	Massena	MSS	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
NY	New York	LGA	22%	19%	15%	8%	3%	0%	0%	0%	0%	5%	10%	18%
NY	Rochester	ROC	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
NY	Syracuse	SYR	20%	18%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
NY	Utica	UCA	22%	18%	14%	7%	3%	1%	0%	0%	1%	6%	11%	18%
NY	Watertown	ART	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	10%	16%
OH	Akron Canton	CAK	20%	18%	13%	7%	3%	1%	0%	0%	2%	7%	11%	17%
OH	Cincinnati	CVG	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
OH	Cleveland	CLE	20%	18%	14%	8%	3%	1%	0%	0%	1%	6%	11%	17%
OH	Columbus	CMH	22%	19%	13%	6%	2%	0%	0%	0%	1%	6%	11%	19%
OH	Dayton	DAY	21%	18%	13%	7%	3%	0%	0%	0%	1%	7%	11%	18%
OH	Findlay	FDY	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	11%	18%
OH	Mansfield	MFD	20%	18%	13%	7%	3%	1%	0%	0%	2%	7%	11%	17%
OH	Toledo	TOL	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	11%	18%
OH	Youngstown	YNG	20%	18%	13%	8%	4%	1%	0%	0%	2%	7%	11%	17%
OK	Hobart	HBR	23%	19%	11%	5%	1%	0%	0%	0%	0%	5%	12%	23%
OK	McAlester	MLC	25%	20%	10%	5%	1%	0%	0%	0%	0%	5%	11%	23%
OK	Oklahoma City	OKC	24%	20%	11%	5%	1%	0%	0%	0%	0%	4%	12%	23%
OK	Tulsa	TUL	24%	20%	11%	5%	1%	0%	0%	0%	0%	5%	12%	23%
OR	Astoria	AST	13%	12%	12%	10%	7%	5%	3%	2%	4%	7%	11%	14%
OR	Baker	BKE	16%	13%	11%	9%	6%	3%	1%	1%	3%	8%	13%	16%
OR	Eugene	EUG	15%	13%	12%	10%	7%	3%	0%	0%	2%	8%	13%	16%
OR	Medford	MFR	18%	14%	12%	9%	4%	1%	0%	0%	1%	7%	14%	19%
OR	Pendleton	PDT	17%	14%	12%	9%	5%	2%	0%	0%	2%	8%	14%	19%
OR	Portland	PDX	17%	14%	12%	9%	5%	2%	0%	0%	1%	7%	13%	18%
OR	Redmond	RDM	15%	13%	12%	10%	6%	3%	1%	1%	3%	8%	12%	16%
OR	Salem	SLE	16%	14%	12%	10%	6%	3%	0%	0%	2%	7%	13%	17%
PA	Allentown	ABE	21%	18%	14%	8%	3%	0%	0%	0%	1%	7%	11%	18%
PA	Altoona	AOO	20%	18%	13%	7%	3%	1%	0%	0%	2%	7%	11%	17%
PA	Bradford	BFD	18%	16%	13%	8%	5%	2%	1%	1%	3%	8%	11%	15%
PA	Du Bois	DUJ	19%	17%	13%	8%	4%	1%	0%	0%	2%	7%	11%	17%
PA	Erie	ERI	19%	18%	15%	9%	4%	1%	0%	0%	1%	6%	10%	16%
PA	Harrisburg	CXY	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	11%	18%
PA	Philadelphia	PHL	22%	19%	14%	7%	2%	0%	0%	0%	0%	5%	11%	19%
PA	Pittsburgh	PIT	21%	18%	13%	7%	3%	0%	0%	0%	1%	7%	11%	18%
PA	Williamsport	IPT	21%	18%	14%	7%	3%	0%	0%	0%	1%	7%	11%	18%
RI	Providence	PVD	20%	17%	14%	8%	4%	1%	0%	0%	1%	6%	11%	17%
SC	Charleston	CHS	27%	21%	11%	4%	0%	0%	0%	0%	0%	3%	12%	22%
SC	Columbia	CAE	25%	20%	11%	4%	1%	0%	0%	0%	0%	4%	13%	22%
SC	Florence	FLO	25%	20%	12%	5%	1%	0%	0%	0%	0%	4%	12%	21%
SC	Greenville	GSP	23%	19%	12%	5%	1%	0%	0%	0%	0%	5%	13%	22%
SD	Aberdeen	ABR	20%	17%	12%	7%	3%	1%	0%	0%	2%	7%	12%	18%
SD	Huron	HON	20%	17%	12%	7%	3%	1%	0%	0%	2%	7%	12%	18%
SD	Pierre	PIR	19%	17%	12%	7%	4%	1%	0%	0%	2%	7%	12%	18%
SD	Rapid City	RAP	18%	16%	12%	8%	5%	1%	0%	0%	2%	7%	12%	18%
SD	Sioux Falls	FSD	20%	17%	12%	7%	3%	0%	0%	0%	2%	7%	12%	19%
TN	Bristol	TRI	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	13%	20%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
TN	Chattanooga	CHA	24%	19%	11%	5%	1%	0%	0%	0%	0%	5%	13%	22%
TN	Crossville	CSV	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
TN	Jackson	MKL	24%	20%	11%	5%	1%	0%	0%	0%	0%	6%	12%	21%
TN	Knoxville	TYS	23%	19%	11%	5%	1%	0%	0%	0%	0%	6%	13%	21%
TN	Memphis	MEM	25%	21%	11%	4%	1%	0%	0%	0%	0%	4%	12%	23%
TN	Nashville	BNA	24%	19%	11%	5%	1%	0%	0%	0%	0%	5%	12%	21%
TX	Abilene	ABI	25%	20%	10%	3%	1%	0%	0%	0%	0%	4%	12%	25%
TX	Alice	ALI	31%	23%	7%	1%	0%	0%	0%	0%	0%	1%	8%	29%
TX	Amarillo	AMA	21%	18%	12%	6%	2%	0%	0%	0%	1%	6%	13%	21%
TX	Austin	AUS	27%	21%	10%	3%	0%	0%	0%	0%	0%	3%	11%	25%
TX	Brownsville	BRO	31%	24%	6%	2%	0%	0%	0%	0%	0%	0%	6%	31%
TX	College Station	CLL	29%	22%	9%	2%	0%	0%	0%	0%	0%	2%	10%	26%
TX	Corpus Christi	CRP	32%	22%	7%	1%	0%	0%	0%	0%	0%	1%	8%	28%
TX	Dallas-Ft. Worth	DFW	27%	22%	10%	3%	0%	0%	0%	0%	0%	3%	11%	25%
TX	Del Rio	DRT	30%	20%	6%	1%	0%	0%	0%	0%	0%	1%	11%	30%
TX	El Paso	ELP	25%	19%	10%	3%	0%	0%	0%	0%	0%	2%	14%	27%
TX	Galveston	GLS	32%	25%	8%	1%	0%	0%	0%	0%	0%	1%	7%	26%
TX	Houston	IAH	29%	22%	8%	2%	0%	0%	0%	0%	0%	2%	10%	27%
TX	Laredo	LRD	33%	22%	5%	1%	0%	0%	0%	0%	0%	1%	7%	31%
TX	Lubbock	LBB	23%	19%	11%	5%	1%	0%	0%	0%	0%	5%	13%	23%
TX	Lufkin	LFK	27%	21%	9%	3%	0%	0%	0%	0%	0%	3%	12%	25%
TX	McAllen	MFE	33%	24%	5%	2%	0%	0%	0%	0%	0%	1%	6%	30%
TX	Midland Odessa	MAF	25%	19%	10%	3%	1%	0%	0%	0%	0%	3%	13%	25%
TX	San Angelo	SJT	26%	20%	9%	3%	0%	0%	0%	0%	0%	3%	12%	25%
TX	San Antonio	SAT	29%	21%	8%	2%	0%	0%	0%	0%	0%	2%	10%	27%
TX	Victoria	VCT	30%	21%	8%	2%	0%	0%	0%	0%	0%	2%	10%	27%
TX	Waco	ACT	27%	21%	10%	3%	0%	0%	0%	0%	0%	3%	11%	25%
TX	Wichita Falls	SPS	25%	21%	10%	4%	1%	0%	0%	0%	0%	4%	12%	24%
UT	Cedar City	CDC	18%	15%	12%	9%	4%	1%	0%	0%	2%	7%	13%	18%
UT	Salt Lake City	SLC	20%	16%	12%	8%	4%	1%	0%	0%	1%	6%	13%	19%
VA	Lynchburg	LYH	21%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
VA	Norfolk	ORF	23%	20%	14%	6%	2%	0%	0%	0%	0%	4%	11%	19%
VA	Richmond	RIC	23%	20%	13%	6%	2%	0%	0%	0%	0%	5%	11%	20%
VA	Roanoke	ROA	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
VT	Burlington	BTV	20%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
VT	Montpelier	MPV	19%	16%	13%	8%	4%	1%	0%	1%	3%	7%	11%	16%
WA	Bellingham	BLI	14%	13%	12%	9%	6%	4%	1%	1%	4%	8%	12%	15%
WA	Olympia	OLM	14%	13%	12%	10%	6%	3%	1%	1%	3%	8%	12%	15%
WA	Quillayute	UIL	12%	11%	12%	10%	8%	5%	3%	3%	4%	8%	11%	13%
WA	Seattle Tacoma	SEA	15%	13%	13%	10%	6%	3%	1%	1%	3%	8%	13%	16%
WA	Spokane	GEG	17%	14%	12%	9%	5%	2%	0%	0%	2%	8%	14%	18%
WA	Walla Walla	ALW	18%	15%	11%	8%	4%	1%	0%	0%	1%	7%	14%	20%
WA	Yakima	YKM	18%	14%	11%	8%	4%	1%	0%	0%	2%	8%	14%	19%
WI	Eau Claire	EAU	20%	17%	13%	7%	3%	1%	0%	0%	2%	7%	11%	18%
WI	Green Bay	GRB	20%	17%	13%	8%	4%	1%	0%	0%	2%	7%	11%	17%
WI	Lacrosse	LSE	21%	18%	13%	7%	3%	0%	0%	0%	2%	6%	11%	19%
WI	Madison	MSN	20%	17%	13%	7%	3%	1%	0%	0%	2%	7%	11%	18%
WI	Milwaukee	MKE	20%	17%	13%	8%	4%	1%	0%	0%	2%	6%	11%	17%
WI	Wausau	AUW	20%	17%	13%	7%	4%	1%	0%	0%	2%	7%	11%	17%

Station Location		Code	Monthly Heating Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
WV	Beckley	BKW	20%	17%	12%	7%	3%	1%	0%	0%	2%	7%	12%	18%
WV	Charleston	CRW	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
WV	Elkins	EKN	19%	17%	13%	8%	4%	1%	0%	0%	2%	7%	12%	17%
WV	Huntington	HTS	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
WV	Martinsburg	MRB	21%	18%	13%	7%	3%	0%	0%	0%	1%	7%	12%	19%
WV	Morgantown	MGW	21%	18%	13%	7%	3%	0%	0%	0%	1%	7%	11%	18%
WV	Parkersburg	PKB	22%	18%	13%	6%	3%	0%	0%	0%	1%	7%	12%	19%
WY	Casper	CPR	16%	15%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
WY	Cheyenne	CYS	16%	15%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
WY	Cody	COD	17%	15%	11%	9%	5%	2%	0%	1%	3%	8%	12%	17%
WY	Lander	LND	18%	15%	11%	8%	5%	2%	0%	0%	2%	8%	12%	18%
WY	Rock Springs	RKS	17%	15%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
WY	Sheridan	SHR	17%	15%	12%	8%	6%	2%	0%	0%	3%	8%	12%	17%
WY	Worland	WRL	19%	16%	11%	7%	4%	1%	0%	0%	2%	7%	13%	19%

Table 7C.3.5 Weather Station Monthly Cooling Degree Day Data Fractions (10-Year Average)

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AK	Anchorage	ANC	0%	0%	0%	0%	0%	12%	71%	17%	0%	0%	0%	0%
AK	Bethel	BET	0%	0%	0%	0%	0%	28%	38%	35%	0%	0%	0%	0%
AK	Cold Bay	CDB	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
AK	Cordova	CDV	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%
AK	Homer	HOM	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
AK	Juneau	JNU	0%	0%	0%	0%	0%	51%	29%	20%	0%	0%	0%	0%
AK	Kenai	ENA	0%	0%	0%	0%	0%	0%	56%	11%	0%	0%	33%	0%
AK	Ketchikan	KTN	0%	0%	0%	0%	0%	27%	42%	31%	0%	0%	0%	0%
AK	King Salmon	AKN	0%	0%	0%	0%	0%	4%	30%	65%	0%	0%	0%	0%
AK	Kodiak	ADQ	0%	0%	0%	0%	0%	5%	73%	22%	0%	0%	0%	0%
AK	Sitka	SIT	0%	0%	0%	0%	0%	24%	11%	66%	0%	0%	0%	0%
AK	St Paul Island	SNP	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
AK	Talkeetna	TKA	0%	0%	0%	0%	0%	23%	53%	24%	0%	0%	0%	0%
AK	Valdez	VWS	0%	0%	0%	0%	20%	16%	36%	28%	0%	0%	0%	0%
AK	Yakutat	YAK	0%	0%	0%	0%	0%	0%	25%	75%	0%	0%	0%	0%
AL	Birmingham	BHM	0%	0%	2%	4%	11%	19%	23%	23%	14%	4%	1%	0%
AL	Huntsville	HSV	0%	0%	1%	3%	11%	20%	24%	24%	13%	3%	0%	0%
AL	Mobile	MOB	0%	0%	2%	4%	12%	18%	20%	20%	15%	6%	2%	1%
AL	Montgomery	MGM	0%	0%	2%	4%	11%	19%	22%	22%	15%	5%	1%	0%
AL	Muscle Shoals	MSL	0%	0%	1%	4%	11%	19%	24%	24%	13%	3%	0%	0%
AL	Tuscaloosa	TCL	0%	0%	1%	4%	11%	19%	23%	23%	14%	4%	1%	0%
AR	Fayetteville	FYV	0%	0%	1%	2%	8%	20%	28%	29%	10%	2%	0%	0%
AR	Fort Smith	FSM	0%	0%	1%	3%	10%	19%	25%	25%	13%	4%	0%	0%
AR	Little Rock	LIT	0%	0%	1%	3%	10%	20%	24%	25%	13%	4%	0%	0%
AR	Texarkana	TXK	0%	0%	2%	4%	11%	19%	23%	23%	13%	4%	1%	0%
AZ	Douglas	DUG	0%	0%	0%	2%	10%	22%	25%	22%	15%	4%	0%	0%
AZ	Flagstaff	FLG	0%	0%	0%	0%	0%	13%	60%	26%	1%	0%	0%	0%
AZ	Phoenix	PHX	0%	0%	2%	5%	11%	17%	20%	19%	15%	8%	2%	0%
AZ	Tucson	TUS	0%	0%	1%	4%	11%	19%	21%	20%	15%	7%	1%	0%

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AZ	Winslow	INW	0%	0%	0%	0%	6%	20%	34%	27%	11%	1%	0%	0%
AZ	Yuma	NYL	0%	0%	3%	5%	11%	15%	20%	19%	16%	8%	2%	0%
CA	Bakersfield	BFL	0%	0%	1%	2%	9%	17%	26%	24%	17%	5%	0%	0%
CA	Blythe	BLH	0%	0%	2%	5%	11%	16%	21%	20%	15%	7%	1%	0%
CA	Eureka	EKA	0%	0%	0%	4%	10%	5%	5%	24%	17%	31%	4%	0%
CA	Fresno	FAT	0%	0%	0%	2%	9%	17%	27%	24%	17%	5%	0%	0%
CA	Los Angeles	LAX	2%	1%	2%	3%	4%	7%	22%	24%	20%	12%	4%	0%
CA	Mt Shasta	MHS	0%	0%	0%	0%	4%	10%	44%	32%	10%	0%	0%	0%
CA	Paso Robles	PRB	0%	0%	0%	1%	6%	15%	29%	27%	18%	4%	0%	0%
CA	Red Bluff	RBL	0%	0%	0%	1%	7%	18%	28%	24%	16%	4%	0%	0%
CA	Redding	RDD	0%	0%	0%	1%	7%	18%	29%	25%	16%	4%	0%	0%
CA	Sacramento	SAC	0%	0%	0%	1%	7%	17%	28%	25%	18%	4%	0%	0%
CA	San Diego	SAN	1%	0%	1%	2%	4%	7%	22%	27%	22%	10%	3%	0%
CA	San Francisco	SFO	0%	0%	1%	3%	6%	12%	13%	19%	31%	14%	1%	0%
CA	Stockton	SCK	0%	0%	0%	2%	7%	17%	28%	25%	17%	4%	0%	0%
CO	Alamosa	ALS	0%	0%	0%	0%	0%	11%	62%	26%	1%	0%	0%	0%
CO	Colorado Spring	COS	0%	0%	0%	0%	3%	20%	42%	28%	7%	0%	0%	0%
CO	Denver	DEN	0%	0%	0%	0%	4%	17%	39%	31%	9%	1%	0%	0%
CO	Eagle	EGE	0%	0%	0%	0%	1%	13%	55%	30%	1%	0%	0%	0%
CO	Pueblo	PUB	0%	0%	0%	0%	4%	20%	38%	29%	8%	1%	0%	0%
CO	Trinidad	TAD	0%	0%	0%	0%	4%	20%	37%	29%	9%	1%	0%	0%
CT	Bridgeport	BDR	0%	0%	0%	0%	3%	17%	35%	32%	13%	1%	0%	0%
CT	Hartford	BDL	0%	0%	0%	1%	5%	18%	35%	30%	10%	1%	0%	0%
DC	Washington	DCA	0%	0%	0%	2%	7%	20%	29%	27%	13%	2%	0%	0%
DE	Wilmington	ILG	0%	0%	0%	1%	6%	19%	32%	28%	12%	2%	0%	0%
FL	Daytona Beach	DAB	1%	1%	3%	5%	11%	15%	17%	17%	15%	10%	3%	2%
FL	Fort Myers	FMY	2%	3%	5%	7%	11%	13%	14%	14%	13%	10%	5%	3%
FL	Ft Lauderdale	FLL	3%	4%	6%	7%	10%	12%	13%	13%	12%	10%	6%	5%
FL	Gainesville	GNV	1%	1%	2%	5%	12%	16%	18%	19%	15%	8%	2%	1%
FL	Jacksonville	JAX	0%	1%	2%	4%	11%	17%	20%	20%	15%	8%	2%	1%
FL	Key West	EYW	3%	4%	6%	7%	10%	11%	13%	13%	12%	10%	7%	4%
FL	Melbourne	MLB	1%	2%	4%	6%	11%	14%	15%	16%	14%	10%	5%	3%
FL	Miami	MIA	3%	4%	6%	7%	10%	12%	13%	13%	12%	10%	6%	4%
FL	Orlando	MCO	1%	2%	4%	6%	11%	14%	16%	16%	14%	9%	4%	2%
FL	Pensacola	PNS	0%	0%	2%	4%	12%	18%	20%	19%	15%	7%	2%	0%
FL	Tallahassee	TLH	0%	0%	2%	4%	12%	18%	20%	20%	15%	7%	1%	0%
FL	Tampa	TPA	1%	2%	4%	6%	12%	14%	15%	16%	14%	10%	4%	2%
FL	Vero Beach	VRB	2%	2%	4%	6%	11%	13%	15%	15%	14%	10%	5%	3%
FL	West Palm Beach	PBI	2%	3%	5%	7%	11%	12%	14%	14%	12%	10%	6%	4%
GA	Albany	ABY	0%	0%	2%	4%	12%	18%	21%	20%	15%	6%	1%	0%
GA	Athens	AHN	0%	0%	1%	3%	10%	20%	25%	25%	14%	3%	0%	0%
GA	Atlanta	ATL	0%	0%	1%	3%	10%	20%	24%	24%	14%	4%	0%	0%
GA	Augusta	AGS	0%	0%	1%	3%	10%	19%	24%	24%	15%	4%	0%	0%
GA	Brunswick	SSI	0%	0%	2%	4%	11%	17%	20%	20%	15%	7%	2%	1%
GA	Columbus	CSG	0%	0%	1%	4%	11%	19%	22%	22%	15%	5%	1%	0%
GA	Macon	MCN	0%	0%	1%	3%	11%	20%	23%	23%	14%	4%	1%	0%
GA	Savannah	SAV	0%	0%	1%	4%	11%	18%	21%	21%	15%	6%	1%	0%
GA	Waycross	AYS	0%	0%	2%	5%	12%	17%	20%	20%	15%	6%	1%	1%
HI	Hilo-Hawaii	ITO	6%	6%	7%	7%	9%	9%	10%	11%	10%	10%	8%	7%

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
HI	Honolulu-Oahu	HNL	6%	5%	7%	7%	9%	10%	11%	11%	10%	10%	8%	7%
HI	Kahului-Maui	OGG	6%	5%	6%	7%	9%	10%	11%	11%	10%	10%	8%	7%
HI	Lihue-Kauai	LIH	6%	5%	6%	7%	9%	10%	11%	11%	11%	10%	8%	7%
IA	Burlington	BRL	0%	0%	0%	2%	8%	21%	31%	26%	10%	2%	0%	0%
IA	Cedar Rapids	CID	0%	0%	0%	1%	7%	21%	34%	26%	8%	2%	0%	0%
IA	Des Moines	DSM	0%	0%	0%	1%	7%	21%	33%	27%	9%	2%	0%	0%
IA	Dubuque	DBQ	0%	0%	0%	1%	6%	21%	35%	27%	9%	2%	0%	0%
IA	Mason City	MCW	0%	0%	0%	1%	6%	21%	37%	26%	8%	2%	0%	0%
IA	Ottumwa	OTM	0%	0%	0%	2%	7%	21%	33%	27%	8%	2%	0%	0%
IA	Sioux City	SUX	0%	0%	0%	1%	7%	21%	35%	26%	8%	2%	0%	0%
IA	Waterloo	ALO	0%	0%	0%	1%	6%	21%	35%	25%	9%	2%	0%	0%
ID	Boise	BOI	0%	0%	0%	0%	4%	13%	39%	32%	11%	1%	0%	0%
ID	Burley	BYI	0%	0%	0%	0%	3%	11%	48%	34%	4%	1%	0%	0%
ID	Idaho Falls	IDA	0%	0%	0%	0%	2%	9%	51%	35%	2%	0%	0%	0%
ID	Lewiston	LWS	0%	0%	0%	0%	3%	11%	40%	34%	11%	1%	0%	0%
ID	Pocatello	PIH	0%	0%	0%	0%	2%	10%	49%	36%	3%	0%	0%	0%
IL	Chicago	ORD	0%	0%	0%	1%	6%	20%	34%	28%	10%	2%	0%	0%
IL	Moline	MLI	0%	0%	0%	1%	7%	21%	33%	26%	9%	2%	0%	0%
IL	Peoria	PIA	0%	0%	0%	1%	7%	21%	32%	26%	10%	2%	0%	0%
IL	Quincy	UIN	0%	0%	0%	2%	8%	20%	31%	27%	9%	2%	0%	0%
IL	Rockford	RFD	0%	0%	1%	1%	6%	21%	34%	27%	10%	2%	0%	0%
IL	Springfield	SPI	0%	0%	1%	2%	9%	21%	29%	26%	10%	2%	0%	0%
IN	Evansville	EVV	0%	0%	1%	2%	9%	21%	28%	26%	11%	2%	0%	0%
IN	Fort Wayne	FWA	0%	0%	0%	1%	7%	22%	34%	25%	9%	1%	0%	0%
IN	Indianapolis	IND	0%	0%	1%	2%	8%	21%	29%	27%	11%	2%	0%	0%
IN	South Bend	SBN	0%	0%	1%	1%	7%	21%	33%	26%	10%	2%	0%	0%
IN	West Lafayette	LAF	0%	0%	1%	2%	8%	21%	30%	26%	11%	2%	0%	0%
KS	Concordia	CNK	0%	0%	0%	1%	7%	21%	32%	27%	10%	2%	0%	0%
KS	Dodge City	DDC	0%	0%	0%	1%	7%	21%	31%	27%	10%	2%	0%	0%
KS	Garden City	GCK	0%	0%	0%	1%	7%	20%	31%	27%	11%	2%	0%	0%
KS	Goodland	GLD	0%	0%	0%	0%	5%	19%	37%	28%	9%	1%	0%	0%
KS	Russell	RSL	0%	0%	0%	1%	7%	21%	33%	26%	10%	2%	0%	0%
KS	Salina	SLN	0%	0%	0%	2%	8%	21%	31%	26%	10%	2%	0%	0%
KS	Topeka	TOP	0%	0%	1%	2%	8%	21%	30%	27%	9%	2%	0%	0%
KS	Wichita	ICT	0%	0%	0%	2%	8%	20%	29%	26%	11%	2%	0%	0%
KY	Bowling Green	BWG	0%	0%	1%	3%	9%	20%	27%	26%	12%	2%	0%	0%
KY	Jackson	JKL	0%	0%	1%	4%	9%	19%	26%	26%	12%	3%	0%	0%
KY	Lexington	LEX	0%	0%	1%	2%	8%	20%	28%	27%	12%	2%	0%	0%
KY	Louisville	SDF	0%	0%	1%	3%	9%	20%	26%	26%	13%	3%	0%	0%
KY	Paducah	PAH	0%	0%	1%	2%	9%	21%	28%	26%	11%	2%	0%	0%
LA	Baton Rouge	BTR	1%	1%	3%	5%	12%	17%	19%	20%	14%	6%	2%	1%
LA	Lafayette	LFT	1%	1%	3%	6%	12%	17%	18%	19%	14%	7%	2%	1%
LA	Lake Charles	LCH	0%	1%	2%	5%	12%	17%	19%	19%	14%	7%	2%	1%
LA	Monroe	MLU	0%	0%	2%	4%	11%	18%	21%	22%	14%	5%	1%	0%
LA	New Orleans	MSY	1%	1%	3%	6%	12%	17%	18%	18%	15%	8%	2%	1%
LA	Shreveport	SHV	0%	0%	2%	4%	11%	18%	21%	22%	14%	5%	1%	0%
MA	Boston	BOS	0%	0%	0%	1%	4%	16%	36%	31%	11%	1%	0%	0%
MA	Worcester	ORH	0%	0%	0%	1%	5%	17%	37%	31%	9%	1%	0%	0%
MD	Baltimore	BWI	0%	0%	0%	1%	7%	20%	31%	27%	11%	2%	0%	0%

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MD	Salisbury	SBY	0%	0%	0%	2%	7%	18%	31%	27%	12%	2%	0%	0%
ME	Augusta	AUG	0%	0%	0%	0%	3%	15%	42%	33%	7%	1%	0%	0%
ME	Bangor	BGR	0%	0%	0%	0%	2%	15%	44%	33%	7%	0%	0%	0%
ME	Caribou	CAR	0%	0%	0%	0%	2%	18%	44%	30%	4%	0%	0%	0%
ME	Houlton	HUL	0%	0%	0%	0%	3%	17%	42%	32%	7%	0%	0%	0%
ME	Portland	PWM	0%	0%	0%	0%	2%	14%	42%	34%	8%	0%	0%	0%
MI	Alpena	APN	0%	0%	0%	0%	4%	18%	39%	29%	7%	2%	0%	0%
MI	Detroit	DTW	0%	0%	0%	1%	6%	20%	34%	28%	10%	1%	0%	0%
MI	Flint	FNT	0%	0%	0%	1%	6%	21%	35%	27%	9%	1%	0%	0%
MI	Grand Rapids	GRR	0%	0%	0%	1%	6%	20%	35%	27%	9%	1%	0%	0%
MI	Houghton Lake	HTL	0%	0%	0%	0%	6%	20%	38%	27%	7%	1%	0%	0%
MI	Jackson	JXN	0%	0%	0%	1%	6%	20%	35%	27%	9%	1%	0%	0%
MI	Lansing	LAN	0%	0%	0%	1%	6%	20%	36%	27%	9%	1%	0%	0%
MI	Marquette	MQT	0%	0%	0%	0%	4%	18%	41%	27%	9%	1%	0%	0%
MI	Muskegon	MKG	0%	0%	0%	0%	5%	18%	35%	29%	10%	1%	0%	0%
MI	Saginaw	MBS	0%	0%	0%	0%	6%	21%	35%	26%	8%	2%	0%	0%
MI	Sault St Marie	SSM	0%	0%	0%	0%	4%	14%	41%	31%	8%	1%	0%	0%
MI	Traverse City	TVC	0%	0%	1%	0%	5%	18%	36%	29%	10%	2%	0%	0%
MN	Alexandria	AXN	0%	0%	0%	0%	4%	16%	43%	27%	8%	1%	0%	0%
MN	Duluth	DLH	0%	0%	0%	0%	2%	11%	48%	29%	9%	0%	0%	0%
MN	Hibbing	HIB	0%	0%	0%	0%	5%	12%	46%	29%	7%	0%	0%	0%
MN	Int'l Falls	INL	0%	0%	0%	0%	3%	15%	44%	28%	8%	1%	0%	0%
MN	Minneapolis	MSP	0%	0%	0%	1%	5%	19%	38%	26%	10%	2%	0%	0%
MN	Rochester	RST	0%	0%	0%	1%	6%	22%	37%	24%	9%	2%	0%	0%
MN	Saint Cloud	STC	0%	0%	0%	0%	5%	18%	41%	25%	8%	1%	0%	0%
MO	Columbia	COU	0%	0%	1%	2%	8%	20%	30%	27%	10%	2%	0%	0%
MO	Joplin	JLN	0%	0%	1%	3%	8%	19%	27%	27%	11%	3%	0%	0%
MO	Kansas City	MCI	0%	0%	1%	2%	8%	20%	30%	28%	10%	2%	0%	0%
MO	Saint Louis	STL	0%	0%	1%	3%	9%	20%	28%	26%	11%	2%	0%	0%
MO	Springfield	SGF	0%	0%	1%	2%	8%	20%	29%	28%	10%	2%	0%	0%
MS	Greenwood	GWO	0%	0%	2%	4%	11%	19%	22%	23%	13%	4%	1%	0%
MS	McComb	MCB	0%	0%	2%	4%	11%	18%	21%	21%	15%	6%	1%	0%
MS	Tupelo	TUP	0%	0%	1%	3%	11%	19%	24%	24%	13%	4%	0%	0%
MT	Billings	BIL	0%	0%	0%	0%	2%	11%	44%	33%	8%	1%	0%	0%
MT	Butte	BTM	0%	0%	0%	0%	1%	8%	61%	30%	1%	0%	0%	0%
MT	Cut Bank	CTB	0%	0%	0%	0%	2%	6%	52%	34%	6%	0%	0%	0%
MT	Great Falls	GTF	0%	0%	0%	0%	1%	7%	49%	34%	8%	0%	0%	0%
MT	Havre	HVR	0%	0%	0%	0%	3%	8%	50%	33%	5%	0%	0%	0%
MT	Helena	HLN	0%	0%	0%	0%	2%	10%	49%	33%	6%	0%	0%	0%
MT	Kalispell	FCA	0%	0%	0%	1%	4%	12%	37%	34%	10%	2%	0%	0%
MT	Lewistown	LWT	0%	0%	0%	0%	1%	7%	51%	35%	7%	0%	0%	0%
MT	Miles City	MLS	0%	0%	0%	0%	2%	13%	44%	32%	8%	1%	0%	0%
MT	Missoula	MSO	0%	0%	0%	0%	1%	9%	51%	34%	4%	0%	0%	0%
NC	Asheville	AVL	0%	0%	0%	1%	7%	21%	31%	30%	10%	1%	0%	0%
NC	Cape Hatteras	HAT	1%	1%	2%	5%	9%	16%	19%	19%	15%	9%	3%	1%
NC	Charlotte	CLT	0%	0%	1%	2%	9%	20%	26%	25%	14%	2%	0%	0%
NC	Greensboro	GSO	0%	0%	1%	2%	9%	20%	27%	26%	13%	2%	0%	0%
NC	Hickory	HKY	0%	0%	1%	2%	9%	21%	27%	26%	12%	2%	0%	0%
NC	New Bern	EWN	0%	0%	1%	3%	9%	19%	25%	24%	14%	4%	1%	0%

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC	Raleigh Durham	RDU	0%	0%	1%	3%	9%	20%	26%	25%	13%	3%	0%	0%
NC	Wilmington	ILM	0%	0%	1%	3%	10%	19%	24%	23%	14%	5%	1%	0%
ND	Bismarck	BIS	0%	0%	0%	0%	2%	14%	45%	31%	8%	0%	0%	0%
ND	Devil's Lake	P11	0%	0%	0%	0%	2%	15%	44%	30%	8%	1%	0%	0%
ND	Fargo	FAR	0%	0%	0%	0%	4%	18%	40%	26%	9%	2%	0%	0%
ND	Grand Forks	GFK	0%	0%	0%	0%	3%	16%	44%	28%	9%	1%	0%	0%
ND	Minot	MOT	0%	0%	0%	0%	1%	14%	44%	32%	8%	0%	0%	0%
ND	Williston	ISN	0%	0%	0%	0%	2%	10%	48%	33%	7%	0%	0%	0%
NE	Grand Island	GRI	0%	0%	0%	1%	7%	20%	35%	27%	9%	2%	0%	0%
NE	Lincoln	LNK	0%	0%	0%	1%	7%	20%	34%	27%	8%	2%	0%	0%
NE	Norfolk	OFK	0%	0%	0%	2%	7%	19%	35%	27%	8%	2%	0%	0%
NE	North Platte	LBF	0%	0%	0%	0%	4%	18%	40%	29%	8%	1%	0%	0%
NE	Omaha	OMA	0%	0%	0%	2%	7%	20%	34%	27%	9%	2%	0%	0%
NE	Scottsbluff	BFF	0%	0%	0%	0%	3%	17%	42%	30%	7%	0%	0%	0%
NE	Valentine	VTN	0%	0%	0%	0%	4%	16%	40%	30%	9%	1%	0%	0%
NH	Concord	CON	0%	0%	0%	0%	4%	18%	39%	31%	8%	0%	0%	0%
NH	Lebanon	LEB	0%	0%	0%	0%	5%	19%	37%	31%	8%	1%	0%	0%
NJ	Atlantic City	ACY	0%	0%	0%	1%	6%	19%	32%	28%	12%	2%	0%	0%
NJ	Newark	EWR	0%	0%	0%	1%	5%	19%	32%	28%	12%	2%	0%	0%
NM	Albuquerque	ABQ	0%	0%	0%	1%	8%	23%	31%	25%	12%	1%	0%	0%
NM	Carlsbad	CNM	0%	0%	1%	4%	12%	22%	23%	22%	12%	3%	0%	0%
NM	Clayton	CAO	0%	0%	0%	1%	6%	21%	33%	27%	10%	2%	0%	0%
NM	Gallup	GUP	0%	0%	0%	0%	1%	15%	47%	32%	5%	0%	0%	0%
NM	Roswell	ROW	0%	0%	0%	3%	11%	23%	25%	23%	12%	3%	0%	0%
NV	Elko	EKO	0%	0%	0%	0%	2%	11%	49%	34%	4%	0%	0%	0%
NV	Ely	ELY	0%	0%	0%	0%	1%	9%	54%	34%	3%	0%	0%	0%
NV	Las Vegas	LAS	0%	0%	1%	3%	11%	18%	24%	22%	15%	5%	0%	0%
NV	Lovelock	LOL	0%	0%	0%	0%	5%	16%	40%	29%	8%	1%	0%	0%
NV	Reno	RNO	0%	0%	0%	0%	4%	16%	38%	30%	11%	1%	0%	0%
NV	Tonopah	TPH	0%	0%	0%	0%	4%	17%	38%	30%	11%	1%	0%	0%
NV	Winnemucca	WMC	0%	0%	0%	0%	3%	13%	48%	31%	5%	0%	0%	0%
NY	Albany	ALB	0%	0%	0%	1%	5%	19%	36%	29%	8%	1%	0%	0%
NY	Binghamton	BGM	0%	0%	0%	1%	6%	19%	36%	28%	8%	1%	0%	0%
NY	Buffalo	BUF	0%	0%	0%	0%	5%	18%	35%	30%	10%	1%	0%	0%
NY	Glens Falls	GFL	0%	0%	0%	0%	5%	19%	38%	31%	7%	0%	0%	0%
NY	Massena	MSS	0%	0%	0%	0%	4%	18%	41%	29%	8%	0%	0%	0%
NY	New York	LGA	0%	0%	0%	1%	5%	18%	31%	29%	14%	2%	0%	0%
NY	Rochester	ROC	0%	0%	0%	1%	6%	20%	36%	28%	9%	1%	0%	0%
NY	Syracuse	SYR	0%	0%	0%	1%	6%	19%	36%	29%	9%	1%	0%	0%
NY	Utica	UCA	0%	0%	0%	2%	10%	20%	29%	25%	11%	2%	0%	0%
NY	Watertown	ART	0%	0%	0%	0%	5%	17%	34%	33%	10%	1%	0%	0%
OH	Akron Canton	CAK	0%	0%	0%	1%	7%	20%	33%	28%	9%	1%	0%	0%
OH	Cincinnati	CVG	0%	0%	1%	1%	7%	19%	29%	28%	12%	2%	0%	0%
OH	Cleveland	CLE	0%	0%	0%	1%	7%	20%	33%	27%	10%	1%	0%	0%
OH	Columbus	CMH	0%	0%	0%	1%	8%	20%	30%	28%	11%	2%	0%	0%
OH	Dayton	DAY	0%	0%	0%	1%	8%	20%	31%	27%	10%	2%	0%	0%
OH	Findlay	FDY	0%	0%	0%	1%	8%	22%	32%	26%	10%	2%	0%	0%
OH	Mansfield	MFD	0%	0%	0%	1%	8%	20%	32%	28%	9%	1%	0%	0%
OH	Toledo	TOL	0%	0%	0%	1%	6%	21%	34%	27%	9%	1%	0%	0%

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
OH	Youngstown	YNG	0%	0%	0%	1%	7%	19%	35%	28%	9%	1%	0%	0%
OK	Hobart	HBR	0%	0%	1%	2%	10%	20%	26%	25%	13%	3%	0%	0%
OK	McAlester	MLC	0%	0%	1%	3%	9%	19%	25%	25%	13%	4%	1%	0%
OK	Oklahoma City	OKC	0%	0%	1%	3%	9%	19%	26%	25%	12%	3%	0%	0%
OK	Tulsa	TUL	0%	0%	1%	3%	9%	19%	27%	25%	12%	3%	0%	0%
OR	Astoria	AST	0%	0%	0%	0%	12%	10%	29%	24%	25%	0%	0%	0%
OR	Baker	BKE	0%	0%	0%	0%	2%	7%	53%	34%	3%	0%	0%	0%
OR	Eugene	EUG	0%	0%	0%	0%	2%	7%	41%	38%	12%	0%	0%	0%
OR	Medford	MFR	0%	0%	0%	0%	4%	11%	37%	33%	14%	1%	0%	0%
OR	Pendleton	PDT	0%	0%	0%	0%	3%	11%	42%	35%	9%	1%	0%	0%
OR	Portland	PDX	0%	0%	0%	0%	4%	11%	36%	35%	14%	0%	0%	0%
OR	Redmond	RDM	0%	0%	0%	0%	3%	8%	50%	33%	6%	0%	0%	0%
OR	Salem	SLE	0%	0%	0%	0%	3%	9%	39%	36%	12%	0%	0%	0%
PA	Allentown	ABE	0%	0%	0%	1%	6%	20%	34%	28%	10%	1%	0%	0%
PA	Altoona	AOO	0%	0%	0%	1%	7%	20%	34%	28%	8%	1%	0%	0%
PA	Bradford	BFD	0%	0%	0%	0%	6%	20%	38%	28%	8%	0%	0%	0%
PA	Du Bois	DUJ	0%	0%	0%	1%	7%	18%	34%	29%	8%	1%	0%	0%
PA	Erie	ERI	0%	0%	0%	1%	6%	19%	33%	29%	11%	2%	0%	0%
PA	Harrisburg	CXY	0%	0%	0%	1%	7%	20%	32%	28%	11%	1%	0%	0%
PA	Philadelphia	PHL	0%	0%	0%	1%	7%	19%	31%	27%	13%	2%	0%	0%
PA	Pittsburgh	PIT	0%	0%	0%	1%	7%	19%	33%	29%	10%	1%	0%	0%
PA	Williamsport	IPT	0%	0%	0%	1%	7%	20%	35%	28%	9%	1%	0%	0%
RI	Providence	PVD	0%	0%	0%	0%	3%	16%	36%	32%	11%	1%	0%	0%
SC	Charleston	CHS	0%	0%	1%	4%	11%	18%	22%	22%	15%	5%	1%	0%
SC	Columbia	CAE	0%	0%	1%	4%	11%	19%	23%	23%	14%	4%	1%	0%
SC	Florence	FLO	0%	0%	1%	3%	10%	19%	24%	23%	14%	4%	1%	0%
SC	Greenville	GSP	0%	0%	1%	2%	9%	21%	25%	25%	14%	3%	0%	0%
SD	Aberdeen	ABR	0%	0%	0%	0%	3%	18%	43%	27%	8%	1%	0%	0%
SD	Huron	HON	0%	0%	0%	1%	4%	17%	41%	28%	9%	1%	0%	0%
SD	Pierre	PIR	0%	0%	0%	0%	3%	15%	41%	31%	9%	1%	0%	0%
SD	Rapid City	RAP	0%	0%	0%	0%	2%	13%	43%	32%	8%	1%	0%	0%
SD	Sioux Falls	FSD	0%	0%	0%	1%	5%	18%	39%	27%	9%	1%	0%	0%
TN	Bristol	TRI	0%	0%	0%	1%	7%	21%	29%	29%	12%	1%	0%	0%
TN	Chattanooga	CHA	0%	0%	1%	3%	10%	20%	25%	26%	13%	3%	0%	0%
TN	Crossville	CSV	0%	0%	0%	2%	8%	20%	28%	28%	11%	1%	0%	0%
TN	Jackson	MKL	0%	0%	1%	3%	10%	20%	25%	25%	12%	3%	0%	0%
TN	Knoxville	TYS	0%	0%	1%	2%	9%	20%	26%	26%	13%	2%	0%	0%
TN	Memphis	MEM	0%	0%	1%	4%	11%	20%	23%	23%	14%	4%	0%	0%
TN	Nashville	BNA	0%	0%	1%	3%	9%	20%	26%	26%	13%	3%	0%	0%
TX	Abilene	ABI	0%	0%	2%	5%	11%	19%	22%	22%	13%	5%	1%	0%
TX	Alice	ALI	1%	2%	4%	7%	12%	15%	16%	17%	13%	8%	4%	2%
TX	Amarillo	AMA	0%	0%	0%	2%	9%	22%	28%	26%	11%	2%	0%	0%
TX	Austin	AUS	0%	1%	2%	5%	12%	17%	19%	21%	14%	6%	2%	0%
TX	Brownsville	BRO	2%	2%	5%	8%	12%	14%	15%	15%	12%	9%	5%	2%
TX	College Station	CLL	0%	1%	3%	6%	12%	17%	19%	20%	14%	7%	2%	1%
TX	Corpus Christi	CRP	1%	2%	4%	7%	12%	14%	16%	17%	13%	9%	4%	1%
TX	Dallas-Ft. Worth	DFW	0%	0%	2%	4%	11%	18%	22%	22%	14%	6%	1%	0%
TX	Del Rio	DRT	0%	1%	3%	7%	12%	17%	18%	19%	13%	7%	2%	0%
TX	El Paso	ELP	0%	0%	1%	4%	13%	22%	22%	21%	13%	4%	0%	0%

Station Location		Code	Monthly Cooling Degree Day Fractions											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
TX	Galveston	GLS	0%	0%	2%	6%	11%	15%	17%	18%	15%	10%	4%	1%
TX	Houston	IAH	1%	1%	3%	6%	12%	17%	18%	19%	14%	7%	2%	1%
TX	Laredo	LRD	1%	2%	5%	9%	13%	15%	15%	16%	12%	8%	4%	1%
TX	Lubbock	LBB	0%	0%	1%	3%	11%	22%	25%	24%	11%	3%	0%	0%
TX	Lufkin	LFK	0%	1%	2%	5%	12%	17%	20%	21%	14%	6%	2%	0%
TX	McAllen	MFE	2%	2%	5%	8%	12%	14%	14%	15%	12%	9%	4%	2%
TX	Midland Odessa	MAF	0%	0%	1%	5%	12%	21%	22%	22%	12%	4%	0%	0%
TX	San Angelo	SJT	0%	0%	2%	5%	12%	19%	21%	21%	12%	5%	1%	0%
TX	San Antonio	SAT	0%	1%	3%	6%	12%	17%	18%	20%	14%	7%	2%	0%
TX	Victoria	VCT	1%	1%	3%	6%	12%	16%	17%	19%	14%	8%	3%	1%
TX	Waco	ACT	0%	0%	2%	5%	11%	18%	21%	22%	14%	6%	2%	0%
TX	Wichita Falls	SPS	0%	0%	1%	4%	10%	19%	24%	24%	13%	4%	1%	0%
UT	Cedar City	CDC	0%	0%	0%	0%	2%	16%	44%	32%	6%	0%	0%	0%
UT	Salt Lake City	SLC	0%	0%	0%	0%	4%	15%	38%	31%	10%	1%	0%	0%
VA	Lynchburg	LYH	0%	0%	0%	2%	7%	19%	30%	29%	11%	1%	0%	0%
VA	Norfolk	ORF	0%	0%	1%	3%	8%	19%	27%	25%	14%	4%	0%	0%
VA	Richmond	RIC	0%	0%	0%	3%	8%	20%	28%	25%	13%	3%	0%	0%
VA	Roanoke	ROA	0%	0%	1%	2%	8%	20%	28%	27%	11%	2%	0%	0%
VT	Burlington	BTV	0%	0%	0%	1%	4%	19%	37%	30%	8%	0%	0%	0%
VT	Montpelier	MPV	0%	0%	0%	0%	4%	19%	38%	32%	7%	0%	0%	0%
WA	Bellingham	BLI	0%	0%	0%	0%	1%	8%	49%	38%	4%	0%	0%	0%
WA	Olympia	OLM	0%	0%	0%	0%	2%	10%	46%	36%	5%	0%	0%	0%
WA	Quillayute	UIL	0%	0%	0%	0%	5%	14%	36%	35%	10%	0%	0%	0%
WA	Seattle Tacoma	SEA	0%	0%	0%	0%	3%	12%	40%	35%	11%	0%	0%	0%
WA	Spokane	GEG	0%	0%	0%	0%	3%	9%	44%	35%	8%	0%	0%	0%
WA	Walla Walla	ALW	0%	0%	0%	0%	4%	12%	39%	34%	11%	1%	0%	0%
WA	Yakima	YKM	0%	0%	0%	0%	4%	13%	43%	33%	7%	0%	0%	0%
WI	Eau Claire	EAU	0%	0%	0%	0%	5%	19%	39%	26%	9%	2%	0%	0%
WI	Green Bay	GRB	0%	0%	0%	0%	5%	20%	38%	27%	9%	1%	0%	0%
WI	Lacrosse	LSE	0%	0%	0%	1%	5%	20%	36%	26%	9%	2%	0%	0%
WI	Madison	MSN	0%	0%	0%	0%	5%	20%	36%	27%	9%	1%	0%	0%
WI	Milwaukee	MKE	0%	0%	0%	0%	4%	18%	35%	31%	11%	2%	0%	0%
WI	Wausau	AUW	0%	0%	0%	0%	5%	19%	40%	27%	8%	1%	0%	0%
WV	Beckley	BKW	0%	0%	0%	2%	7%	18%	31%	30%	10%	1%	0%	0%
WV	Charleston	CRW	0%	0%	1%	2%	8%	19%	28%	28%	12%	2%	0%	0%
WV	Elkins	EKN	0%	0%	0%	0%	5%	18%	34%	34%	8%	1%	0%	0%
WV	Huntington	HTS	0%	0%	1%	2%	8%	20%	28%	28%	12%	2%	0%	0%
WV	Martinsburg	MRB	0%	0%	0%	1%	7%	20%	32%	28%	10%	1%	0%	0%
WV	Morgantown	MGW	0%	0%	0%	2%	8%	18%	30%	28%	11%	2%	0%	0%
WV	Parkersburg	PKB	0%	0%	0%	2%	8%	19%	30%	29%	11%	2%	0%	0%
WY	Casper	CPR	0%	0%	0%	0%	1%	11%	49%	33%	5%	0%	0%	0%
WY	Cheyenne	CYS	0%	0%	0%	0%	1%	13%	48%	33%	5%	0%	0%	0%
WY	Cody	COD	0%	0%	0%	0%	2%	11%	46%	32%	7%	1%	0%	0%
WY	Lander	LND	0%	0%	0%	0%	2%	12%	47%	34%	5%	0%	0%	0%
WY	Rock Springs	RKS	0%	0%	0%	0%	1%	12%	53%	33%	2%	0%	0%	0%
WY	Sheridan	SHR	0%	0%	0%	0%	1%	10%	47%	36%	6%	0%	0%	0%
WY	Worland	WRL	0%	0%	0%	0%	2%	14%	45%	32%	5%	1%	0%	0%

7C.3.2 Monthly Average Outdoor Temperature Data by Weather Station

Table 7C.3.6 shows for each weather station the 30-year (1970-2000) monthly average outdoor temperature data based on NOAA data.[5] Average monthly outdoor temperature where used to determine hours of operation of heat tape in condensate withdrawal systems that require it for high efficiency furnaces as described in appendix 7B and appendix 8D.

Table 7C.3.6 Weather Station Monthly Average Outdoor Temperature (1970-2000)

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AK	Anchorage	ANC	16	19	26	36	47	55	58	56	48	34	22	18
AK	Bethel	BET	7	8	15	26	41	51	56	54	45	30	17	9
AK	Cold Bay	CDB	28	28	30	34	40	46	51	52	48	40	35	31
AK	Cordova	CDV	28	28	30	34	40	46	51	52	48	40	35	31
AK	Homer	HOM	23	25	29	36	44	50	54	54	48	38	29	26
AK	Juneau	JNU	26	29	34	41	48	54	57	56	50	42	33	29
AK	Kenai	ENA	16	19	26	36	47	55	58	56	48	34	22	18
AK	Ketchikan	KTN	22	25	30	38	46	52	55	54	47	38	28	25
AK	King Salmon	AKN	15	16	24	33	44	51	56	55	48	33	23	17
AK	Kodiak	ADQ	30	30	33	37	44	49	54	55	49	40	34	31
AK	Sitka	SIT	26	29	34	41	48	54	57	56	50	42	33	29
AK	St Paul Island	SNP	26	23	24	28	36	42	47	48	45	38	33	29
AK	Talkeetna	TKA	11	15	23	34	46	55	59	56	46	31	18	13
AK	Valdez	VWS	22	25	30	38	46	52	55	54	47	38	28	25
AK	Yakutat	YAK	26	28	32	37	44	50	54	53	48	41	32	29
AL	Birmingham	BHM	43	47	55	61	69	76	80	80	74	63	53	46
AL	Huntsville	HSV	40	44	52	60	69	76	80	79	72	61	51	43
AL	Mobile	MOB	50	54	60	66	74	79	82	81	77	68	59	52
AL	Montgomery	MGM	47	51	58	64	72	79	82	81	76	65	56	49
AL	Muscle Shoals	MSL	40	45	53	61	69	76	80	79	73	62	51	43
AL	Tuscaloosa	TCL	45	49	57	63	72	79	82	81	75	64	54	47
AR	Fayetteville	FYV	35	41	49	58	65	74	79	78	70	59	48	39
AR	Fort Smith	FSM	38	44	53	61	70	78	82	82	74	63	51	41
AR	Little Rock	LIT	40	45	53	61	70	78	82	81	74	63	52	43
AR	Texarkana	TXK	38	44	53	61	70	78	82	82	74	63	51	41
AZ	Douglas	DUG	45	49	54	59	68	76	79	77	73	62	51	45
AZ	Flagstaff	FLG	30	32	37	43	51	60	66	64	58	47	37	30
AZ	Phoenix	PHX	56	60	65	71	81	90	95	93	87	75	63	56
AZ	Tucson	TUS	52	55	59	66	75	84	87	85	81	71	59	52
AZ	Winslow	INW	34	40	46	53	62	72	78	76	68	56	43	34
AZ	Yuma	NYL	58	62	67	73	80	89	94	94	88	77	65	57
CA	Bakersfield	BFL	48	53	57	63	70	78	83	82	77	67	55	47
CA	Blythe	BLH	53	57	63	70	78	86	92	91	84	72	59	52
CA	Eureka	EKA	48	49	49	51	54	56	58	59	57	55	51	48
CA	Fresno	FAT	46	51	56	61	69	76	81	80	75	65	53	45
CA	Los Angeles	LAX	57	58	58	61	63	66	69	71	70	67	62	58
CA	Mt Shasta	MHS	35	38	41	46	53	60	66	65	60	51	40	35
CA	Paso Robles	PRB	48	51	53	56	61	66	70	70	67	61	51	46
CA	Red Bluff	RBL	46	49	53	58	66	75	81	79	73	63	51	45
CA	Redding	RDD	46	49	53	58	66	75	81	79	73	63	51	45

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CA	Sacramento	SAC	46	51	55	59	66	72	75	75	72	64	53	46
CA	San Diego	SAN	58	59	60	63	65	67	71	73	72	68	62	58
CA	San Francisco	SFO	49	52	54	56	59	61	63	64	64	61	55	50
CA	Stockton	SCK	46	51	55	60	67	73	77	77	73	65	53	45
CO	Alamosa	ALS	15	23	33	41	50	59	64	62	55	43	28	17
CO	Colorado Spring	COS	28	32	38	45	55	64	70	68	60	49	36	29
CO	Denver	DEN	29	33	40	48	57	68	73	72	62	51	38	30
CO	Eagle	EGE	15	23	33	41	50	59	64	62	55	43	28	17
CO	Pueblo	PUB	29	35	42	50	60	70	75	74	65	52	38	30
CO	Trinidad	TAD	33	36	42	49	58	67	71	69	62	52	40	33
CT	Bridgeport	BDR	30	32	40	49	59	68	74	73	66	55	45	35
CT	Hartford	BDL	26	29	38	49	60	69	74	72	63	52	42	31
DC	Washington	DCA	35	38	47	56	66	75	79	77	71	59	49	40
DE	Wilmington	ILG	32	34	43	52	63	72	77	75	68	56	46	36
FL	Daytona Beach	DAB	58	60	65	69	75	80	82	82	80	74	67	61
FL	Fort Myers	FMY	65	66	70	74	79	82	83	83	82	78	72	66
FL	Ft Lauderdale	FLL	67	68	71	74	78	81	82	83	82	78	74	69
FL	Gainesville	GNV	54	57	63	68	74	79	81	80	78	70	63	56
FL	Jacksonville	JAX	53	56	62	67	73	79	82	81	78	69	62	55
FL	Key West	EYW	70	71	74	77	81	83	85	84	83	80	76	72
FL	Melbourne	MLB	63	64	68	72	76	80	82	82	81	76	71	65
FL	Miami	MIA	68	69	72	76	80	82	84	84	82	79	74	70
FL	Orlando	MCO	61	63	67	72	77	81	82	83	81	75	69	63
FL	Pensacola	PNS	52	55	61	67	75	81	83	82	79	70	61	54
FL	Tallahassee	TLH	52	55	61	66	74	80	82	82	79	69	60	54
FL	Tampa	TPA	61	63	67	72	78	82	83	83	82	76	69	63
FL	Vero Beach	VRB	63	64	68	72	76	80	82	82	81	76	71	65
FL	West Palm Beach	PBI	66	67	71	74	78	81	83	83	82	78	73	68
GA	Albany	ABY	48	52	60	65	73	79	82	81	77	67	58	51
GA	Athens	AHN	42	46	54	61	69	76	80	78	73	62	53	45
GA	Atlanta	ATL	43	47	54	62	70	77	80	79	73	63	53	45
GA	Augusta	AGS	45	48	56	62	71	78	81	79	74	63	54	47
GA	Brunswick	SSI	53	56	62	67	75	80	83	82	78	70	62	55
GA	Columbus	CSG	47	50	58	64	72	79	82	81	76	66	57	49
GA	Macon	MCN	46	49	56	63	71	78	81	80	75	64	55	48
GA	Savannah	SAV	49	53	59	65	73	79	82	81	77	67	59	51
GA	Waycross	AYS	50	53	60	66	73	79	82	81	77	67	60	52
HI	Hilo-Hawaii	ITO	71	72	72	73	74	75	76	76	76	76	74	72
HI	Honolulu-Oahu	HNL	73	73	74	76	77	80	81	82	82	80	78	75
HI	Kahului-Maui	OGG	72	72	73	74	76	78	79	80	79	78	76	73
HI	Lihue-Kauai	LIH	72	72	73	74	75	78	79	80	80	78	76	73
IA	Burlington	BRL	20	27	38	51	62	71	76	74	65	53	38	25
IA	Cedar Rapids	CID	16	23	35	48	60	70	74	71	63	50	35	22
IA	Des Moines	DSM	20	27	38	51	62	71	76	74	65	53	38	25
IA	Dubuque	DBQ	17	23	35	48	59	68	72	70	62	50	36	23
IA	Mason City	MCW	16	23	35	48	60	70	74	71	63	50	35	22
IA	Ottumwa	OTM	20	27	38	51	62	71	76	74	65	53	38	25
IA	Sioux City	SUX	19	25	37	50	61	71	75	72	63	51	35	22
IA	Waterloo	ALO	16	23	35	48	60	70	74	71	63	50	35	22

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ID	Boise	BOI	30	37	44	51	59	67	75	74	64	53	40	31
ID	Burley	BYI	24	30	38	46	54	62	69	68	59	48	35	25
ID	Idaho Falls	IDA	24	30	38	46	54	62	69	68	59	48	35	25
ID	Lewiston	LWS	34	38	45	51	59	66	74	73	64	52	40	34
ID	Pocatello	PIH	24	30	38	46	54	62	69	68	59	48	35	25
IL	Chicago	ORD	22	27	37	48	59	68	73	72	64	52	39	27
IL	Moline	MLI	21	27	39	51	62	71	75	73	65	53	39	26
IL	Peoria	PIA	23	28	40	51	62	71	75	73	65	53	40	28
IL	Quincy	UIN	23	28	40	51	62	71	75	73	65	53	40	28
IL	Rockford	RFD	19	25	36	48	60	69	73	71	63	51	37	24
IL	Springfield	SPI	25	31	42	53	64	73	76	74	67	56	42	30
IN	Evansville	EVV	31	36	46	56	66	75	79	77	69	57	46	36
IN	Fort Wayne	FWA	24	27	38	49	60	70	73	71	64	52	41	29
IN	Indianapolis	IND	27	31	42	52	63	72	75	74	66	55	43	32
IN	South Bend	SBN	23	27	38	48	60	69	73	71	63	52	40	29
IN	West Lafayette	LAF	0	0	0	0	0	0	0	0	0	0	0	0
KS	Concordia	CNK	27	32	43	53	63	73	79	77	68	56	41	30
KS	Dodge City	DDC	30	36	44	54	64	74	80	78	69	57	42	33
KS	Garden City	GCK	30	36	44	54	64	74	80	78	69	57	42	33
KS	Goodland	GLD	28	32	40	49	59	70	75	73	64	52	37	30
KS	Russell	RSL	27	32	43	53	63	73	79	77	68	56	41	30
KS	Salina	SLN	30	36	46	55	65	76	81	80	71	59	44	34
KS	Topeka	TOP	27	33	44	55	64	74	78	77	68	57	43	31
KS	Wichita	ICT	30	36	46	55	65	76	81	80	71	59	44	34
KY	Bowling Green	BWG	34	39	48	57	66	74	79	77	70	58	47	38
KY	Jackson	JKL	34	38	47	56	64	71	75	74	68	58	48	38
KY	Lexington	LEX	32	36	46	55	64	72	76	75	68	57	46	36
KY	Louisville	SDF	33	38	47	56	66	74	78	77	70	59	48	38
KY	Paducah	PAH	33	38	48	57	66	75	78	76	69	58	47	37
LA	Baton Rouge	BTR	50	54	60	67	74	80	82	81	78	68	59	52
LA	Lafayette	LFT	52	55	62	68	75	81	83	82	78	69	60	54
LA	Lake Charles	LCH	51	54	61	67	75	81	83	82	78	70	60	53
LA	Monroe	MLU	46	51	59	65	73	80	83	83	77	67	56	48
LA	New Orleans	MSY	53	56	62	68	76	81	83	83	79	70	61	55
LA	Shreveport	SHV	46	51	59	65	73	80	83	83	77	67	56	48
MA	Boston	BOS	29	32	39	48	59	68	74	72	65	54	45	35
MA	Worcester	ORH	24	26	34	45	56	65	70	68	60	50	40	29
MD	Baltimore	BWI	32	36	44	53	63	72	77	75	67	55	46	37
MD	Salisbury	SBY	36	38	46	55	64	72	77	75	69	58	49	40
ME	Augusta	AUG	22	25	34	44	54	63	69	67	59	48	38	28
ME	Bangor	BGR	22	25	34	44	54	63	69	67	59	48	38	28
ME	Caribou	CAR	10	13	25	38	52	61	66	63	54	43	31	16
ME	Houlton	HUL	11	14	26	39	52	61	66	64	55	43	31	17
ME	Portland	PWM	22	25	34	44	54	63	69	67	59	48	38	28
MI	Alpena	APN	18	19	28	40	52	61	67	65	56	46	35	24
MI	Detroit	DTW	25	27	37	48	60	69	74	72	64	52	41	30
MI	Flint	FNT	21	24	34	45	57	66	71	69	61	49	38	27
MI	Grand Rapids	GRR	22	25	35	46	58	67	71	69	61	50	38	28
MI	Houghton Lake	HTL	18	20	29	42	54	62	67	65	57	46	35	24

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MI	Jackson	JXN	24	25	34	45	56	65	70	69	61	50	39	29
MI	Lansing	LAN	22	24	34	46	57	66	70	68	61	49	38	27
MI	Marquette	MQT	12	15	24	36	50	59	64	62	54	43	29	17
MI	Muskegon	MKG	24	25	34	45	56	65	70	69	61	50	39	29
MI	Saginaw	MBS	24	25	34	45	56	65	70	69	61	50	39	29
MI	Sault St Marie	SSM	13	16	25	38	51	59	64	63	55	44	32	20
MI	Traverse City	TVC	24	25	34	45	56	65	70	69	61	50	39	29
MN	Alexandria	AXN	9	16	28	44	57	65	70	67	57	45	29	14
MN	Duluth	DLH	8	15	25	39	52	60	66	64	55	44	28	14
MN	Hibbing	HIB	3	11	24	39	53	62	66	64	53	42	24	9
MN	Int'l Falls	INL	3	11	24	39	53	62	66	64	53	42	24	9
MN	Minneapolis	MSP	13	20	32	47	59	68	73	71	61	49	33	19
MN	Rochester	RST	12	18	31	45	57	66	70	68	59	47	31	17
MN	Saint Cloud	STC	9	16	28	44	57	65	70	67	57	45	29	14
MO	Columbia	COU	28	34	44	54	64	73	77	76	67	56	43	32
MO	Joplin	JLN	32	37	46	56	65	73	79	78	69	58	46	36
MO	Kansas City	MCI	27	33	44	54	64	74	79	77	68	57	43	31
MO	Saint Louis	STL	30	35	46	57	67	76	80	78	70	58	45	34
MO	Springfield	SGF	32	37	46	56	65	73	79	78	69	58	46	36
MS	Greenwood	GWO	40	45	53	61	69	77	81	80	73	62	52	43
MS	McComb	MCB	45	49	57	63	72	79	81	81	76	64	55	48
MS	Tupelo	TUP	40	45	53	61	69	77	81	80	73	62	52	43
MT	Billings	BIL	24	30	37	46	56	65	72	71	60	48	34	26
MT	Butte	BTM	17	22	30	40	49	57	62	62	51	41	27	20
MT	Cut Bank	CTB	17	22	30	40	49	57	62	62	51	41	27	20
MT	Great Falls	GTF	22	26	33	43	52	60	66	66	55	46	32	24
MT	Havre	HVR	22	26	33	43	52	60	66	66	55	46	32	24
MT	Helena	HLN	20	26	35	44	53	61	68	67	56	45	31	21
MT	Kalispell	FCA	21	27	35	43	51	58	64	63	53	42	31	23
MT	Lewistown	LWT	22	26	33	43	52	60	66	66	55	46	32	24
MT	Miles City	MLS	17	25	35	47	57	67	74	73	60	48	32	21
MT	Missoula	MSO	24	29	38	45	53	60	67	66	56	44	32	23
NC	Asheville	AVL	36	39	46	54	62	69	73	72	66	55	46	39
NC	Cape Hatteras	HAT	46	47	52	60	68	75	79	79	75	66	58	50
NC	Charlotte	CLT	42	45	53	61	69	77	80	79	73	62	52	44
NC	Greensboro	GSO	38	41	49	58	66	74	78	76	70	59	49	41
NC	Hickory	HKY	38	41	49	58	66	74	78	76	70	59	49	41
NC	New Bern	EWN	46	49	55	63	70	77	81	80	75	65	57	49
NC	Raleigh Durham	RDU	40	43	51	59	67	75	79	77	71	60	51	43
NC	Wilmington	ILM	46	49	55	63	70	77	81	80	75	65	57	49
ND	Bismarck	BIS	10	18	30	43	56	65	70	69	58	45	28	15
ND	Devil's Lake	P11	5	13	26	42	57	65	69	68	57	44	26	11
ND	Fargo	FAR	7	14	27	44	57	66	71	69	58	45	27	13
ND	Grand Forks	GFK	5	13	26	42	57	65	69	68	57	44	26	11
ND	Minot	MOT	8	15	27	43	57	66	71	69	58	45	26	13
ND	Williston	ISN	8	17	29	43	55	64	69	68	56	44	26	13
NE	Grand Island	GRI	22	28	38	50	61	71	76	74	64	52	36	26
NE	Lincoln	LNK	22	28	39	51	62	73	78	75	66	54	38	27
NE	Norfolk	OFK	20	26	37	49	60	70	75	73	63	51	35	24

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NE	North Platte	LBF	23	29	38	48	58	68	74	73	62	50	35	26
NE	Omaha	OMA	22	28	39	51	62	72	77	75	65	53	38	26
NE	Scottsbluff	BFF	25	30	37	46	57	67	73	71	61	48	34	26
NE	Valentine	VTN	21	27	35	46	58	68	74	72	62	48	33	24
NH	Concord	CON	20	23	33	45	56	65	70	68	59	48	38	26
NH	Lebanon	LEB	20	23	33	45	56	65	70	68	59	48	38	26
NJ	Atlantic City	ACY	32	34	42	51	61	70	75	74	66	55	46	37
NJ	Newark	EWR	31	34	42	52	63	72	77	76	68	56	46	36
NM	Albuquerque	ABQ	36	41	48	56	65	75	79	76	69	57	44	36
NM	Carlsbad	CNM	43	49	56	63	72	79	81	80	73	63	51	44
NM	Clayton	CAO	34	38	44	52	61	70	74	72	65	55	42	35
NM	Gallup	GUP	34	38	44	52	61	70	74	72	65	55	42	35
NM	Roswell	ROW	40	46	53	61	70	78	81	79	72	61	49	41
NV	Elko	EKO	26	31	39	45	53	62	69	68	58	47	35	26
NV	Ely	ELY	25	30	36	42	50	60	67	66	57	45	34	26
NV	Las Vegas	LAS	47	52	58	66	75	86	91	89	81	69	55	47
NV	Lovelock	LOL	30	37	42	48	56	65	72	70	62	50	38	30
NV	Reno	RNO	34	39	43	49	56	65	71	70	62	52	41	34
NV	Tonopah	TPH	34	39	43	49	56	65	71	70	62	52	41	34
NV	Winnemucca	WMC	30	36	41	47	55	64	72	70	60	49	37	30
NY	Albany	ALB	22	25	35	47	58	66	71	69	61	49	39	28
NY	Binghamton	BGM	22	24	33	44	56	64	69	67	59	48	38	27
NY	Buffalo	BUF	25	26	34	45	57	66	71	69	62	51	40	30
NY	Glens Falls	GFL	19	21	31	44	56	65	70	68	60	48	38	26
NY	Massena	MSS	19	21	31	44	56	65	70	68	60	48	38	26
NY	New York	LGA	33	35	42	52	62	72	77	76	69	58	48	38
NY	Rochester	ROC	24	25	34	45	57	66	71	69	61	50	40	29
NY	Syracuse	SYR	23	25	34	45	57	66	71	69	61	50	40	29
NY	Utica	UCA	21	23	33	45	57	66	70	68	60	49	38	27
NY	Watertown	ART	19	21	31	44	56	65	70	68	60	48	38	26
OH	Akron Canton	CAK	25	28	38	48	59	68	72	70	63	52	41	31
OH	Cincinnati	CVG	30	34	44	54	64	72	76	75	67	56	45	35
OH	Cleveland	CLE	26	28	38	48	59	68	72	70	63	52	42	31
OH	Columbus	CMH	28	32	42	52	63	71	75	74	67	55	44	34
OH	Dayton	DAY	26	30	40	51	61	70	74	72	65	54	42	31
OH	Findlay	FDY	25	28	38	49	61	70	74	71	64	53	41	30
OH	Mansfield	MFD	24	27	37	47	58	67	71	69	63	52	41	30
OH	Toledo	TOL	24	27	37	48	60	69	73	71	64	52	41	29
OH	Youngstown	YNG	25	28	37	47	58	66	70	68	62	51	41	30
OK	Hobart	HBR	36	42	50	59	68	78	83	81	73	62	48	38
OK	McAlester	MLC	37	42	51	60	68	77	82	81	73	62	49	40
OK	Oklahoma City	OKC	37	42	51	60	68	77	82	81	73	62	49	40
OK	Tulsa	TUL	36	42	51	61	69	78	84	82	74	63	50	40
OR	Astoria	AST	42	44	46	49	53	57	60	61	59	53	47	43
OR	Baker	BKE	26	32	38	45	52	59	66	65	56	46	34	26
OR	Eugene	EUG	40	43	46	50	55	60	66	66	62	53	45	40
OR	Medford	MFR	39	44	47	52	58	66	73	73	66	55	44	38
OR	Pendleton	PDT	34	39	45	51	58	65	73	72	63	52	41	34
OR	Portland	PDX	40	43	47	51	57	63	68	69	64	54	46	40

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
OR	Redmond	RDM	24	30	37	43	51	58	66	64	55	44	33	25
OR	Salem	SLE	40	43	47	50	56	61	67	67	62	53	45	40
PA	Allentown	ABE	27	30	39	49	60	69	73	71	63	52	42	32
PA	Altoona	AOO	26	29	38	49	60	68	72	71	63	51	41	31
PA	Bradford	BFD	26	29	38	49	60	68	72	71	63	51	41	31
PA	Du Bois	DUJ	26	29	38	49	60	68	72	71	63	51	41	31
PA	Erie	ERI	27	28	37	47	58	67	72	71	64	53	43	33
PA	Harrisburg	CXY	30	33	42	52	62	71	76	74	66	55	44	35
PA	Philadelphia	PHL	32	35	43	53	64	72	78	76	69	57	47	37
PA	Pittsburgh	PIT	28	31	40	50	60	68	73	71	64	53	42	33
PA	Williamsport	IPT	26	29	38	49	60	68	72	71	63	51	41	31
RI	Providence	PVD	29	31	39	49	59	68	73	72	64	53	44	34
SC	Charleston	CHS	48	51	58	64	72	78	82	81	76	66	58	51
SC	Columbia	CAE	45	48	55	63	72	79	82	80	75	64	55	47
SC	Florence	FLO	45	48	55	63	72	79	82	80	75	64	55	47
SC	Greenville	GSP	41	44	52	59	67	75	79	78	71	61	51	44
SD	Aberdeen	ABR	11	19	31	45	58	67	72	71	60	47	29	16
SD	Huron	HON	14	21	33	46	58	68	73	72	61	48	31	19
SD	Pierre	PIR	18	24	35	47	59	69	76	74	64	50	34	22
SD	Rapid City	RAP	22	27	35	45	55	65	72	71	61	48	33	25
SD	Sioux Falls	FSD	14	21	33	46	58	68	73	71	61	48	31	18
TN	Bristol	TRI	34	38	47	55	63	71	74	73	67	55	46	37
TN	Chattanooga	CHA	39	43	51	60	68	75	80	79	72	60	50	42
TN	Crossville	CSV	33	38	46	54	63	69	73	72	66	55	46	37
TN	Jackson	MKL	37	42	51	59	68	76	79	78	72	60	50	41
TN	Knoxville	TYS	38	42	50	58	66	74	78	77	71	59	49	41
TN	Memphis	MEM	40	45	54	62	71	79	83	81	75	64	52	43
TN	Nashville	BNA	37	41	50	59	67	75	79	78	71	60	49	41
TX	Abilene	ABI	44	49	56	65	73	80	84	83	76	66	54	45
TX	Alice	ALI	56	60	67	73	78	83	85	85	81	74	66	58
TX	Amarillo	AMA	36	41	48	56	65	74	78	76	69	58	45	37
TX	Austin	AUS	51	56	63	69	76	82	85	85	80	71	61	53
TX	Brownsville	BRO	60	63	69	74	79	83	84	84	81	75	68	61
TX	College Station	CLL	51	56	63	69	76	82	85	85	80	71	61	53
TX	Corpus Christi	CRP	56	60	66	72	78	82	84	84	81	74	65	58
TX	Dallas-Ft. Worth	DFW	44	49	57	65	73	81	85	84	78	67	55	47
TX	Del Rio	DRT	51	56	64	71	78	83	85	85	80	71	60	52
TX	El Paso	ELP	45	51	57	65	74	82	83	81	75	65	53	45
TX	Galveston	GLS	56	58	64	70	77	82	84	84	81	74	65	58
TX	Houston	IAH	52	55	62	69	76	81	84	83	79	70	61	54
TX	Laredo	LRD	60	63	69	74	79	83	84	84	81	75	68	61
TX	Lubbock	LBB	38	43	51	60	69	77	80	78	71	61	48	40
TX	Lufkin	LFK	51	56	63	69	76	82	85	85	80	71	61	53
TX	McAllen	MFE	60	63	69	74	79	83	84	84	81	75	68	61
TX	Midland Odessa	MAF	43	49	56	64	73	80	82	80	74	64	52	45
TX	San Angelo	SJT	45	50	57	65	73	79	82	81	75	65	54	46
TX	San Antonio	SAT	50	55	62	69	76	82	84	84	79	71	60	52
TX	Victoria	VCT	53	57	64	70	77	82	84	84	80	72	63	55
TX	Waco	ACT	46	51	59	66	74	81	85	85	79	69	57	48

Station Location		Code	Monthly Average Outdoor Temperature											
State	City		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
TX	Wichita Falls	SPS	41	46	54	62	71	80	85	84	76	65	52	43
UT	Cedar City	CDC	29	35	43	50	59	69	77	76	65	53	40	30
UT	Salt Lake City	SLC	29	35	43	50	59	69	77	76	65	53	40	30
VA	Lynchburg	LYH	35	38	46	55	63	71	75	74	67	56	47	38
VA	Norfolk	ORF	40	42	49	57	66	75	79	77	72	61	52	44
VA	Richmond	RIC	36	40	48	57	65	74	78	76	70	58	49	40
VA	Roanoke	ROA	36	39	47	56	64	72	76	75	68	57	47	39
VT	Burlington	BTV	18	20	31	44	57	66	71	68	59	48	37	25
VT	Montpelier	MPV	18	20	31	44	57	66	71	68	59	48	37	25
WA	Bellingham	BLI	39	42	45	49	55	59	63	63	59	51	44	40
WA	Olympia	OLM	38	41	44	47	53	58	63	63	58	50	42	38
WA	Quillayute	UIL	41	42	44	47	51	55	59	59	57	50	44	41
WA	Seattle Tacoma	SEA	41	43	46	50	56	61	65	66	61	53	45	41
WA	Spokane	GEG	27	33	40	47	54	62	69	69	59	47	35	27
WA	Walla Walla	ALW	35	40	47	53	60	67	75	75	66	55	43	35
WA	Yakima	YKM	29	35	43	49	56	63	69	68	60	49	37	29
WI	Eau Claire	EAU	16	21	31	44	56	65	70	68	59	47	34	21
WI	Green Bay	GRB	16	21	31	44	56	65	70	68	59	47	34	21
WI	Lacrosse	LSE	16	23	35	48	61	70	74	72	63	51	36	22
WI	Madison	MSN	17	23	34	46	58	67	72	69	61	49	36	23
WI	Milwaukee	MKE	21	25	35	45	56	66	72	71	63	51	38	26
WI	Wausau	AUW	16	21	31	44	56	65	70	68	59	47	34	21
WV	Beckley	BKW	30	34	42	52	60	67	71	69	63	53	43	35
WV	Charleston	CRW	33	37	45	54	62	70	74	73	66	55	46	38
WV	Elkins	EKN	29	32	40	49	58	66	70	69	62	51	41	33
WV	Huntington	HTS	33	37	46	55	64	71	75	74	67	56	46	37
WV	Martinsburg	MRB	31	35	43	53	63	71	76	74	67	55	45	36
WV	Morgantown	MGW	31	35	43	53	63	71	76	74	67	55	45	36
WV	Parkersburg	PKB	31	35	43	53	63	71	76	74	67	55	45	36
WY	Casper	CPR	22	27	35	43	52	63	70	69	58	46	32	24
WY	Cheyenne	CYS	26	29	34	42	51	62	68	66	57	45	33	27
WY	Cody	COD	22	27	35	43	52	63	70	69	58	46	32	24
WY	Lander	LND	20	26	36	44	53	64	71	69	59	46	30	21
WY	Rock Springs	RKS	21	24	32	41	51	61	68	66	56	44	30	21
WY	Sheridan	SHR	21	27	35	44	53	62	69	68	57	45	31	22
WY	Worland	WRL	16	25	37	46	56	66	72	70	58	46	31	19

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APPENDIX 7D. REDUCED SET OF COMMERCIAL WARM AIR FURNACE MODELS AND CHARACTERISTICS

TABLE OF CONTENTS

7D.1 INTRODUCTION 7D-1
7D.2 REDUCED SET OF FURNACE MODELS DATABASE 7D-1
7D.2.1 Purpose 7D-1

LIST OF TABLES

Table 7D.2.1 Commercial Warm Air Furnace Manufacturers 7D-2

APPENDIX 7D. REDUCED SET OF COMMERCIAL WARM AIR FURNACE MODELS AND CHARACTERISTICS

7D.1 INTRODUCTION

This appendix presents the approach for developing a reduced set of commercial warm air furnace (CWAF) models and the resulting CWAF characteristics. The resulting input capacity and thermal efficiency (TE) distributions for CWAF are an essential component in the LCC analysis (see chapter 3 for detailed charts).

7D.2 REDUCED SET OF FURNACE MODELS DATABASE

7D.2.1 Purpose

The reduced set of CWAF models was developed to identify actual unique CWAF 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 August 2015 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. However, not all CWAF manufacturers are part of AHRI, so DOE also looked at other model directories, including the California Energy Commission (CEC),[2] CCMS database,[3] and manufacturer websites.

The August 2015 AHRI Directory and CCMS database lists more than 2,300 CWAF models. Many models represent essentially identical units which differ only in brand name. The database of CWAF models described here (referred to as the reduced set of CWAF models or simply the reduced set) represents non-repetitive CWAF models only. After examining the AHRI Directory database, the Department determined that about 181 models (167 gas-fired CWAFs and 14 oil-fired CWAFs) may be considered sufficiently different to be listed as unique models. See the Analytical Inputs spreadsheet ("Models Directory" worksheet) for a complete listing of models used for each CWAF equipment class.

Once the reduced set was identified, DOE examined manufacturers' product literature and added additional data. DOE identified the main CWAF manufacturers, shown in Table 7D.2.1, and the trade names of their CWAF lines.

Table 7D.2.1 Commercial Warm Air Furnace Manufacturers

Parent Company	Manufacturer/Brand Name	AHRI Directory
Aaon, Inc.	Aaon	NO
ABB Group	Reznor	NO
Adams Manufacturing Company	Adams Manufacturing	YES
	Dornback Manufacturing	YES
Boyertown Furnace	Boyertown Furnace	NO
Burnham Holdings Inc.	Thermo Pride	YES
Daikin	Daikin	YES
	Goodman	NO
	Amana	NO
	McQuay International	YES
Hastings Industries	Hastings	NO
Ingresoll Rand Plc.	American Standard	YES
	Trane	YES
Johnson Controls Inc.	Coleman	YES
	Evcon	YES
	Fraser-Johnston	YES
	Johnson Controls	YES
	Luxaire	YES
	York	YES
Lennox International	Allied Air Enterprises	YES
	AirEase	YES
	Armstrong Air	YES
	Lennox	YES
Modine Manufacturing Company	Modine	NO
Nortek Inc.	Nordyne	YES
Paloma Group	Heat Controller	YES
	Rheem	YES
	Ruud	YES
	Thermal Zone	YES
United Technologies Corporation	Bryant	YES
	Carrier	YES
	Airquest	YES
	Arcoaire	YES
	Comfortmaker	YES
	Day & Night	YES
	Heil	YES
	ICP Commercial	YES
	KeepRite	YES
	Tempstar	YES

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CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSIS

TABLE OF CONTENTS

8.1 INTRODUCTION 8-1
8.1.1 General Approach for Life-Cycle Cost and Payback Period Analysis 8-1
8.1.2 Overview of Life-Cycle Cost and Payback Period Analysis Inputs 8-2
8.1.3 Use of Commercial Building Energy Consumption Survey and Residential Energy Consumption Survey in Life-Cycle Cost and Payback Period Analysis 8-5
8.2 LIFE-CYCLE COST ANALYSIS INPUTS 8-6
8.2.1 Total Installed Cost Inputs 8-6
8.2.1.1 Manufacturer Costs 8-7
8.2.1.2 Markups 8-8
8.2.1.3 Total Customer Price 8-11
8.2.1.4 Future Equipment Prices 8-11
8.2.1.5 Installation Cost 8-13
8.2.1.6 Total Installed Cost 8-14
8.2.2 Operating Cost Inputs 8-15
8.2.2.1 Annual Energy Use Savings 8-15
8.2.2.2 Energy Prices 8-16
8.2.2.3 Repair Cost 8-19
8.2.2.4 Maintenance Cost 8-20
8.2.2.5 Lifetime 8-21
8.2.2.6 Discount Rates 8-21
8.2.2.7 Compliance Date of Standard 8-25
8.2.2.8 No-New-Standards Case Distribution of Efficiency Levels 8-25
8.3 PAYBACK PERIOD INPUTS 8-26
8.4 LIFE-CYCLE COSTS AND PAYBACK PERIOD RESULTS 8-27
8.4.1 Gas-Fired Commercial Warm Air Furnaces 8-27
8.4.2 Oil-Fired Commercial Warm Air Furnaces 8-29
8.5 REBUTTABLE PAYBACK PERIOD 8-30
8.5.1 Inputs 8-31
8.5.2 Results 8-31

LIST OF TABLES

Table 8.1.1 Summary of Inputs and Key Assumptions Used in the LCC and PBP Analysis 8-4
Table 8.2.1 Breakdown of Heat Exchanger Material Type by Efficiency Level for Outdoor Gas-fired Commercial Warm Air Furnaces 8-7
Table 8.2.2 Manufacturer Production Cost for Commercial Warm Air Furnaces by Efficiency Level 8-8
Table 8.2.3 Shipping Costs for Commercial Warm Air Furnaces by Efficiency Level 8-8
Table 8.2.4 Summary of Overall Markups on Commercial Warm Air Furnaces in Commercial Applications 8-9

Table 8.2.5 Summary of Overall Markups on Commercial Warm Air Furnaces in Residential Applications 8-10
Table 8.2.6 Overall Markup for Commercial Warm Air Furnaces by Equipment Class 8-11
Table 8.2.7 Average Customer Price for Commercial Warm Air Furnaces (2014$) 8-11
Table 8.2.8 Average Installation Cost for Commercial Warm Air Furnaces (2014$) 8-14
Table 8.2.9 Average Total Installed Cost for Commercial Warm Air Furnaces (2014$) 8-15
Table 8.2.10 Commercial Average Monthly Natural Gas Prices for 2013 Using Average Monthly Price Factors (2014$/MMBtu) 8-17
Table 8.2.11 Commercial Marginal Monthly Natural Gas Prices for 2013 Using Marginal Monthly Price Factors (2014$/MMBtu) 8-17
Table 8.2.12 Commercial Average Electricity Prices for 2013 Using Average Monthly Price Factors (2014$/kWh) 8-17
Table 8.2.13 Commercial Average Electricity Prices for 2013 Using Marginal Monthly Price Factors (2014$/kWh) 8-18
Table 8.2.14 Summary of Commercial Warm Air Furnaces Average and Marginal Prices in 2019 8-19
Table 8.2.15 Annualized Repair Cost for Commercial Warm Air Furnaces (2014$) 8-20
Table 8.2.16 Annualized Maintenance Cost for Commercial Warm Air Furnaces (2014$) 8-21
Table 8.2.17 Lifetime Parameters for Commercial Warm Air Furnaces 8-21
Table 8.2.18 Risk-Free Rate and Equity Risk Premium, 2010-2012 8-23
Table 8.2.19 Weighted Average Cost of Capital for Sectors that Purchase Commercial Warm Air Furnaces 8-24
Table 8.2.20 No-New-Standards Case Market Shares in 2019 by Efficiency Level for Commercial Warm Air Furnaces 8-26
Table 8.4.1 Gas-Fired Commercial Warm Air Furnaces: Average LCC and PBP Results 8-28
Table 8.4.2 Gas-Fired Commercial Warm Air Furnaces: LCC Savings Relative to the Base Case Efficiency Distribution 8-28
Table 8.4.3 Oil-Fired Commercial Warm Air Furnaces: LCC and PBP Results 8-29
Table 8.4.4 Gas-Fired Commercial Warm Air Furnaces: LCC Savings Relative to the Base Case Efficiency Distribution 8-30
Table 8.5.1 Rebuttable Payback Period for Gas-Fired Commercial Warm Air Furnaces 8-31
Table 8.5.2 Rebuttable Payback Period for Oil-Fired Commercial Warm Air Furnaces 8-32

LIST OF FIGURES

Figure 8.1.1 Flow Diagram of Inputs for the Determination of LCC and PBP 8-4
Figure 8.2.1 Historical Nominal and Deflated Producer Price Indexes for Commercial Warm Air Furnaces from 1989 to 2014 8-12
Figure 8.2.2 Projected National Commercial Energy Price Factors, AEO 2015 (Reference Case) 8-19
Figure 8.4.1 Distribution of LCC Savings for Gas-Fired Commercial Warm Air Furnaces 8-29

Figure 8.4.2 Distribution of LCC Savings for Oil-Fired Commercial Warm Air Furnaces 8-30

CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSIS

8.1 INTRODUCTION

The effect of amended standards on individual consumers 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 commercial consumers.

- Life-cycle cost (LCC) is the total consumer cost over the life of an appliance or product, including purchase costs and operating costs (which in turn include maintenance, repair, and energy costs). Future operating costs are discounted to the time of purchase and summed over the lifetime of the appliance or product.
- Payback period (PBP) measures the amount of time it takes consumers to recover the assumed higher purchase price of more energy-efficient equipment through reduced 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 of the key parameters as discussed further in section 8.1.1.

Inputs to the LCC and PBP analysis of commercial warm air furnace (CWAF) equipment are discussed in section 8.2 and Table 8.1.1. 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/product.aspx/productid/71).

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 commercial building that uses one or more furnaces is unique, variability and uncertainty are analyzed by performing the LCC and PBP calculations detailed here for a representative sample of individual commercial buildings and households. 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 models 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 commercial warm air furnace unit as described in the energy use analysis in chapter 7. Energy use of commercial warm air furnaces 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, equipment distribution markups, and sales taxes.

A certain fraction of commercial warm air furnaces are used for residential applications. This fraction determines the frequency at which the model's sampling process will select an item from the residential category.

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 consumers 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 a no-new-standards case. The no-new-standards case efficiency is for 2019 and reflects the expected distribution of efficiency levels by equipment class.

8.1.2 Overview of Life-Cycle Cost and Payback Period Analysis Inputs

The LCC is the total consumer cost over the life of the equipment, 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 equipment. The PBP is the increase in purchase cost of higher efficiency equipment divided by the change in annual operating cost of the equipment. It represents the number of years that it will take the consumer to recover the increased purchase cost through decreased operating costs. In the calculation of PBP, 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 equipment meeting existing minimum efficiency (or baseline) standards. The MSP includes a markup that converts the cost of production (*i.e.*, the manufacturer cost) to an MSP.
- *Standard-level manufacturer selling price increase*: The standard-level MSP is the incremental change in MSP associated with producing equipment at each of the higher efficiency standard 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 consumer price.
- *Installation cost*: Installation cost is the cost to the consumer of installing the equipment. The installation cost represents all costs required to install the equipment but does not include the marked-up consumer equipment price. The installation cost includes labor, overhead, and any miscellaneous materials and parts.

The primary inputs for calculating the operating cost are:

- *Equipment energy consumption*: The equipment energy consumption is the site energy use associated with the use of the furnace to provide space conditioning to the building.
- *Energy Prices*: Natural gas, liquid petroleum gas (LPG), fuel oil, and electrcity 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 furnace 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.

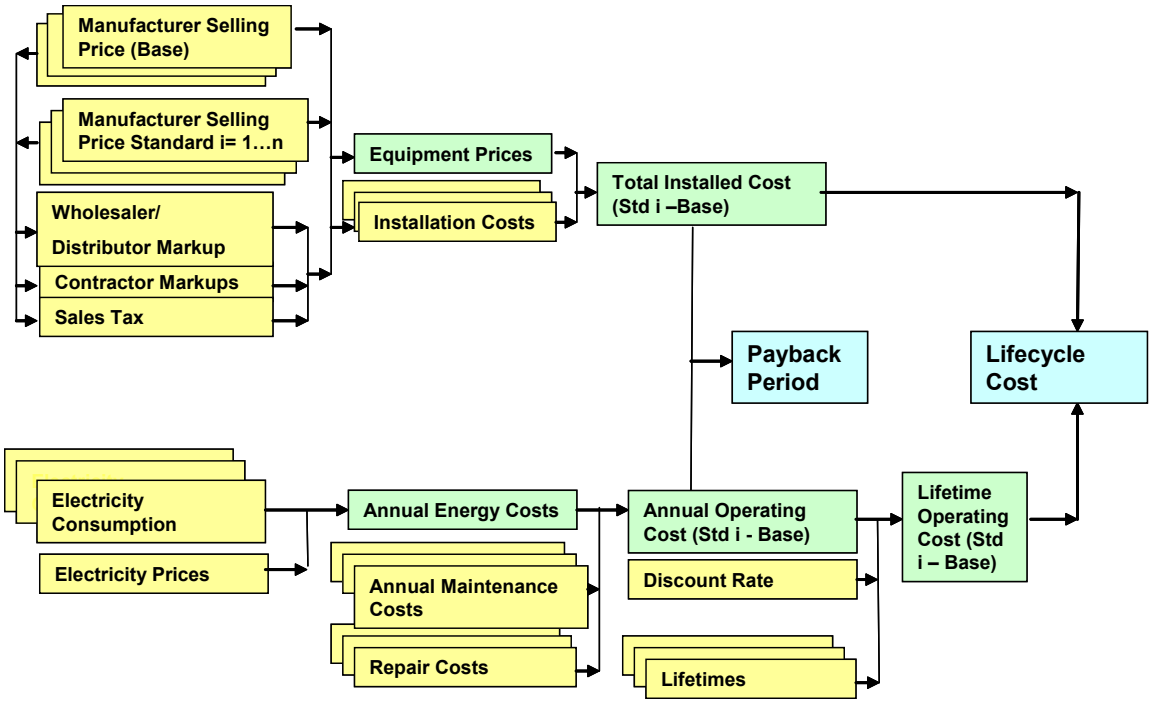

Figure 8.1.1 Flow Diagram of Inputs for the Determination of LCC and PBP

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	
Equipment Price	Derived MSP for CWAF units at different heating and air conditioning 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 Mechanical Cost Data 2013*.[2] Overhead and materials costs and profits are assumed to be included in the contractor's markup. Thus, the total installed cost equals the consumer equipment 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	Thermal efficiency (TE) is the efficiency descriptor for CWAF. CWAF test procedure calculation methodologies are used to determine the annual energy consumption associated with the considered standard levels.
Energy Prices	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. 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.
Maintenance Cost	The cost associated with maintaining the operation of the equipment (*e.g.*, checking blower). It was assumed that maintenance costs would vary for higher efficiency levels.
Repair Cost	Estimated the annualized repair cost for baseline efficiency CWAF equipment, based on costs of major repair (such as motor replacement), from a variety of published sources. It is assumed that repair costs would vary for higher efficiency levels.
Affecting Present Value of Annual Operating Cost Savings	
Equipment Lifetime	For gas-fired commercial warm air furnaces, the lifetime probability distribution was developed is based on the commercial unitary air-conditioning equipment in the 2014 NOPR for this equipment. For oil-fired commercial warm air furnaces, the lifetime probability distribution is based on the residential oil-fired furnace lifetime distribution in the 2009 residential furnacesdirect final rule.
Discount Rate	The mean real discount rates ranges from 2.46 to 5.88 percent for various classes of commercial customers, calculated using financial data from Damodaran Online. Probability distributions are used for the discount rates.
Date Standard Becomes Effective*	2019 (3 years after expected publication of the final rule)

* The negotiated compliance date for CWAF standards is January 1, 2023. For all other TSLs, the compliance date would be January 1, 2019. For purposes of the LCC and PBP analysis, DOE used 2019 as the first full year of compliance for all TSLs.

All of the inputs depicted in Figure 8.1.1 and summarized in Table 8.1.1 are discussed in sections 8.2 and 8.3.

8.1.3 Use of Commercial Building Energy Consumption Survey and Residential 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 furnace users. The commercial warm air furnaces are assumed to be installed both in commercial and residential buildings.

As explained in chapter 7, the Energy Information Administration (EIA)'s 2003 Commercial Building Energy Consumption Survey (CBECS 2003)[3] serves as the basis for determining the representative commercial sample, and EIA's 2009 Residential Energy

[a] RECS 2009 provides 27 regions (also called reportable domains). The 27th region originally included 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. See appendix 7A for more details.

Consumption Survey (RECS 2009)[4] serves as the basis for determining the representative residential sample CBECS collects energy-related data for commercial buildings in the United States. CBECS 2003 includes data from 5,215 buildings representing 4.9 million buildings. RECS collects energy-related data for occupied primary housing units in the United States. RECS 2009 includes data from 12,083 housing units that represent almost 113.6 million households.

Appendix 7A presents the variables used and their definitions, as well as further information about the derivation of the building and household samples.

8.2 LIFE-CYCLE COST ANALYSIS INPUTS

Life-cycle cost is the total consumer cost over the life of the equipment, including purchase cost and operating costs (which are composed of energy costs, maintenance costs, and repair costs). Future operating costs are discounted to the time of purchase and summed over the lifetime of the equipment. 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 equipment (years),
OC = operating cost ($),
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 equipment purchase is assumed to be 2019, the assumed effective date of energy conservation standards for CWAF used in the LCC analysis.

8.2.1 Total Installed Cost Inputs

The total installed cost to the customer is defined by the following equation:

$$IC = EQP + INST$$

Eq. 8.2

Where:

EQP = equipment price ($) (*i.e.*, customer price for the equipment only), and
INST = installation cost ($) (*i.e.*, the cost for labor and materials).

The equipment price is based on the distribution channel through which the customer purchases the equipment. As discussed in chapter 6, DOE defined one major distribution channel for new units to describe how the equipment passes from the manufacturer to the customer: the manufacturer sells the equipment to a wholesaler or distributor, who sells to a mechanical contractor hired by a general contractor. The general contractor purchases and installs the equipment on behalf of the customer and adds its markup to the mechanical contractor's price. Replacement equipment follows 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 CWAF equipment.

8.2.1.1 Manufacturer Costs

DOE developed the manufacturer production costs (MPC) for CWAF as described in chapter 5, Engineering Analysis, of this technical support document (TSD). The percentages of units estimated to use each heat exchanger material type at the non-condensing efficiency levels for outdoor gas-fired CWAF (packaged with a CUAC), as well as the MPC at each efficiency level for each material type, are shown in Table 8.2.1.[b] The manufacturer costs at each efficiency level are shown in Table 8.2.2. The manufacturer costs for non-condensing gas-fired CWAF reflect the fractions of gas-fired CWAF with aluminized or stainless steel heat exchangers, as described in chapter 5. The MPC for gas-fired CWAF are the incremental costs of the gas-fired CWAF as part of a packaged unit with a commercial unitary air conditioner (CUAC), while the MPC of oil-fired CWAF is for the entire unit. DOE also considered shipping costs from the manufacturer for these units, which are shown in Table 8.2.3. The shipping costs for gas-fired CWAF are the incremental cost compared to the baseline shipping cost of a baseline gas-fired CWAF, while the shipping costs for oil-fired CWAF are the total shipping cost.

Table 8.2.1 Breakdown of Heat Exchanger Material Type by Efficiency Level for Outdoor Gas-fired Commercial Warm Air Furnaces

Thermal Efficiency (%)	Aluminized CRS		SS409		SS316	
	Fraction	MPC (2014$)	Fraction	MPC (2014$)	Fraction	MPC (2014$)
80	85%	$337.21	11%	$447.01	4%	$599.48
81	85%	$350.40	11%	$469.39	4%	$634.86
82	0%	$357.42	25%	$485.62	75%	$664.10

[b] DOE assumed that all indoor gas-fired CWAF (5 percent of shipments) are made with aluminized cold rolled steel (CRS).

Table 8.2.2 Manufacturer Production Cost for Commercial Warm Air Furnaces by Efficiency Level

Equipment Class	Efficiency Level	Manufacturer Production Cost (MPC) 2014$	Incremental MPC 2014$
Gas-fired CWAF	80% TE - Baseline	$358.29	--
	81% TE - Increased HX Area	$373.25	$14.96
	82% TE - Increased HX Area	$606.38	$248.09
	92% TE - Condensing (Max Tech)	$1,073.81	$715.52
Oil-fired CWAF	81% TE - Baseline	$1,613.43	--
	82% TE - Increased HX Area	$1,638.20	$24.77
	92% TE - Condensing (Max Tech)	$2,304.24	$690.81

Table 8.2.3 Shipping Costs for Commercial Warm Air Furnaces by Efficiency Level

Equipment Class	Efficiency Level	Shipping Costs	Incremental MPC
		2014$	2014$
Gas-fired CWAF	80% TE - Baseline	$0.00	
	81% TE - Increased HX Area	$0.00	$0.00
	82% TE - Increased HX Area	$0.00	$0.00
	92% TE - Condensing (Max Tech)	$43.15	$43.15
Oil-fired CWAF	81% TE - Baseline	$69.43	
	82% TE - Increased HX Area	$75.76	$6.33
	92% TE - Condensing (Max Tech)	$83.31	$13.88

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 equipment is being purchased for a new construction installation or is being purchased to replace existing

equipment. 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 of this TSD).

The following tables present the overall markups and their associated components for both baseline and incremental markups: Table 8.2.4 (for commercial applications), Table 8.2.5 (for residential applications), and Table 8.2.6 (overall weighted average). The results are based on the percentages of the market attributed to each distribution channel and the respective weights of the replacement and the new construction sectors.

Table 8.2.4 Summary of Overall Markups on Commercial Warm Air Furnaces in Commercial Applications

	Replacement			New Construction		
	Baseline Markup	**Incremental Markup**	**National Account: Baseline/ Incr. MU**	**Baseline Markup**	**Incremental Markup**	**National Account: Baseline/ Incr. MU**
Gas-fired CWAFs						
Manufacturer	1.31			1.31		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.61	1.12/1.29	
General Contractor (Commercial Building)	--	--		1.31	1.19	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	3.22	2.10	2.03/1.50	3.76	2.21	2.28/1.55
Oil-fired CWAFs						
Manufacturer	1.28			1.28		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.61	1.12/1.29	
General Contractor (Commercial Building)	--	--		1.31	1.19	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	3.15	2.05	2.00/1.47	3.67	2.16	2.24/1.53

Table 8.2.5 Summary of Overall Markups on Commercial Warm Air Furnaces in Residential Applications

	Replacement			New Construction		
	Baseline Markup	**Incremental Markup**	**National Account: Baseline/ Incr. MU**	**Baseline Markup**	**Incremental Markup**	**National Account: Baseline/ Incr. MU**
Gas-fired CWAFs						
Manufacturer	1.31			1.31		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.61	1.12/1.29	
General Contractor (Residential Building)	--	--		1.47	1.34	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	2.82	1.83	2.03/1.50	3.24	1.92	2.50/1.80
Oil-fired CWAFs						
Manufacturer	1.28			1.28		
Wholesaler	1.36	1.10		1.36	1.10	
Mechanical Contractor (large/small)	1.48/1.69	1.19/1.36		1.39/1.16	1.12/1.29	
General Contractor (Residential Building)	--	--		1.47	1.34	
Sales Tax	1.07	1.07		--	--	
Overall Markup (large/small)	2.76	1.79	2.00/1.47	3.17	1.88	2.45/1.77

Because the relative importance of new construction and replacements in total shipments varies among the equipment classes, the total markup varies as well (Table 8.2.6).

Table 8.2.6 Overall Markup for Commercial Warm Air Furnaces by Equipment Class

Equipment Class	Baseline Markup	Incremental Markup
Gas-Fired Commercial Warm Air Furnace	2.96	1.92
Oil-Fired Commercial Warm Air Furnace	2.84	1.85

8.2.1.3 Total Customer Price

DOE derived the customer equipment price for the efficiency levels above the baseline by taking the product of the baseline manufacturer cost and the baseline overall markup (including the sales tax) and adding to it the product of the incremental manufacturer cost and the incremental overall markup (including the sales tax). Markups and the 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 8.2.7 presents the average commercial consumer equipment price for each CWAF equipment class at each efficiency level examined in 2019.

Table 8.2.7 Average Customer Price for Commercial Warm Air Furnaces (2014$)

Equipment Class	Efficiency Level	Average Consumer Price 2014$	Incremental Cost 2014$
Gas-fired CWAF	80% TE - Baseline	$1,008.43	$0.00
	81% TE - Increased HX Area	$1,035.57	$27.14
	82% TE - Increased HX Area	$1,464.32	$455.89
	92% TE - Condensing (Max Tech)	$2,380.39	$1,371.96
Oil-fired CWAF	81% TE - Baseline	$4,515.67	$0.00
	82% TE - Increased HX Area	$4,568.29	$52.63
	92% TE - Condensing (Max Tech)	$5,755.18	$1,239.51

8.2.1.4 Future Equipment Prices

In its 2011 central air conditioning, heat pump, and furnace standards rulemaking,[5] DOE derived a forecast of future furnace prices based on an analysis of the historic trend in the producer price index (PPI) for furnaces. Similarly, DOE believes that using the appropriate historical PPI provides a reasonable basis for modeling the price trend of CWAF. The two equipment classes considered in this rulemaking are both similar to indoor or non-weatherized residential gas and oil-fired furnaces; therefore, DOE used the "warm air furnaces" PPI series to estimate the price trend for CWAF.

DOE obtained historical PPI data for warm air furnaces spanning the time period 1989-2014 from the Bureau of Labor Statistics' (BLS).[c] The PPI data reflect nominal prices, adjusted for equipment quality changes. An inflation-adjusted (deflated) price index for warm air furnaces was calculated by dividing the PPI series by the Gross Domestic Product Chained Price Index, and the deflated price index was normalized to 1 in 2014 (see Figure 8.2.1).

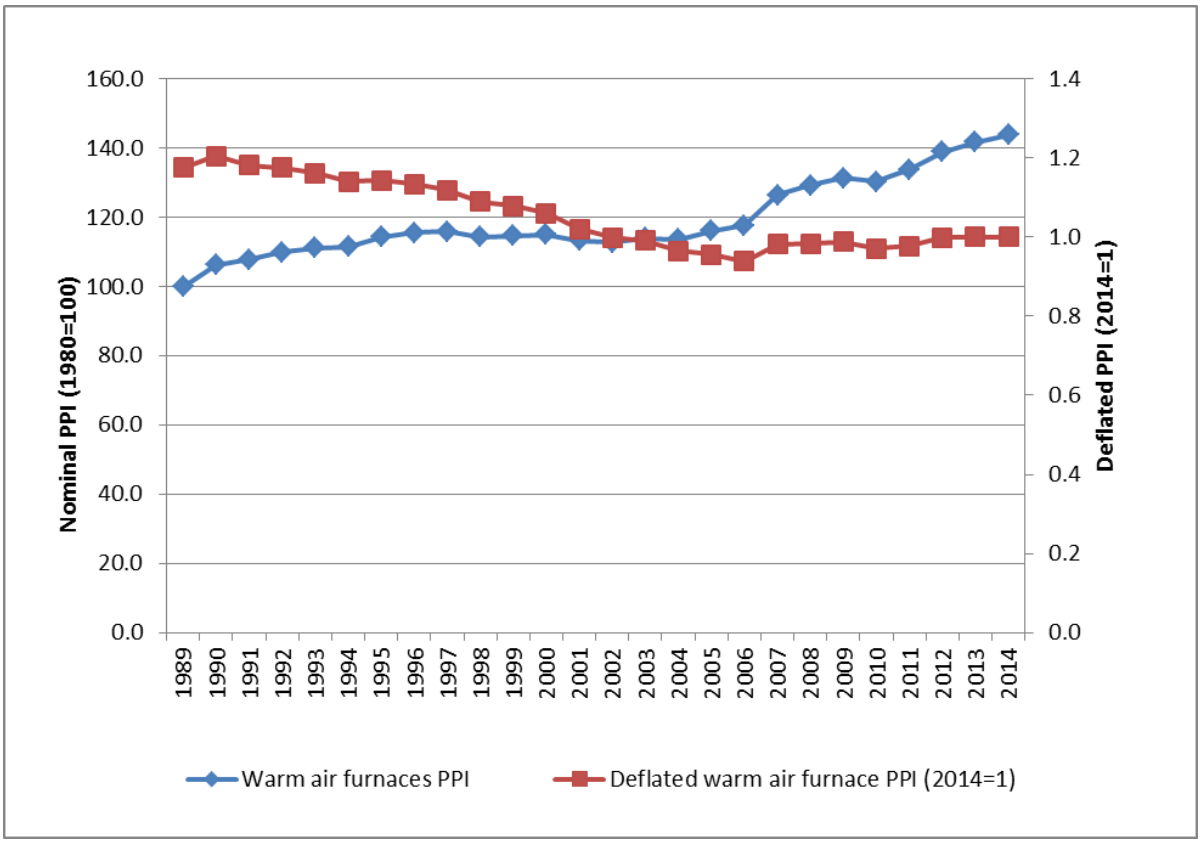

Figure 8.2.1 Historical Nominal and Deflated Producer Price Indexes for Commercial Warm Air Furnaces from 1989 to 2014

For this preliminary analysis, DOE projected the future prices of CWAF based on the PPI series fitting with an exponential function, with *year* as the explanatory variable. In this case, the functional form looks like the following:

$$Y = a \cdot e^{bX}$$

Eq. 8.3

Where:

Y = warm air furnace index,
X = time variable,
a = constant, and
b = slope parameter of the time variable.

[c] Series ID PCU333415333415C; www.bls.gov/ppi/.

The regression was performed as an exponential trend line fit, resulting in an R-square of 0.80, which indicates a decent fit to the data. The regression results also imply an annual price decline rate of 1.07 percent for both types of commercial warm air furnaces. The final estimated exponential function is:

$$Y = 1.445 \times 10^8 \cdot e^{(-0.009)X}$$

Eq. 8.4

DOE then derived a price factor index, with 2014 equal to 1, to project the equipment prices in 2019, the compliance date for amended energy conservation standards in the LCC and PBP analysis. Based on the fitted function, DOE estimated the index value in 2019 to be equal to 0.954, as a function of the exponential parameter and time (*year*). DOE applied the same values to project prices for both types of CWAF at each considered efficiency level.

8.2.1.5 Installation Cost

The installation cost is the cost to the commercial consumer of installing the CWAF. The cost of installation covers all labor and material costs associated with the replacement of an existing CWAF or the installation of a CWAF in a new building, as well as delivery of the new CWAF, removal of the existing CWAF, and any applicable permit fees. Higher-efficiency CWAF may require additional installation costs. DOE's analysis of installation costs estimated specific installation costs for each sample building based on building characteristics given in CBECS 2003 and RECS 2009.

DOE estimated the installation costs using a variety of sources, including 2013 RS Means Mechanical Cost Data, manufacturer literature, and information from expert consultants. DOE's analysis of installation costs accounts for regional differences in labor costs. For a detailed discussion of the development of installation costs, see appendix 8D.

DOE gave separate consideration to the cost of installing condensing CWAF in replacement cases and in new buildings.[d] DOE conducted a detailed analysis of installation costs when a non-condensing CWAF is replaced with a condensing CWAF, with particular attention to condensate and venting issues in replacement applications. The installation cost depends on the CWAF installation location (outdoor or indoor).[e]

DOE estimated basic installation costs that are applicable to both replacement and new construction installations. These costs, which apply to all CWAF, include putting in place and setting up the furnace, gas piping, ductwork, electrical hookup for the thermostat, and permit, removal or disposal fees.

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[d] For gas-fired CWAF, DOE assumed that 80 percent are replacements and 20 percent are new construction. For oil-fired CWAF, 95 percent are replacements and 5 percent are new construction.

[e] For gas-fired CWAF, DOE assumed that 95 percent are outdoor units and 5 percent are indoor units. For oil-fired CWAF, 100 percent are assumed to be indoor units.

DOE included a number of additional costs ("adders") for a fraction of the sample buildings. For non-condensing CWAF installed outdoors, there are no additional costs. For non-condensing CWAF installed indoors, these additional costs include updating venting for replacement installations (*e.g.*, flue vent connectors, vent resizing, and chimney relining) and a new flue vent (metal) for new construction installations. For condensing CWAF installed outdoors, these additional costs include condensate removal. For condensing CWAF installed indoors, the adders included a new flue vent (PVC), combustion air vent for direct vent installations (PVC), concealing vent pipes for replacement installations, and condensate removal. These cost components were included in the overall installation cost as applicable for each installation.

Condensing CWAF installed outdoors that are located in regions with an outdoor design temperature of less than 32 °F were assumed to require condensate freeze protection. This applies to roughly 90 percent of gas-fired CWAF. Freeze protection (heat tape) is accounted for in the cost of condensate removal for these CWAF. All oil-fired CWAF are assumed to be installed indoors, so condensate line freeze protection was assumed to not be needed.

Table 8.2.8 presents the average installation cost by efficiency level for each equipment class. For further details on installation costs for CWAF, see appendix 8D.

Table 8.2.8 Average Installation Cost for Commercial Warm Air Furnaces (2014$)

Equipment Class	Efficiency Level	Total Installed Cost 2014$	Incremental Cost 2014$
Gas-fired CWAF	80% TE - Baseline	$1,078.79	-
	81% TE - Increased HX Area	$1,078.79	$0.00
	82% TE - Increased HX Area	$1,078.79	$0.00
	92% TE - Condensing (Max Tech)	$1,459.59	$380.79
Oil-fired CWAF	81% TE - Baseline	$1,841.75	-
	82% TE - Increased HX Area	$1,841.75	$0.00
	92% TE - Condensing (Max Tech)	$2,106.19	$264.44

8.2.1.6 Total Installed Cost

The total installed cost is the sum of the equipment 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 8.2.9 presents the average total installed cost for each commercial warm air furnace equipment class at each efficiency level examined.

Table 8.2.9 Average Total Installed Cost for Commercial Warm Air Furnaces (2014$)

Equipment Class	Efficiency Level	Total Installed Cost 2014$	Incremental Cost 2014$
Gas-fired CWAF	80% TE - Baseline	$2,087.22	-
	81% TE - Increased HX Area	$2,114.36	$27.14
	82% TE - Increased HX Area	$2,543.11	$455.89
	92% TE - Condensing (Max Tech)	$3,839.98	$1,752.75
Oil-fired CWAF	81% TE - Baseline	$6,357.42	-
	82% TE - Increased HX Area	$6,410.04	$52.63
	92% TE - Condensing (Max Tech)	$7,861.37	$1,503.95

8.2.2 Operating Cost Inputs

DOE defined the operating cost by the following equation:

$$OC = EC + RC + MC$$

Eq. 8.5

Where:

OC = operating cost ($),
EC = energy cost associated with operating the equipment ($),
RC = repair cost associated with component failure ($), and
MC = annual maintenance cost for maintaining equipment operation ($).

The remainder of this section provides information about the variables that DOE used to calculate the operating cost for commercial warm air furnaces. The annual energy costs of the equipment are computed from energy consumption per unit for the baseline and standard-compliant cases (efficiency level 1, 2, and so on), combined with the energy prices. Equipment 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 equipment class, DOE calculated the annual energy use savings for each building sample at each efficiency level as described in chapter 7. Because it is unlikely that users of CWAF may use a higher-efficiency CWAF more than a baseline one, DOE did not include a (direct) rebound effect in its analyses.

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 assigns an appropriate energy price to each commercial building and household in the sample, depending on its sector (commercial or residential) and location.

Derivation of Average and Marginal Monthly Prices

Derivation of Average Annual Energy Prices using EIA data. DOE derived 2013 annual natural gas prices from EIA's Natural Gas Navigator,[6] which includes monthly natural gas prices by state for residential, commercial, and industrial consumers. DOE derived 2013 annual electricity prices from EIA Form 826 data,[7] which includes electricity prices by state for residential, commercial, and industrial consumers. DOE calculated annual state electricity and natural gas prices by averaging monthly energy prices by state.

DOE collected 2013 annual average LPG and oil prices from EIA's 2013 State Energy Consumption, Price, and Expenditures Estimates (SEDS).[8] SEDS includes annual LPG and oil prices for residential, commercial, industrial, and transportation consumers by state.

For CBECS or RECS region with more than one state, DOE weighted each state's average energy price by its number of buildings in 2019. See appendix 8C for the calculated annual energy prices in 2013.

Derivation of Average Monthly Energy 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 8C for a description of the method. DOE multiplied the average 2013 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 8C.

Table 8.2.10 through Table 8.2.13 show the commercial average and marginal monthly natural gas and electricity prices. Average commercial LPG and fuel oil prices and residential prices are shown in appendix 8C.

Table 8.2.10 Commercial Average Monthly Natural Gas Prices for 2013 Using Average Monthly Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	10.94	10.97	10.96	10.86	10.03	9.80	10.04	9.92	9.84	9.64	10.60	11.08
Middle Atlantic	9.27	9.14	8.91	8.75	8.69	8.59	8.34	8.12	8.18	8.33	8.73	9.10
East North Central	7.04	6.99	7.05	7.25	7.70	8.20	8.46	8.41	7.93	7.20	7.13	7.08
West North Central	7.76	7.68	7.63	7.64	7.98	8.32	8.54	8.59	8.30	7.76	7.82	7.75
South Atlantic	9.32	9.36	9.35	9.34	9.48	9.69	9.84	9.69	9.62	9.49	9.43	9.44
East South Central	8.96	8.93	8.89	9.07	9.23	9.37	9.46	9.53	9.38	9.40	9.33	9.19
West South Central	7.55	7.46	7.18	7.30	7.63	7.66	7.70	7.56	7.65	7.80	7.91	7.62
Mountain	7.21	7.25	7.27	7.24	7.37	7.53	7.75	7.87	7.72	7.48	7.45	7.30
Pacific	9.10	8.98	8.77	8.54	8.20	8.47	8.41	8.46	8.30	8.31	8.58	9.02
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 8.2.11 Commercial Marginal Monthly Natural Gas Prices for 2013 Using Marginal Monthly Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	10.92	10.95	10.94	11.12	10.27	10.03	10.27	10.15	10.07	9.87	10.59	11.07
Middle Atlantic	9.20	9.07	8.84	8.68	8.62	8.52	8.28	8.06	8.12	8.26	8.66	9.03
East North Central	6.99	6.93	7.00	7.19	7.64	8.13	8.39	8.35	7.86	7.14	7.07	7.02
West North Central	7.67	7.60	7.55	7.56	7.89	8.24	8.45	8.50	8.21	7.68	7.73	7.67
South Atlantic	8.94	8.98	8.97	8.96	9.09	9.30	9.44	9.29	9.23	9.10	9.04	9.06
East South Central	8.48	8.46	8.42	8.59	8.74	8.87	8.96	9.03	8.88	8.90	8.84	8.71
West South Central	6.96	6.87	6.61	6.73	7.03	7.06	7.09	6.97	7.05	7.19	7.29	7.03
Mountain	6.98	7.02	7.04	7.01	7.13	7.28	7.50	7.62	7.47	7.24	7.21	7.06
Pacific	10.79	10.65	10.40	10.13	9.72	10.04	9.97	10.03	9.85	9.85	10.17	10.70
United States	7.85	7.84	7.80	7.81	7.87	7.99	7.98	7.88	7.85	7.71	7.84	7.89

Table 8.2.12 Commercial Average Electricity Prices for 2013 Using Average Monthly Price Factors (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.132	0.135	0.132	0.132	0.131	0.139	0.140	0.139	0.141	0.135	0.132	0.136
Middle Atlantic	0.119	0.119	0.119	0.119	0.123	0.131	0.135	0.134	0.132	0.126	0.120	0.120
East North Central	0.088	0.091	0.092	0.093	0.094	0.095	0.095	0.095	0.094	0.095	0.092	0.090
West North Central	0.079	0.081	0.082	0.083	0.089	0.096	0.097	0.097	0.091	0.084	0.082	0.081
South Atlantic	0.088	0.090	0.090	0.090	0.090	0.092	0.092	0.093	0.092	0.091	0.090	0.090
East South Central	0.093	0.094	0.095	0.095	0.095	0.096	0.095	0.096	0.095	0.095	0.096	0.095
West South Central	0.077	0.078	0.079	0.078	0.078	0.080	0.079	0.080	0.078	0.079	0.077	0.077
Mountain	0.085	0.087	0.087	0.089	0.091	0.094	0.092	0.092	0.092	0.093	0.089	0.087
Pacific	0.118	0.121	0.120	0.121	0.126	0.138	0.144	0.142	0.140	0.136	0.128	0.121
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 8.2.13 Commercial Average Electricity Prices for 2013 Using Marginal Monthly Price Factors (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.122	0.125	0.123	0.148	0.147	0.156	0.156	0.155	0.157	0.151	0.122	0.126
Middle Atlantic	0.113	0.113	0.113	0.172	0.177	0.189	0.194	0.192	0.190	0.182	0.114	0.114
East North Central	0.066	0.068	0.069	0.102	0.103	0.105	0.105	0.105	0.104	0.104	0.069	0.067
West North Central	0.052	0.053	0.054	0.132	0.141	0.153	0.154	0.154	0.144	0.133	0.054	0.053
South Atlantic	0.076	0.078	0.078	0.097	0.098	0.100	0.100	0.101	0.100	0.099	0.078	0.078
East South Central	0.075	0.076	0.077	0.099	0.099	0.100	0.099	0.100	0.099	0.099	0.077	0.077
West South Central	0.061	0.063	0.063	0.089	0.089	0.091	0.090	0.091	0.089	0.090	0.062	0.062
Mountain	0.089	0.091	0.091	0.103	0.106	0.109	0.107	0.107	0.107	0.108	0.093	0.090
Pacific	0.097	0.099	0.099	0.198	0.207	0.226	0.236	0.234	0.230	0.223	0.105	0.100
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

Building Energy Price Adjustment Factor

CBECS 2003 and RECS 2009 report the total annual consumption and expenditure of each fuel type. To take into account that building energy prices vary inside a geographical area, DOE developed an adjustment factor based on the reported average energy price in CBECS 2003 and RECS 2009 for each building divided by the average energy price in the geographical region in CBECS 2003 and RECS 2009. The monthly price was then multiplied by this adjustment factor to determine the building energy price. Appendix 8C includes more details.

Energy Price Trends by Census Division

To arrive at prices in future years, DOE multiplied the prices described in the preceding section by the forecasts of annual average price changes by census division in EIA's *AEO 2015*. Figure 8.2.2 shows national commercial energy price factors with the base year of 2013 (2013=1). To estimate the trend after 2040, DOE used the average rate of change during 2030–2040. For more details, including residential energy price factors, see appendix 8C.

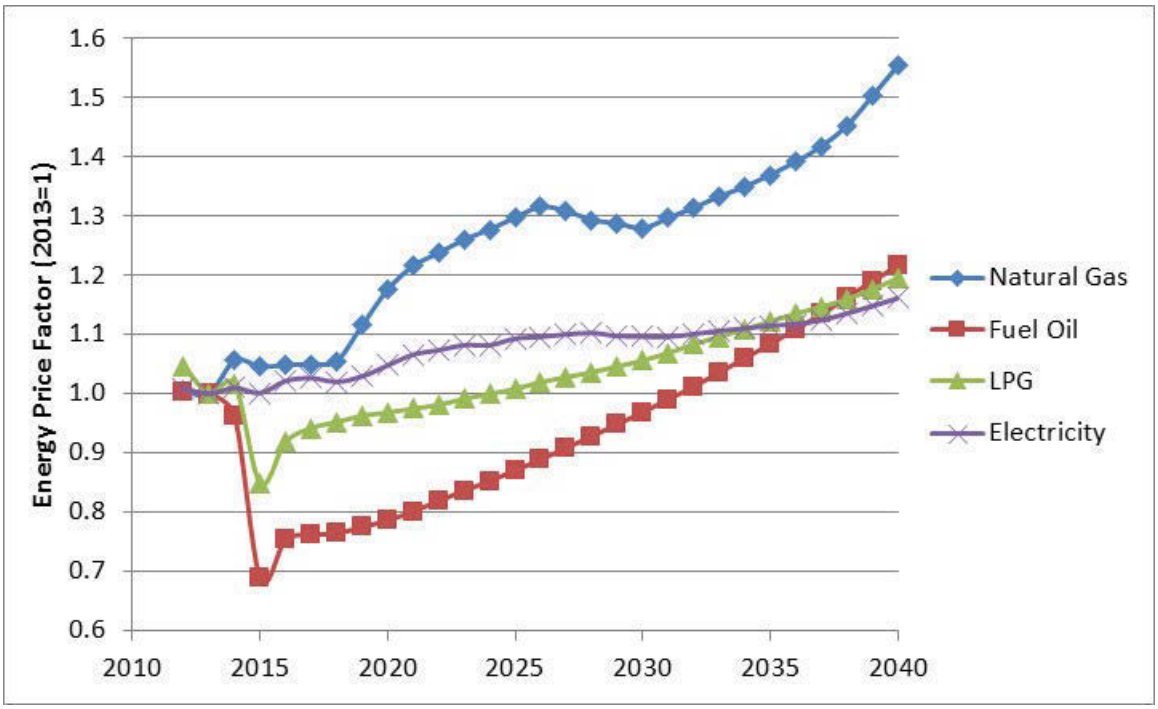

Figure 8.2.2 Projected National Commercial Energy Price Factors, AEO 2015 (Reference Case)

Overall Summary Results

Table 8.2.14 presents the resulting average and marginal energy prices in 2019 for all CWAF. The average price is applied to the no-new-standards case energy use. The marginal price is applied to the energy savings when comparing each efficiency level to the no-new-standards case.

Table 8.2.14 Summary of Commercial Warm Air Furnaces Average and Marginal Prices in 2019

Energy Price	Unit	Energy Prices (2014$)	
		Average	Marginal
Gas-fired CWAF			
Natural Gas	2014$/MMbtu	8.34	8.13
Electricity	2014$/kWh	0.10	0.09
Oil-fired CWAF			
Fuel Oil	2014$/MMbtu	28.93	28.93
Electricity	2014$/kWh	0.11	0.12

8.2.2.3 Repair Cost

The repair cost is the cost to the customer for replacing or repairing components in the commercial warm air furnace that have failed. DOE considered the controls, the fan motor, and the burner as potential repairs for a fraction of CWAF. The repair costs at each considered

efficiency level were based on *2013 RS Means Mechanical Cost Data* and *2013 RS Means Facilities Maintenance and Repair Data.*[2,9] DOE accounts for regional differences in labor costs. For a detailed discussion of the development of repair costs, see appendix 8E. DOE included additional repair costs for higher efficiency levels (*i.e.*, condensing CWAF).

Table 8.2.15 shows the annualized repair cost estimates for each equipment class.

Table 8.2.15 Annualized Repair Cost for Commercial Warm Air Furnaces (2014$)

Equipment Class	Efficiency Level	Annualized Repair Cost 2014$	Incremental Cost 2014$
Gas-fired CWAF	80% TE - Baseline	$0.69	$0.00
	81% TE - Increased HX Area	$0.71	$0.02
	82% TE - Increased HX Area	$1.00	$0.31
	92% TE - Condensing (Max Tech)	$1.58	$0.89
Oil-fired CWAF	81% TE - Baseline	$2.35	$0.00
	82% TE - Increased HX Area	$2.38	$0.03
	92% TE - Condensing (Max Tech)	$3.23	$0.88

8.2.2.4 Maintenance Cost

The maintenance cost is the routine cost to the customer of maintaining equipment operation. DOE included increased maintenance costs for condensing equipment. Table 8.2.16 shows the annualized maintenance cost estimates for each equipment class.

Labor hours and costs for annual maintenance were estimated using RS Means data. The frequency with which the maintenance occurs was derived from a CBECS 2003 and RECS 2009 data. DOE included additional repair costs for higher efficiency levels (*i.e.*, condensing CWAF). For condensing CWAF, DOE included additional labor hours to inspect condesate withdrawal system. In addition, for condensing oil-fired CWAF, DOE included additional labor hours to clean the secondary heat exchanger in areas not using low sulfur fuel oil. For a detailed discussion of the development of maintenance costs, see appendix 8E.

Table 8.2.16 Annualized Maintenance Cost for Commercial Warm Air Furnaces (2014$)

Equipment Class	Efficiency Level	Annualized Maintenance Cost 2014$	Incremental Cost 2014$
Gas-fired CWAF	80% TE - Baseline	$160.70	$0.00
	81% TE - Increased HX Area	$160.70	$0.00
	82% TE - Increased HX Area	$160.70	$0.00
	92% TE - Condensing (Max Tech)	$172.63	$11.92
Oil-fired CWAF	81% TE - Baseline	$294.30	$0.00
	82% TE - Increased HX Area	$294.30	$0.00
	92% TE - Condensing (Max Tech)	$321.94	$27.64

8.2.2.5 Lifetime

DOE defines lifetime as the age when equipment is retired from service. For all CWAF, the lifetime probability distribution is based on commercial unitary air-conditioning (CUAC) equipment lifetime in the 2014 CUAC NOPR.[10] For a detailed discussion of the development of CWAF lifetimes, see appendix 8F of this TSD.

Table 8.2.17 shows the the average and median lifetime values as well as the Weibull distribution parameters alpha, beta, and location (delay). DOE assumed that the lifetime of a CWAF does not vary across the different efficiency levels.

Table 8.2.17 Lifetime Parameters for Commercial Warm Air Furnaces

Equipment Class	Lifetime Distribution Statistics		Weibull Parameters		
	Average	Median	Alpha (scale)	Beta (shape)	Location (delay)
All CWAF	23.0	22.1	24.81	2.3	1

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 estimates discount rates separately for commercial and residential end users. For commercial end users, DOE calculates commercial discount rates as the weighted average cost of capital (WACC), using the Capital Asset Pricing Model (CAPM). For residential end users, DOE calculates discount rates as the weighted average real interest rate across consumer debt and equity holdings.

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 equipment 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 commercial warm air furnaces. 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 commercial warm air furnaces.[11]

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.[12] Companies included in the Damondaran 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 CAPM.[13] 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. 8.6

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."[14]

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 2011-2013 (Table 8.2.18).[15] DOE also estimated the ERP by calculating the difference between risk-free rates and stock market return for the same time period.[16]

Table 8.2.18 Risk-Free Rate and Equity Risk Premium, 2010-2012

Year	Risk-free rate (%)	ERP (%)
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:

$$k_{di} = R_f + R_{ai}$$

Eq. 8.7

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. 8.8

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 commercial warm air furnace analysis. These values are presented in Table 8.2.19, which provides results for average- to large-sized companies. Discount rates for small companies are estimated using a modification of the CAPM model, discussed in the LCC subgroup analysis (chapter 11). 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 8.2.19 Weighted Average Cost of Capital for Sectors that Purchase Commercial Warm Air Furnaces

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	1.18
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,* 2011,2012,2013.

Discount Rates for Residential Applications

In the few residential applications of CWAF, the customers are likely to be the building owners and not the actual household occupants. Therefore, the discount rates applied to replacement and new construction residential applications are the discount rates for property owners described in the previous section: *Discount Rates for Commercial Application*.

8.2.2.7 Compliance Date of Standard

DOE calculated the LCC and PBP for all consumers of CWAF as if each were to purchase new equipment in the year that compliance with amended standards is required. EPCA directs DOE to publish a final rule amending the standard for the products covered by today's NOPR not later than 2 years after a notice of proposed rulemaking is issued. (42 U.S.C. 6313(a)(6)(C)(iii)) EPCA also states that amended standards prescribed under this subsection shall apply to products manufactured after a date that is the later of—(I) the date that is 3 years after publication of the final rule establishing a new standard; or (II) the date that is 6 years after the effective date of the current standard for a covered product. (42 U.S.C. 6313(a)(6)(C)(iv)) The date under clause (I), 2019, is later than the date under clause (II). Therefore, for purposes of the LCC and PBP analysis, DOE used 2019 as the beginning of compliance with potential amended standards for CWAF.[f]

8.2.2.8 No-New-Standards Case Distribution of Efficiency Levels

To estimate the market shares of the different efficiency levels in each CWAF equipment class in 2019, DOE developed data on the shares of models in each equipment class that are of the different designs based on the reduced models from August 2015 Air-conditioning, Heating, and Refrigeration Institute (AHRI) certification directory (see appendix 7D for more details about the models used).[17] In addition, for gas-fired CWAF installed outdoors, DOE assumed that condensing level at 92 percent TE would have a 1 percent market share by 2019, because there are some models outside the AHRI certification directory at that efficiency level. Table 8.2.20 shows the no-new-standards case market shares in 2019 for CWAF used in the analysis.

[f] The negotiated compliance date for CWAF standards is January 1, 2023. For all other standard levels, the compliance date would be January 1, 2019. For purposes of the LCC and PBP analysis, DOE used 2019 as the first full year of compliance for all TSLs.

Table 8.2.20 No-New-Standards Case Market Shares in 2019 by Efficiency Level for Commercial Warm Air Furnaces

EL	Design Option	Market Share
Gas-Fired Commercial Warm Air Furnace (Outdoor Units)		
0	80% TE – Baseline	75.5%
1	81% TE – Increased HX Area	23.3%
2	82% TE – Increased HX Area	0.0%
3	92% TE – Condensing (Max Tech)	1.1%
Gas-Fired Commercial Warm Air Furnace (Indoor Units)		
0	80% TE – Baseline	3.5%
1	81% TE – Increased HX Area	93.0%
2	82% TE – Increased HX Area	3.5%
3	92% TE – Condensing (Max Tech)	0.0%
Oil-fired CWAF		
0	81% TE – Baseline	40.0%
1	82% TE – Increased HX Area	60.0%
2	92% TE – Condensing (Max Tech)	0.0%

8.3 PAYBACK PERIOD INPUTS

The PBP is the amount of time it takes the customer to recover the assumed higher purchase cost of more energy-efficient equipment 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. 8.9

Where:

PBP = payback period in years,
ΔIC = difference in the total installed cost between the more efficient standard-level equipment (efficiency levels 1, 2, and so on) and the baseline efficiency equipment, 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, 2019.

8.4 LIFE-CYCLE COSTS AND PAYBACK PERIOD RESULTS

DOE's approach for conducting the LCC and PBP analysis relied on developing building samples that use each of the equipment types. 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 buildings in the sample. LCC and PBP calculations were performed 10,000 times on the building sample established for each unit of commercial equipment. Each LCC and PBP calculation was performed on a single building that was selected from the commercial building sample. The selection of a certain building was based on its sample weight (*i.e.*, how representative a particular building is of other buildings 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 equipment in each equipment class. In contrast, DOE calculated LCC savings relative to the equipment it assigned to the buildings in the no-new-standards case. DOE assigned some buildings equipment in the no-new-standards case 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 equipment. The calculation of average LCC savings excludes buildings with zero LCC savings (no impact from a standard). DOE considered a building to receive no impact at a given efficiency level if DOE assigned it an equipment in the no-new-standards case having an efficiency equal to or greater than the efficiency level in question.

8.4.1 Gas-Fired Commercial Warm Air Furnaces

Table 8.4.1 and Table 8.4.2 summarize the LCC and PBP results for gas-fired CWAF. 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 8.2.2.8). Because some commercial consumers purchase

equipment 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 commercial consumers who are affected by a standard at a given EL. Those who already purchase equipment with efficiency at or above a given EL are not affected. Commercial consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.1 Gas-Fired Commercial Warm Air Furnaces: Average LCC and PBP Results

EL	TE	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	80%	$2,087	$1,789	$28,920	$31,007	NA	23
1	81%	$2,114	$1,770	$28,610	$30,725	1.4	23
2	82%	$2,543	$1,752	$28,311	$30,854	12.3	23
3	92%	$3,840	$1,634	$26,319	$30,159	11.3	23

Table 8.4.2 Gas-Fired Commercial Warm Air Furnaces: LCC Savings Relative to the Base Case Efficiency Distribution

EL	TE	Average LCC Savings* *2014$*	Percent of Consumers that Experience Net Cost
0	80%	NA	--
1	81%	$284	6%
2	82%	$75	58%
3	92%	$766	58%

Figure 8.4.1 shows the range of LCC savings for the efficiency levels considered for gas-fired CWAF. For each standard 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 buildings have LCC 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 standard level.

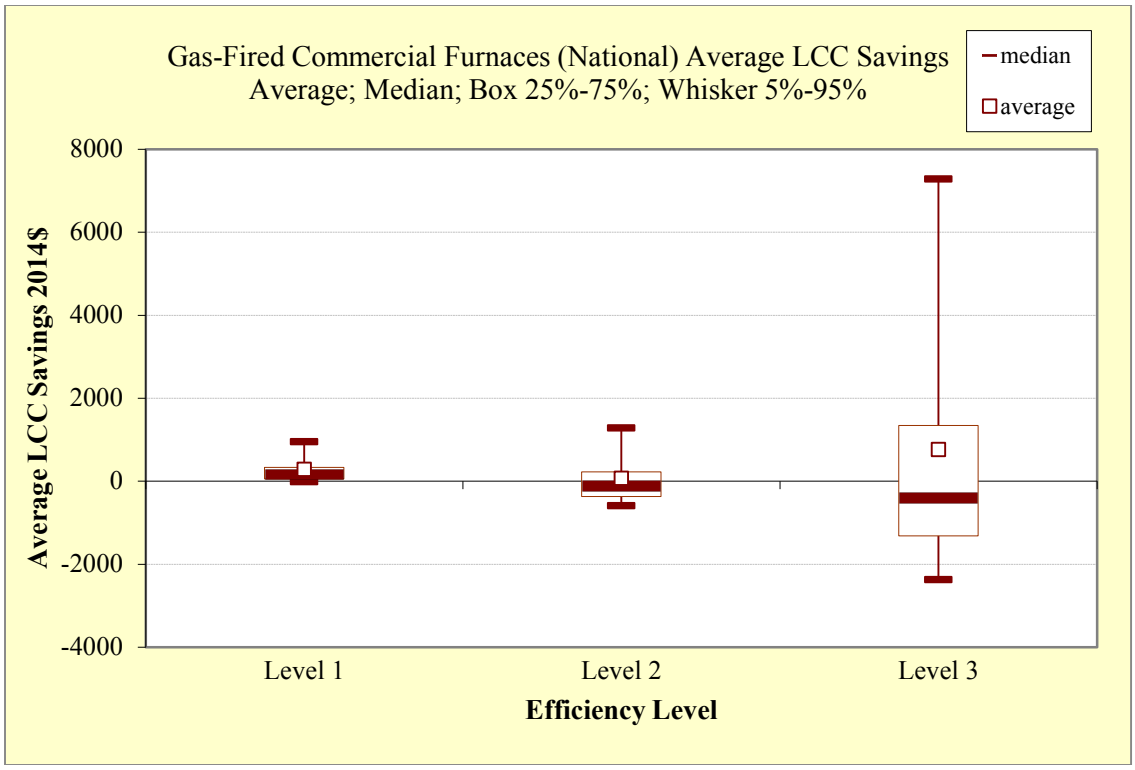

Figure 8.4.1 Distribution of LCC Savings for Gas-Fired Commercial Warm Air Furnaces

8.4.2 Oil-Fired Commercial Warm Air Furnaces

Table 8.4.3 and Table 8.4.4 summarize the LCC and PBP results for commercial oil-fired warm air furnaces. 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 8.2.2.8). Because some commercial consumers purchase equipment 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 commercial consumers who are affected by a standard at a given EL. Those who already purchase equipment with efficiency at or above a given EL are not affected. Commercial consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.3 Oil-Fired Commercial Warm Air Furnaces: LCC and PBP Results

EL	TE	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	81%	$6,357	$3,031	$49,243	$55,601	--	23
1	82%	$6,410	$3,004	$48,782	$55,192	1.9	23
2	92%	$7,861	$2,829	$45,673	$53,534	7.5	23

Table 8.4.4 Gas-Fired Commercial Warm Air Furnaces: LCC Savings Relative to the Base Case Efficiency Distribution

EL	TE	Average LCC Savings* *2014$*	Percent of Consumers that Experience Net Cost
0	81%	NA	--
1	82%	$400	11%
2	92%	$1,817	54%

Figure 8.4.3 shows the range of LCC savings for the efficiency levels considered for oil-fired CWAF. For each standard 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 buildings have LCC 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 standard level.

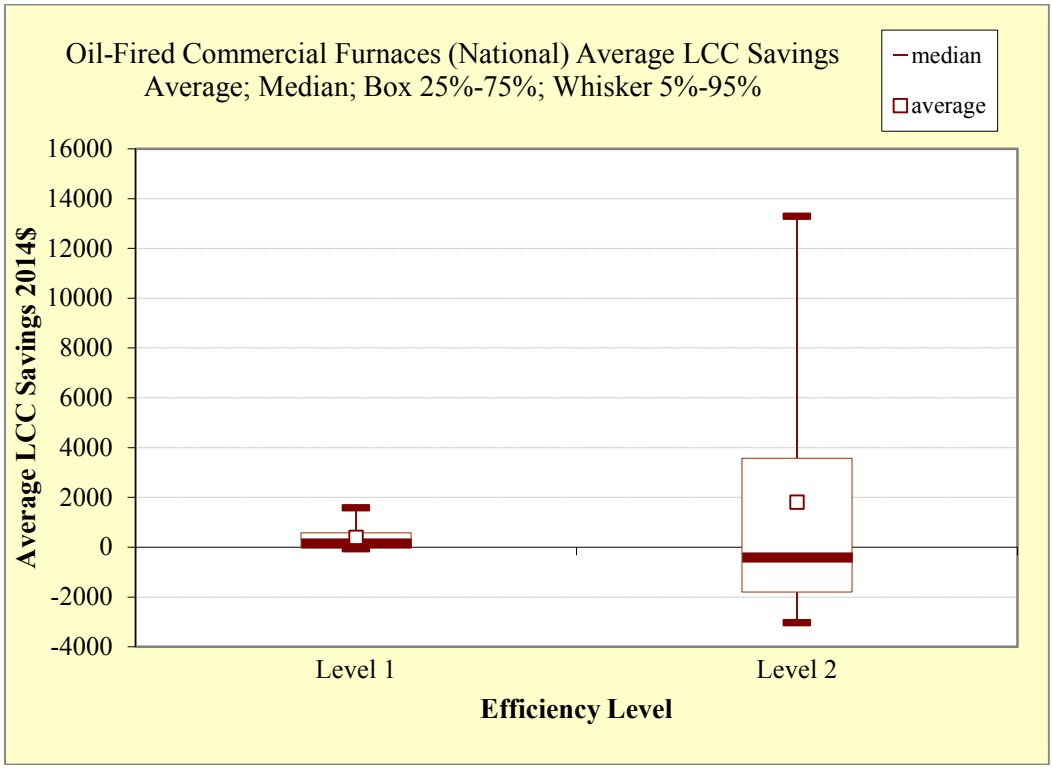

Figure 8.4.2 Distribution of LCC Savings for Oil-Fired Commercial Warm Air Furnaces

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 equipment 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 PBP in section 8.3. Unlike the analysis described in section 8.3, however, the rebuttable PBP is not based on the use of building samples and probability 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.

Other than the use of single-point values, the most notable difference between the distribution PBP and the rebuttable PBP is the latter's reliance on the DOE test procedure to determine an equipment's annual energy consumption.

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 2019.

8.5.2 Results

DOE calculated rebuttable PBPs for each standard level relative to the distribution of equipment energy efficiencies estimated for the no-new-standards case. Table 8.5.1 and Table 8.5.2 present the rebuttable PBPs for CWAF efficiency standards.

Table 8.5.1 Rebuttable Payback Period for Gas-Fired Commercial Warm Air Furnaces

EL	Technology Option	Rebuttable Payback Period *years*
1	81% TE - Increased HX Area	0.95
2	82% TE - Increased HX Area	8.09
3	92% TE - Condensing (Max Tech)	5.90

Table 8.5.2 Rebuttable Payback Period for Oil-Fired Commercial Warm Air Furnaces

EL	Technology Option	Rebuttable Payback Period *years*
1	82% TE - Increased HX Area	1.30
2	92% TE - Condensing (Max Tech)	3.83

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APPENDIX 8A. USER INSTRUCTIONS FOR THE LIFE-CYCLE COST ANALYSIS SPREADSHEET FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

8A.1 USER INSTRUCTIONS 8A-1
8A.2 STARTUP 8A-1
8A.3 DESCRIPTION OF LIFE-CYCLE COST WORKSHEETS 8A-1
8A.3.1 Main LCC worksheet 8A-1
8A.3.2 Analysis input worksheet 8A-4
8A.4 BASIC INSTRUCTIONS FOR OPERATING THE LIFE-CYCLE COST SPREADSHEETS 8A-5

LIST OF FIGURES

Figure 8A.3.1 LCC and Payback Calculation Process 8A-4

APPENDIX 8A. USER INSTRUCTIONS FOR THE LIFE-CYCLE COST ANALYSIS SPREADSHEET FOR COMMERCIAL WARM AIR FURNACES

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) commercial warm air furnaces (CWAF) rulemaking website: www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/70. From that page, follow the links to Notice of Proposed Rule (NOPR) 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 equipment class. Two spreadsheets exist for both CWAF equipment classes: a spreadsheet labeled LCC and another labeled Analysis Inputs. The Analysis Inputs spreadsheet contains the raw data used for the analysis as well the formulas that led to the processed data that are used in the LCC and national impact analysis (NIA). The Analysis Inputs spreadsheet 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. In order to change the input of the main LCC based on updated data from the Analysis Inputs, the user will need to manually copy/paste the data that was modified in the Analysis Inputs 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 Main LCC worksheet

For both CWAF equipment 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

[a] See www.oracle.com/us/products/applications/crystalball/overview/index.html.

contains an area on the extreme left showing variables imported to and exported from the current worksheet. The LCC spreadsheet contains the following worksheets:

Introduction	The *Introduction* worksheet contains an overview of each worksheet and a flow chart of the inputs and outputs of the spreadsheet.
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.
Statistics	The *Statistics* worksheet contains the statistics of key parameters from the outcome of the Monte Carlo simulations for the sample of buildings or households.
LCC&PB Calcs*	The *LCC&PB Calcs* worksheet shows LCC calculation results for different efficiency levels for a single Commercial Building Energy Consumption Survey (CBECS) 2003 building[1] or Residential Energy Consumption Survey (RECS) 2009 household.[2] During a Crystal Ball simulation, the spreadsheet records the LCC and PBP values for every sampled commercial building and residential household.
LCC&PB by Category*	The *LCC&PB by Category* worksheet shows LCC calculation results from LCC&PB Calcs disaggregated by different markets (commercial replacement, commercial new construction, residential replacement, and residential new construction,).
Rebuttable PBP	The *Rebuttable PBP* worksheet contains the total and incremental manufacturer costs, retail prices, the installation costs, the repair and maintenance costs, energy use calculations, and the simple PBP calculations for each efficiency level. DOE's CWAF test procedure is used to calculate parameters used in energy use calculations.
Equip Price*	The *Equip Price* worksheet calculates retail price values used as inputs in the LCC calculations in the *LCC&PB Calcs* 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.
Equip Price Trend*	The *Equip Price Trend* worksheet contains the learning rate values used as inputs in the *Equip Price* worksheet.
Installation Cost*	The *Installation Cost* worksheet calculates the installation cost for each efficiency level. These results are used to calculate the total installed prices of the design options.

Maint & Repair Cost*	The *Maint & Repair Cost* worksheet provides the maintenance and repair costs for each efficiency level. These results are used to determine operating costs for the efficiency levels.
Labor Costs*	The *Labor Cost* worksheet provides the labor cost by region as used to determine the installation and repair/maintenance costs.
Bldg Sample*	The *Building Sample* worksheet contains the CBECS 2003 and RECS 2009 commercial building and residential household data. During a Crystal Ball simulation, DOE uses these commercial building and residential household characteristics to determine the analysis parameters.
Base Case TE*	The *Base Case Thermal Efficiency* worksheet includes the CWAF efficiency distribution in the no-new-standards case in 2019.
TE (Existing)*	The *Existing Thermal Efficiency (existing)* worksheet includes the efficiency of CWAF and commercial unitary air conditioners (CUAC) and commercial unitary heat pumps (CUHP) by equipment class for each year from 1978-2009.
Energy Use*	The *Energy Use* worksheet calculates annual energy use by fuel type, depending on equipment 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 Price*	The *Energy Price* worksheet shows the estimated monthly natural gas, electricity, LPG, and oil prices.
Energy Price Trends*	The *Energy Price Trends* worksheet shows the future price trends of the different heating energy sources. DOE used energy price data and forecasts from the Energy Information Administration's (EIA) *Annual Energy Outlook (AEO) 2015* from 2012-2040 and extrapolated beyond 2040.[3]
Discount Rate*	The *Discount Rate* worksheet contains the distributions of discount rates for the national sample and LCC subgroup analysis.
Lifetime*	The *Lifetime* worksheet contains the distribution of lifetimes for equipment of that equipment class.
Energy Use Adj Factors*	The *Energy Use Adjustment Factors* worksheet contains adjustment factors for normal heating degree days (HDD) and cooling degree days (CDD), as well as building shell efficiency index.
Weather Data*	The *Weather Data* worksheet contains HDD, CDD, heating and cooling outdoor design temperature, and annual mean temperature by the National Oceanic and Atmospheric Administration (NOAA) 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 commercial buildings and residential households 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, efficiency distributions in the no-new-standards case, and extended repair cost for each equipment class and efficiency level. The inputs are presented for replacement and new construction housing markets and commercial and residential sectors. The *LCC Outputs* worksheet also includes energy price information, as well as the fractions of CWAF in the replacement and new construction markets.

* Results displayed in worksheet are for only one sampled building or household, not the entire population.

Figure 8A.3.1 depicts how these various inputs are used to generate the LCC and PBP outputs.

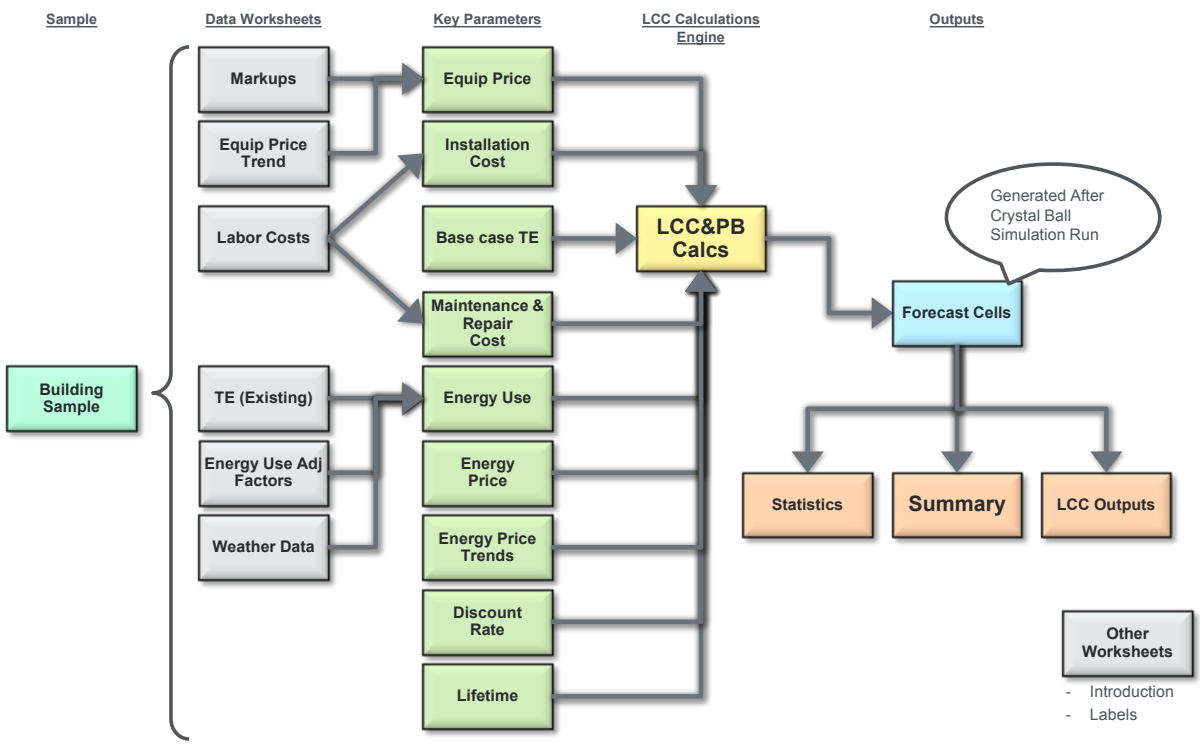

Figure 8A.3.1 LCC and Payback Calculation Process

8A.3.2 Analysis input worksheet

The analysis input spreadsheet contains the following worksheets:

- Markup Input

- Eqp Price Trend
- Labor Cost Data
- CBECS Sample
- RECS Sample
- Sample Stats
- RECS Codebook
- Com Energy Price Input
- Com Energy Price Proc
- Com Energy Price Data
- Com Energy Price (Other)
- Res Energy Price Input
- Res Energy Price Proc
- Res Energy Price Data
- Res Energy Price (Other)
- Energy Price Trends (to LCC)
- Base Case Eff
- Models Directory
- Equip Spec
- Energy Use Adj (Sample Year)
- Energy Use Adj (Current Year)
- Weather Data
- Census Pop. Data
- Definitions

Each of those worksheets is designed to calculate the input that will be used in the corresponding worksheet in the LCC and 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 number of Trials (defaults to "10,000"). To change this value, enter the desired number of trials in the "# of Trials" on the *Summary* worksheet.

3. The user can change the parameters listed under "Scenarios" in the *Summary* worksheet. There are three drop-down boxes and one command button. The default parameters are:

a. 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).

b. Equipment Price Trend: Defaults to “Decreasing (Default).” To change the value, use the drop-down menu (“Decreasing (Default),” “High (Decreasing),” or “Low (Decreasing)”).

c. Subgroup: Defaults to “National.” To change the value, use the drop-down menu (National or Small Business).

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.

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APPENDIX 8B. UNCERTAINTY AND VARIABILITY IN LCC ANALYSIS FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

8B.1 INTRODUCTION 8B-1
8B.2 UNCERTAINTY 8B-1
8B.3 VARIABILITY 8B-1
8B.4 APPROACHES TO UNCERTAINTY AND VARIABILITY 8B-1
8B.5 PROBABILITY ANALYSIS AND THE USE OF CRYSTAL BALL 8B-2

LIST OF FIGURES

Figure 8B.5.1 Normal, Triangular, Uniform, Weibull, and Custom Probability Distributions 8B-3

APPENDIX 8B. UNCERTAINTY AND VARIABILITY IN LCC ANALYSIS FOR COMMERCIAL WARM AIR FURNACES

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). 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 equipment 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 in as much 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:

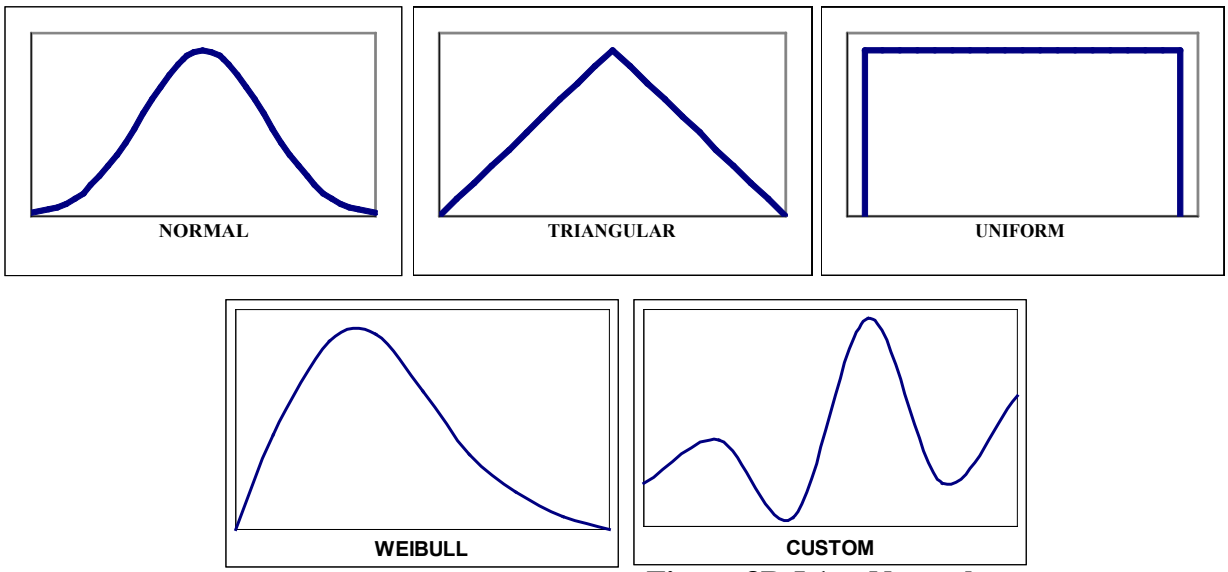

Figure 8B.5.1 Normal, Triangular, Uniform, Weibull, and Custom Probability Distributions

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. ENERGY PRICE CALCULATIONS FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

8C.1 INTRODUCTION 8C-1
8C.2 CBECS/RECS SAMPLE MAPPING PROCESS....8C-1
8C.3 AVERAGE MARGINAL MONTHLY PRICES 8C-1
8C.3.1 Average Annual Prices Determination 8C-1
8C.3.1.1 Annual Electrical Prices.... 8C-1
8C.3.1.2 Annual Natural Gas Prices.... 8C-6
8C.3.1.3 Annual LPG Prices 8C-10
8C.3.1.4 Annual Fuel Oil Prices.... 8C-14
8C.3.2 Monthly Energy Price Factors Determination 8C-18
8C.3.2.1 Monthly Commercial Electricity Price Factor Calculations.... 8C-19
8C.3.2.2 Monthly Residential Electricity Price Factor Calculations.... 8C-21
8C.3.2.3 Monthly Commercial Natural Gas Price Factor Calculations 8C-22
8C.3.2.4 Monthly Residential Natural Gas Price Factor Calculations 8C-25
8C.3.2.5 Monthly Commercial Liquid Petroleum Gas Price Factor Calculations.... 8C-26
8C.3.2.6 Monthly Residential Liquid Petroleum Gas Price Factor Calculations.... 8C-27
8C.3.2.7 Monthly Commercial Oil Price Factor Calculations 8C-29
8C.3.2.8 Monthly Residential Oil Price Factor Calculations 8C-29
8C.3.3 Seasonal Marginal Price Factors Determination....8C-31
8C.3.3.1 Marginal Price Factor Calculation for Electricity and Natural Gas.... 8C-31
8C.3.4 Results....8C-35
8C.4 SAMPLE ENERGY PRICE ADJUSTMENT FACTOR 8C-47
8C.5 ENERGY PRICE TRENDS 8C-48
8C.5.1 Commercial Energy Price Trends....8C-48
8C.5.2 Residential Energy Price Trends....8C-52

LIST OF TABLES

Table 8C.3.1 2013 Monthly Commercial Electricity Prices by State (2013¢/kWh) 8C-2
Table 8C.3.2 2013 Monthly Residential Electricity Prices by State (2013¢/kWh)....8C-3
Table 8C.3.3 Average Commercial Electricity Prices by Region in 2013 ....8C-5
Table 8C.3.4 Average Residential Electricity Prices by Region in 2013 ....8C-6
Table 8C.3.5 2013 Monthly Commercial Natural Gas Prices by State (2013$/tcf) 8C-7
Table 8C.3.6 2013 Monthly Residential Natural Gas Prices by State (2013$/tcf)....8C-8
Table 8C.3.7 Average Commercial Natural Gas Prices by Region in 2013....8C-9
Table 8C.3.8 Average Residential Natural Gas Prices by Region in 2013 ....8C-10
Table 8C.3.9 2013 Commercial Average LPG Prices by State (2013$/MMBtu) 8C-11
Table 8C.3.10 2013 Residential Average LPG Prices by State (2013$/MMBtu) 8C-12

Table 8C.3.11 Average Commercial LPG Prices by Region in 2013 .....8C-13
Table 8C.3.12 Average Residential LPG Prices by Region in 2013 .....8C-14
Table 8C.3.13 2013 Commercial Average Fuel Oil Prices by State (2013$/MMBtu).....8C-15
Table 8C.3.14 2013 Residential Average Fuel Oil Prices by State (2013$/MMBtu) 8C-16
Table 8C.3.15 Average Commercial Fuel Oil Prices by Region in 2013.....8C-17
Table 8C.3.16 Average Residential Fuel Oil Prices by Region in 2013 .....8C-18
Table 8C.3.17 1994-2013 Average Commercial Electricity Prices for New York (nominal cents/kWh).....8C-19
Table 8C.3.18 Monthly Commercial Electricity Price Factors for 1994-2013 for New York 8C-20
Table 8C.3.19 Monthly Commercial Electricity Price Factors 8C-21
Table 8C.3.20 Monthly Residential Electricity Price Factors 8C-22
Table 8C.3.21 1994-2013 Average Commercial Natural Gas Prices for New York ($/tcf).....8C-23
Table 8C.3.22 1994-2013 Monthly Commercial Natural Gas Price Factors for New York 8C-24
Table 8C.3.23 Monthly Commercial Natural Gas Energy Price Factors 8C-25
Table 8C.3.24 Monthly Residential Natural Gas Energy Price Factors 8C-26
Table 8C.3.25 Average LPG Prices for the Northeast (nominal cents/gallon) 8C-27
Table 8C.3.26 Monthly LPG Price Factors for 1995-2009 for the Northeast 8C-28
Table 8C.3.27 Monthly Residential LPG Energy Price Factors.....8C-29
Table 8C.3.28 Average Residential Oil Prices for the Northeast (nominal cents/gallon).....8C-29
Table 8C.3.29 Monthly Oil Price Factors for 1995-2009 for Census Division 1.....8C-30
Table 8C.3.30 Monthly Residential Oil Energy Price Factors 8C-31
Table 8C.3.32 Commercial Marginal Electricity Price Factors using EIA 2004-2013 Data 8C-32
Table 8C.3.33 Residential Marginal Electricity Price Factors using EIA 2004-2013 Data 8C-33
Table 8C.3.34 Commercial Marginal Natural Gas Price Factors using EIA 2002-2011 Data 8C-34
Table 8C.3.35 Residential Marginal Natural Gas Price Factors using EIA 2002-2011 Data 8C-35
Table 8C.3.36 Commercial Average Monthly Electricity Prices for 2013 Using Monthly Price Factors (2014$/kWh) 8C-36
Table 8C.3.37 Residential Average Monthly Electricity Prices for 2013 Using Monthly Price Factors (2014$/kWh) 8C-37
Table 8C.3.38 Commercial Average Monthly Natural Gas Prices for 2013 Using Monthly Price Factors (2014$/MMBtu) 8C-38
Table 8C.3.39 Residential Average Monthly Natural Gas Prices for 2013 Using Monthly Price Factors (2014$/MMBtu) 8C-39
Table 8C.3.40 Commercial Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors (2014$/MMBtu) 8C-40

Table 8C.3.41 Residential Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors (2014$/MMBtu) 8C-41
Table 8C.3.42 Commercial Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors (2014$/MMBtu) 8C-42
Table 8C.3.43 Residential Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors (2014$/MMBtu) 8C-43
Table 8C.3.44 Commercial Monthly LPG Prices for 2013 Using Average Price Factors (2014$/MMBtu) 8C-44
Table 8C.3.45 Residential Monthly LPG Prices for 2013 Using Average Price Factors (2014$/MMBtu) 8C-45
Table 8C.3.46 Comercial Monthly Oil Prices for 2013 Using Average Price Factors (2014$/MMBtu) 8C-46
Table 8C.3.47 Residential Monthly Oil Prices for 2013 Using Average Price Factors (2014$/MMBtu) 8C-47

LIST OF FIGURES

Figure 8C.1.1 Energy Price Calculation Process 8C-1
Figure 8C.3.1 Monthly Commercial Electricity Price Factors for 1994-2013 for New York 8C-20
Figure 8C.3.2 1989-2011 Monthly Commercial Natural Gas Price Factors for New York 8C-24
Figure 8C.3.3 Monthly LPG Factors for 1995-2009 for the Northeast 8C-28
Figure 8C.3.4 Monthly Oil Price Factors for 1995-2009 for Census Division 1 ....8C-30
Figure 8C.5.1 Projected Commercial National Electricity Price Factors 8C-48
Figure 8C.5.2 Projected Commercial Electricity Price Factors by Census Division 8C-49
Figure 8C.5.3 Projected Commercial National Natural Gas Price Factors 8C-49
Figure 8C.5.4 Projected Commercial Natural Gas Price Factors by Census Division 8C-50
Figure 8C.5.5 Projected Commercial National LPG Price Factors 8C-50
Figure 8C.5.6 Projected Commercial LPG Price Factors by Census Division 8C-51
Figure 8C.5.7 Projected Commercial National Fuel Oil Price Factors 8C-51
Figure 8C.5.8 Projected Commercial Fuel Oil Price Factors by Census Division 8C-52
Figure 8C.5.9 Projected Residential National Electricity Price Factors 8C-53
Figure 8C.5.10 Projected Residential Electricity Price Factors by Census Division 8C-53
Figure 8C.5.11 Projected Residential National Natural Gas Price 8C-54
Figure 8C.5.12 Projected Residential Natural Gas Price Factors by Census Division 8C-54
Figure 8C.5.13 Projected Residential National LPG Price Factors 8C-55
Figure 8C.5.14 Projected Residential LPG Price Factors by Census Division 8C-55
Figure 8C.5.15 Projected Residential National Fuel Oil Price Factors 8C-56
Figure 8C.5.16 Projected Residential Fuel Oil Price Factors by Census Division 8C-56

APPENDIX 8C. ENERGY PRICE CALCULATIONS FOR COMMERCIAL WARM AIR FURNACES

8C.1 INTRODUCTION

Figure 8C.1.1 depicts the energy price calculation process, which also encompasses average energy price, seasonal marginal price factor, and monthly price factor calculations.

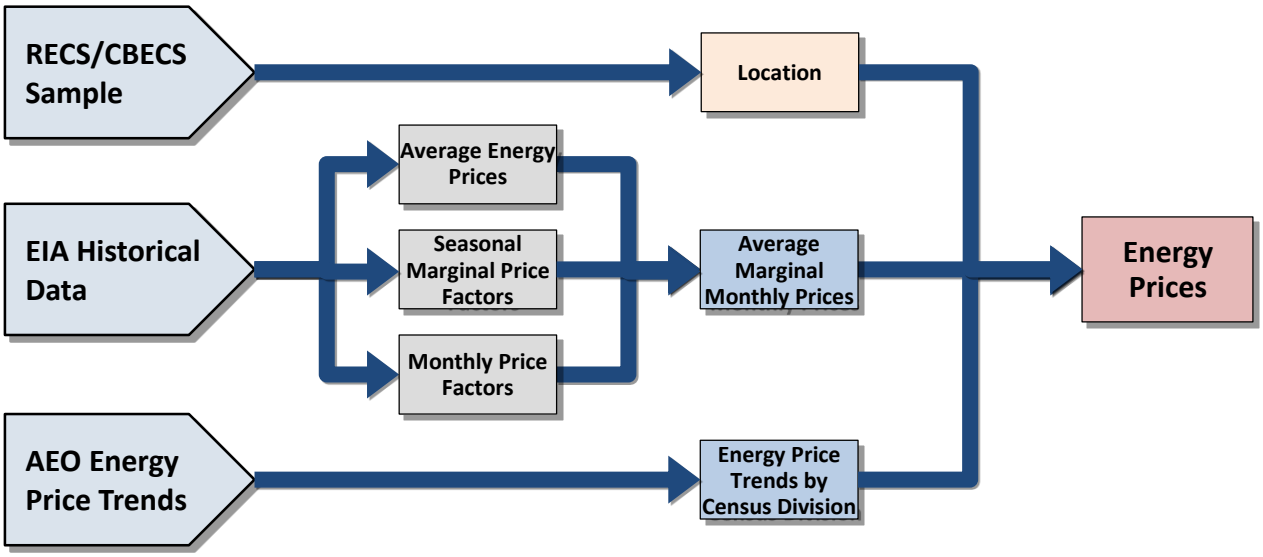

Figure 8C.1.1 Energy Price Calculation Process

8C.2 CBECS/RECS SAMPLE MAPPING PROCESS

To match the state data from EIA to the CBECS 2003 building and RECS 2009 household samples, DOE used the projected 2019 population weights. CBECS 2003 provides 9 census divisions and RECS 2009 utilizes 27 regions (also called reportable domains). 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.

8C.3 AVERAGE MARGINAL MONTHLY PRICES

8C.3.1 Average Annual Prices Determination

8C.3.1.1 Annual Electrical Prices

DOE derived 2013 annual electricity prices from EIA Form 826 data.[1] The EIA Form

826 data include energy prices by State. DOE calculated both commercial and residential annual electricity prices for each geographical area by averaging monthly energy prices by state to get state electricity prices. Table 8C.3.1 shows the monthly commercial electricity prices for each state. Table 8C.3.2 shows the monthly residential electricity prices for each state.

Table 8C.3.1 2013 Monthly Commercial Electricity Prices by State (2013¢/kWh)

Geographical Area	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	9.77
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	10.34
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	14.40
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	9.05
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	7.88
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	11.58
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	9.11
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	14.55
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	10.00
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	11.97
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	9.42
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	9.58
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	35.79
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	6.71
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	7.83
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	9.39
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	7.86
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	9.14
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	8.77
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	8.85
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	12.07
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	10.29
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	13.68
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	10.45
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	8.72
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	9.48
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	7.62
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	9.24
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	7.92
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	8.43
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	13.67
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	12.09
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	9.04
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	14.83
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	8.43
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	7.51
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	9.20
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	6.81
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	8.49

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	9.32
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	12.42
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	9.55
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	7.97
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	10.22
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	7.53
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	14.33
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	7.82
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	7.75
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	8.20
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	10.32
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	8.05

Table 8C.3.2 2013 Monthly Residential Electricity Prices by State (2013¢/kWh)

Geographical Area	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	11.45
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	10.81
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	17.12
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	10.25
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	8.80
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	16.06
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	11.11
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	17.01
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	12.80
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	12.06
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	11.20
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	10.43
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	37.86
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	8.65
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	10.42
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	10.13
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	10.03
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	10.70
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	9.33
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	8.88
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	14.46
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	12.50
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	14.35
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	13.65
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	11.01
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	9.93
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	9.02
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	9.77
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	8.73
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	11.24
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	16.02

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	15.30
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	10.88
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	17.93
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	10.24
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	7.72
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	11.11
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	8.05
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	9.62
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	12.32
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	14.48
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	11.72
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	9.29
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	9.98
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	10.84
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	9.64
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	16.49
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	9.92
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	8.50
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	9.38
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	12.96
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	9.50

DOE calculated both residential and commercial annual electricity prices for each CBECS 2003 or RECS 2009 geographical area by averaging monthly electricity prices by state to get state electricity prices in 2013. For areas with more than one state, DOE weighted each state's average price by its number of households and commercial buildings. All prices in 2013$ were converted to 2014$ using the Consumer Price Index (CPI) to be consistent with the rest of the prices used in the analysis.[a] Table 8C.3.3 shows the average commercial electricity prices for each geographic area. Table 8C.3.4 shows the average residential electricity prices for each geographic area.

[a] www.bls.gov/cpi/

Table 8C.3.3 Average Commercial Electricity Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	New England	$0.14
2	Middle Atlantic	$0.13
3	East North Central	$0.10
4	West North Central	$0.09
5	South Atlantic	$0.10
6	East South Central	$0.10
7	West South Central	$0.08
8	Mountain	$0.09
9	Pacific	$0.14
10	U.S. Average	$0.10

Table 8C.3.4 Average Residential Electricity Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$0.17
2	Massachusetts	$0.16
3	New York	$0.19
4	New Jersey	$0.16
5	Pennsylvania	$0.13
6	Illinois	$0.11
7	Indiana, Ohio	$0.12
8	Michigan	$0.15
9	Wisconsin	$0.14
10	Iowa, Minnesota, North Dakota, South Dakota	$0.11
11	Kansas, Nebraska	$0.11
12	Missouri	$0.11
13	Virginia	$0.11
14	Delaware, District of Columbia, Maryland	$0.13
15	Georgia	$0.12
16	North Carolina, South Carolina	$0.12
17	Florida	$0.11
18	Alabama, Kentucky, Mississippi	$0.11
19	Tennessee	$0.10
20	Arkansas, Louisiana, Oklahoma	$0.10
21	Texas	$0.12
22	Colorado	$0.12
23	Idaho, Montana, Utah, Wyoming	$0.10
24	Arizona	$0.12
25	Nevada, New Mexico	$0.12
26	California	$0.16
27	Oregon, Washington	$0.09
28	Alaska	$0.18
29	Hawaii	$0.38
30	West Virginia	$0.10
31	U.S. Average	$0.12

8C.3.1.2 Annual Natural Gas Prices

DOE obtained the data for natural gas prices from EIA's Natural Gas Navigator,[2] which includes monthly natural gas prices by state for residential, commercial, and industrial customers. Table 8C.3.5 shows the monthly commercial natural gas prices for each state. Table 8C.3.6 shows the monthly residential natural gas prices for each state.

Table 8C.3.5 2013 Monthly Commercial Natural Gas Prices by State (2013$/tcf)

Geographical Area	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	7.75
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	11.91
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	8.76
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	8.39
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	7.37
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	7.52
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	6.59
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	9.66
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	11.13
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	11.18
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	10.46
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	8.86
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	44.55
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	7.07
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	6.82
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	7.07
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	6.66
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	8.22
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	7.30
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	8.45
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	14.39
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	9.38
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	11.36
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	7.67
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	6.45
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	7.83
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	8.17
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	7.54
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	6.35
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	5.96
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	10.92
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	9.57
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	6.22
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	8.35
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	8.78
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	5.99
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	6.18
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	6.72
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	8.03
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	9.61
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	11.21
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	9.46
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	6.37
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	7.61

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	6.38
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	6.95
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	9.00
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	8.60
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	8.69
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	8.20
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	7.21
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	6.34

Table 8C.3.6 2013 Monthly Residential Natural Gas Prices by State (2013$/tcf)

Geographical Area	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	9.15
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	14.28
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	9.07
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	11.09
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	9.33
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	9.50
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	6.76
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	13.23
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	12.32
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	11.44
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	15.42
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	12.59
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	51.66
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	7.78
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	7.00
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	7.57
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	8.04
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	8.69
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	8.03
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	9.05
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	15.33
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	10.63
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	13.22
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	8.68
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	7.37
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	8.13
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	8.78
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	7.56
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	7.32
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	7.63
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	11.99
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	10.83
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	7.56
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	11.27
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	10.89
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	6.49

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	7.61
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	7.66
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	9.86
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	10.46
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	12.66
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	11.05
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	7.46
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	7.92
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	7.70
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	8.10
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	14.73
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	11.10
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	10.51
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	9.16
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	8.30
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	7.00

DOE calculated both residential and commercial annual natural gas prices for each RECS 2009 or CBECS 2003 geographical area by averaging monthly natural gas prices by state to get state natural gas prices in 2013. For areas with more than one state, DOE weighted each state's average price by its number of households and number of commercial buildings. All prices in 2013$ were converted to 2014$ using the CPI to be consistent with the rest of the prices used in the analysis. DOE also used a conversion factor (1.023) to convert from cubic feet of natural gas to MMBtu.[b] Table 8C.3.7 displays the 2011 annual commercial natural gas prices by geographic region. Table 8C.3.8 displays the 2011 annual residential natural gas prices by geographic region.

Table 8C.3.7 Average Commercial Natural Gas Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	New England	$10.91
2	Middle Atlantic	$9.11
3	East North Central	$7.91
4	West North Central	$8.37
5	South Atlantic	$9.98
6	East South Central	$9.69
7	West South Central	$7.96
8	Mountain	$7.83
9	Pacific	$9.03
10	U.S. Average	$8.29

[b] www.eia.gov/tools/faqs/faq.cfm?id=45&t=7

Table 8C.3.8 Average Residential Natural Gas Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$16.23
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	$13.18
8	Michigan	$10.87
9	Wisconsin	$10.16
10	Iowa, Minnesota, North Dakota, South Dakota	$10.48
11	Kansas, Nebraska	$12.91
12	Missouri	$16.10
13	Virginia	$15.02
14	Delaware, District of Columbia, Maryland	$15.03
15	Georgia	$18.30
16	North Carolina, South Carolina	$16.86
17	Florida	$20.36
18	Alabama, Kentucky, Mississippi	$14.99
19	Tennessee	$12.66
20	Arkansas, Louisiana, Oklahoma	$13.89
21	Texas	$14.30
22	Colorado	$9.72
23	Idaho, Montana, Utah, Wyoming	$9.41
24	Arizona	$17.37
25	Nevada, New Mexico	$11.31
26	California	$10.63
27	Oregon, Washington	$12.68
28	Alaska	$9.34
29	Hawaii	$51.02
30	West Virginia	$12.76
31	U.S. Average	$12.35

8C.3.1.3 Annual LPG Prices

DOE collected 2013 average LPG prices from EIA's 2013 State Energy Consumption, Price, and Expenditures Estimates (SEDS).[3] SEDS includes annual LPG prices for residential, commercial, industrial, and transportation consumers by state. Table 8C.3.9 shows the annual commercial LPG prices for each state. Table 8C.3.10 shows the annual residential LPG prices for each state.

Table 8C.3.9 2013 Commercial Average LPG Prices by State (2013$/MMBtu)

Geographical Area	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

Table 8C.3.10 2013 Residential Average LPG Prices by State (2013$/MMBtu)

Geographical Area	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

For areas with more than one state, DOE weighted each state's average price by its number of households and number of commercial buildings. All prices in 2013$ were converted to 2014$ using the CPI to be consistent with the rest of the prices used in the analysis. Table 8C.3.11 shows the average commercial LPG prices for each geographic area. Table 8C.3.12 shows the average residential LPG prices for each geographic area.

Table 8C.3.11 Average Commercial LPG Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	New England	$24.92
2	Middle Atlantic	$24.47
3	East North Central	$21.02
4	West North Central	$20.95
5	South Atlantic	$18.41
6	East South Central	$21.58
7	West South Central	$22.19
8	Mountain	$21.38
9	Pacific	$22.08
10	U.S. Average	$21.57

Table 8C.3.12 Average Residential LPG Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$30.84
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	$26.76
8	Michigan	$24.72
9	Wisconsin	$22.75
10	Iowa, Minnesota, North Dakota, South Dakota	$23.31
11	Kansas, Nebraska	$22.59
12	Missouri	$23.35
13	Virginia	$23.87
14	Delaware, District of Columbia, Maryland	$32.63
15	Georgia	$25.29
16	North Carolina, South Carolina	$26.56
17	Florida	$27.09
18	Alabama, Kentucky, Mississippi	$23.54
19	Tennessee	$28.89
20	Arkansas, Louisiana, Oklahoma	$20.30
21	Texas	$14.53
22	Colorado	$25.21
23	Idaho, Montana, Utah, Wyoming	$24.12
24	Arizona	$29.96
25	Nevada, New Mexico	$25.39
26	California	$28.22
27	Oregon, Washington	$26.10
28	Alaska	$26.49
29	Hawaii	$33.11
30	West Virginia	$31.41
31	U.S. Average	$17.90

8C.3.1.4 Annual Fuel Oil Prices

DOE collected 2013 average fuel oil prices from EIA's SEDS.[3] SEDS includes annual fuel oil prices for residential, commercial, industrial, and transportation consumers by state. Table 8C.3.13 shows the annual commercial fuel oil prices for each state. Table 8C.3.14 shows the annual residential fuel oil prices for each state.

Table 8C.3.13 2013 Commercial Average Fuel Oil Prices by State (2013$/MMBtu)

Geographical Area	Avg. 2013
United States	24.74
Alabama	23.59
Alaska	27.33
Arizona	24.99
Arkansas	24.04
California	25.34
Colorado	23.78
Connecticut	25.58
Delaware	23.5
District of Columbia	24.86
Florida	24.25
Georgia	23.8
Hawaii	24.52
Idaho	26.22
Illinois	24.57
Indiana	24.66
Iowa	24.49
Kansas	24.54
Kentucky	24.49
Louisiana	23.59
Maine	25.02
Maryland	25.67
Massachusetts	25.05
Michigan	24.63
Minnesota	24.69
Mississippi	24.27
Missouri	24.08
Montana	23.11
Nebraska	24.37
Nevada	25.19
New Hampshire	25.63
New Jersey	24.82
New Mexico	23.85
New York	25.01
North Carolina	23.97
North Dakota	24.25
Ohio	24.46
Oklahoma	24.14
Oregon	23.17
Pennsylvania	24.77
Rhode Island	25.49
South Carolina	24.25

South Dakota	24.02
Tennessee	24.72
Texas	24.1
Utah	24.49
Vermont	26.38
Virginia	23.84
Washington	24.85
West Virginia	24.41
Wisconsin	24.42
Wyoming	24.04

Table 8C.3.14 2013 Residential Average Fuel Oil Prices by State (2013$/MMBtu)

Geographical Area	Avg. 2013
United States	28.23
Alabama	25.73
Alaska	27.46
Arizona	29.1
Arkansas	26.23
California	29.51
Colorado	25.09
Connecticut	28.15
Delaware	27.14
District of Columbia	28.75
Florida	28.23
Georgia	27.7
Hawaii	28.55
Idaho	25.85
Illinois	28.3
Indiana	28.5
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	28.1
Nevada	29.33
New Hampshire	26.47

New Jersey	29.04
New Mexico	26.01
New York	28.22
North Carolina	27.9
North Dakota	27.97
Ohio	28.1
Oklahoma	27.83
Oregon	27.45
Pennsylvania	28.77
Rhode Island	28.32
South Carolina	28.23
South Dakota	27.7
Tennessee	28.5
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

For areas with more than one state, DOE weighted each state's average price by its number of households and number of commercial buildings. All prices in 2013$ were converted to 2014$ using the CPI to be consistent with the rest of the prices used in the analysis. Table 8C.3.15 shows the average commercial fuel oil prices for each geographic area. Table 8C.3.16 shows the average residential fuel oil prices for each geographic area.

Table 8C.3.15 Average Commercial Fuel Oil Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	New England	$28.42
2	Middle Atlantic	$29.03
3	East North Central	$28.68
4	West North Central	$28.58
5	South Atlantic	$28.55
6	East South Central	$27.85
7	West South Central	$26.80
8	Mountain	$27.42
9	Pacific	$29.74
10	U.S. Average	$28.69

Table 8C.3.16 Average Residential Fuel Oil Prices by Region in 2013

	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$28.27
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	$28.70
8	Michigan	$28.69
9	Wisconsin	$28.42
10	Iowa, Minnesota, North Dakota, South Dakota	$28.75
11	Kansas, Nebraska	$28.67
12	Missouri	$28.21
13	Virginia	$28.42
14	Delaware, District of Columbia, Maryland	$29.03
15	Georgia	$28.15
16	North Carolina, South Carolina	$28.46
17	Florida	$28.69
18	Alabama, Kentucky, Mississippi	$27.25
19	Tennessee	$28.96
20	Arkansas, Louisiana, Oklahoma	$27.00
21	Texas	$26.72
22	Colorado	$25.50
23	Idaho, Montana, Utah, Wyoming	$25.98
24	Arizona	$29.57
25	Nevada, New Mexico	$28.42
26	California	$29.99
27	Oregon, Washington	$29.07
28	Alaska	$27.91
29	Hawaii	$29.01
30	West Virginia	$28.69
31	U.S. Average	$28.69

8C.3.2 Monthly Energy Price Factors Determination

For CWAF, 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 annual energy prices into monthly energy prices, DOE determined monthly energy price factors.

8C.3.2.1 Monthly Commercial Electricity Price Factor Calculations

DOE collected historical electricity prices from 1994 to 2013 from EIA's Form 826.[1] 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 30 geographical areas described in section 8C.1.

For each geographic region, DOE determined average commercial electricity prices from 1994 to 2013 by weighting the average commercial electricity prices for each state by the number commercial buildings projected in 2019 in each state.

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 8C.3.17 shows the average commercial electricity prices for New York.

Table 8C.3.17 1994-2013 Average Commercial Electricity Prices for New York (nominal cents/kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1993	10.68	10.52	10.64	10.87	11.05	12.31	13.42	13.05	13.42	12.24	10.42	10.71	11.61
1994	10.76	10.75	11.03	11.21	11.59	12.78	13.94	13.03	13.11	12.40	10.93	10.88	11.87
1995	11.06	10.97	11.25	11.33	11.77	12.78	13.77	13.35	13.31	12.69	10.98	11.20	12.04
1996	11.38	11.39	11.41	11.23	11.23	12.69	13.92	13.27	13.23	12.54	11.18	11.33	12.07
1997	11.30	11.02	10.92	11.25	11.28	11.79	12.57	12.25	12.28	11.62	10.22	10.23	11.39
1998	9.96	10.15	11.00	9.01	10.24	9.96	11.85	11.09	11.19	11.57	10.62	10.62	10.60
1999	10.78	11.04	10.95	10.82	11.09	13.17	15.34	14.70	14.11	13.47	12.28	13.30	12.59
2000	12.70	12.31	12.09	11.49	11.88	12.72	14.55	14.74	13.95	13.74	11.66	11.79	12.80
2001	11.45	11.18	11.53	11.66	11.77	12.72	13.89	13.58	13.07	12.92	11.55	11.83	12.26
2002	11.01	11.69	12.43	12.97	12.82	13.44	14.27	14.25	14.10	13.60	12.24	11.88	12.89
2003	11.97	12.07	12.11	11.71	12.17	13.30	14.46	14.45	14.27	13.51	12.61	12.59	12.93
2004	12.71	12.42	12.66	12.91	13.53	14.79	15.37	15.79	15.90	15.72	14.81	14.83	14.29
2005	14.53	14.94	14.26	14.45	14.80	16.10	16.76	17.27	16.60	15.98	14.95	14.71	15.44
2006	14.46	15.56	14.68	15.08	16.05	16.64	16.95	17.20	16.80	15.83	15.48	15.73	15.87
2007	15.64	15.29	15.26	15.70	16.24	18.97	19.44	19.10	18.24	16.45	15.54	15.01	16.74
2008	15.85	15.28	14.06	13.66	14.88	16.21	16.21	16.54	16.60	15.95	14.73	15.52	15.46
2009	15.50	15.54	15.17	15.57	16.39	17.56	18.32	17.13	15.97	16.23	15.92	15.65	16.25
2010	15.40	15.18	14.80	15.09	15.58	17.01	17.26	17.05	16.73	15.71	14.61	14.43	15.74
2011	14.44	14.25	14.30	14.53	14.61	15.93	16.46	15.31	16.22	15.14	14.25	14.48	14.99
2012	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

DOE then calculates monthly commercial energy price factors by dividing the monthly commercial prices by the annual average for each year. Table 8C.3.18 and Figure 8C.3.1 show the results for New York.

Table 8C.3.18 Monthly Commercial Electricity Price Factors for 1994-2013 for New York

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1993	0.92	0.91	0.92	0.94	0.95	1.06	1.16	1.12	1.16	1.05	0.90	0.92
1994	0.91	0.91	0.93	0.94	0.98	1.08	1.17	1.10	1.10	1.05	0.92	0.92
1995	0.92	0.91	0.93	0.94	0.98	1.06	1.14	1.11	1.11	1.05	0.91	0.93
1996	0.94	0.94	0.95	0.93	0.93	1.05	1.15	1.10	1.10	1.04	0.93	0.94
1997	0.99	0.97	0.96	0.99	0.99	1.03	1.10	1.08	1.08	1.02	0.90	0.90
1998	0.94	0.96	1.04	0.85	0.97	0.94	1.12	1.05	1.06	1.09	1.00	1.00
1999	0.86	0.88	0.87	0.86	0.88	1.05	1.22	1.17	1.12	1.07	0.98	1.06
2000	0.99	0.96	0.94	0.90	0.93	0.99	1.14	1.15	1.09	1.07	0.91	0.92
2001	0.93	0.91	0.94	0.95	0.96	1.04	1.13	1.11	1.07	1.05	0.94	0.96
2002	0.85	0.91	0.96	1.01	0.99	1.04	1.11	1.11	1.09	1.05	0.95	0.92
2003	0.93	0.93	0.94	0.91	0.94	1.03	1.12	1.12	1.10	1.04	0.98	0.97
2004	0.89	0.87	0.89	0.90	0.95	1.04	1.08	1.10	1.11	1.10	1.04	1.04
2005	0.94	0.97	0.92	0.94	0.96	1.04	1.09	1.12	1.07	1.03	0.97	0.95
2006	0.91	0.98	0.93	0.95	1.01	1.05	1.07	1.08	1.06	1.00	0.98	0.99
2007	0.93	0.91	0.91	0.94	0.97	1.13	1.16	1.14	1.09	0.98	0.93	0.90
2008	1.03	0.99	0.91	0.88	0.96	1.05	1.05	1.07	1.07	1.03	0.95	1.00
2009	0.95	0.96	0.93	0.96	1.01	1.08	1.13	1.05	0.98	1.00	0.98	0.96
2010	0.98	0.96	0.94	0.96	0.99	1.08	1.10	1.08	1.06	1.00	0.93	0.92
2011	0.96	0.95	0.95	0.97	0.97	1.06	1.10	1.02	1.08	1.01	0.95	0.97
2012	0.97	1.03	0.97	0.92	0.95	1.05	1.10	1.07	1.09	1.00	0.90	0.95

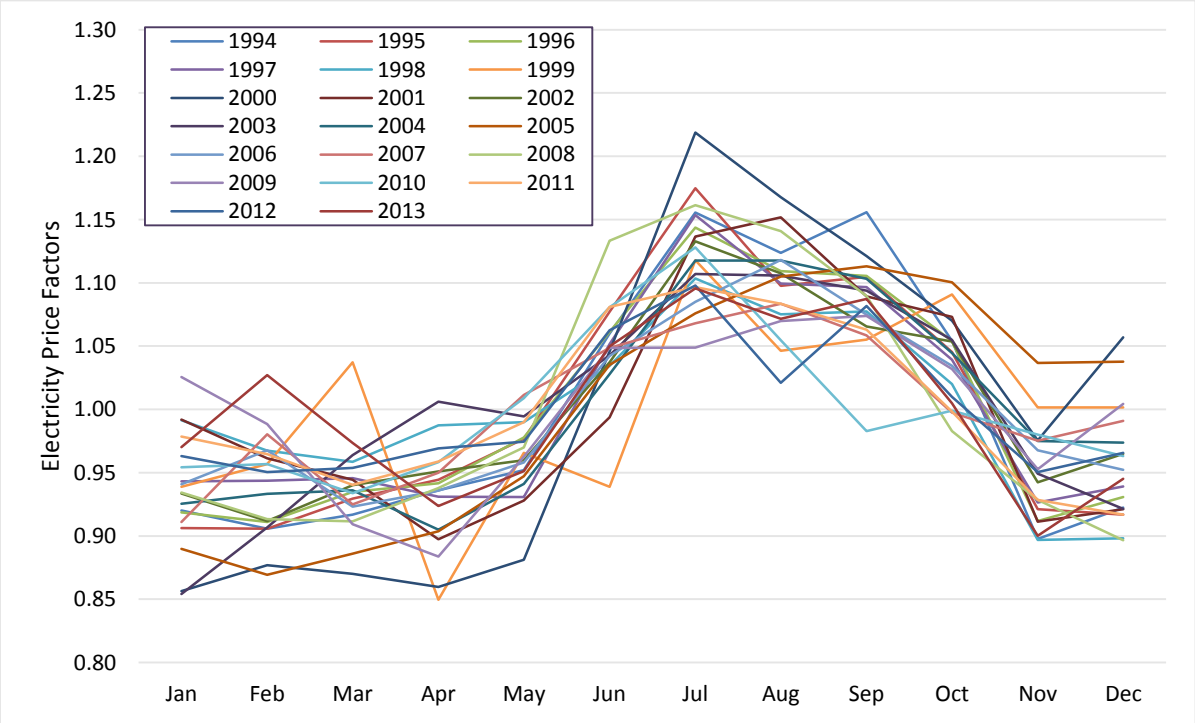

Figure 8C.3.1 Monthly Commercial Electricity Price Factors for 1994-2013 for New York

DOE then averages the monthly energy price factors for 1994 to 2013 to develop an average energy price factor for each month. DOE performs the same calculations for each geographic region to develop the shipment-weighted average monthly energy price factors shown in Table 8C.3.19, which includes the results for New York.

Table 8C.3.19 Monthly Commercial Electricity Price Factors

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.93	0.95	0.93	0.93	0.92	0.98	0.98	0.98	0.99	0.95	0.93	0.95
Middle Atlantic	0.91	0.91	0.91	0.91	0.94	1.00	1.03	1.02	1.01	0.96	0.92	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	0.95	0.92
West North Central	0.87	0.89	0.90	0.91	0.97	1.05	1.07	1.06	1.00	0.92	0.90	0.89
South Atlantic	0.93	0.94	0.95	0.94	0.95	0.96	0.97	0.97	0.97	0.96	0.95	0.94
East South Central	0.93	0.94	0.95	0.95	0.96	0.96	0.95	0.96	0.95	0.96	0.96	0.96
West South Central	0.93	0.95	0.96	0.95	0.95	0.97	0.96	0.97	0.95	0.96	0.94	0.94
Mountain	0.90	0.92	0.92	0.94	0.97	0.99	0.97	0.97	0.98	0.98	0.95	0.92
Pacific	0.87	0.89	0.88	0.89	0.93	1.01	1.06	1.05	1.03	1.00	0.94	0.89
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

8C.3.2.2 Monthly Residential Electricity Price Factor Calculations

DOE collected historical electricity prices from 1994 to 2013 from EIA's Form 826.[1] 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 nine census divisions as described in section 8C.1.

Table 8C.3.20 Monthly Residential Electricity Price Factors

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.93	0.94	0.94	0.95	0.96	0.96	0.95	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	0.97	1.00	1.01	0.98	0.99	1.00	0.99	0.96	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	1.00	0.97	0.93	0.90
Kansas, Nebraska	0.83	0.87	0.89	0.93	0.97	1.04	1.05	1.06	1.05	0.95	0.91	0.87
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	0.87	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	0.90	0.91	0.93	0.96	0.97	0.95	0.97	0.97	0.98	1.00	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	0.93	0.97	0.98	0.98	0.97	0.98	0.98	0.98	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	0.86	0.89	0.92	0.95	0.97	1.00	1.00	1.00	1.01	1.00	0.94	0.89
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	0.91	0.92	0.93	0.96	0.99	1.00	0.99	0.98	0.97	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	0.92	0.94	0.95	0.96	0.96	0.95	0.95	0.95	0.95	0.98	0.97	0.95
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	0.94	0.94	0.94	0.94	0.95	0.96	0.96	0.97	0.97	0.97	0.96
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

8C.3.2.3 Monthly Commercial Natural Gas Price Factor Calculations

DOE collected historical natural gas prices from 1994 to 2013 from the Energy Information Administration's (EIA's) Natural Gas Navigator.[2] The Natural Gas Navigator includes annual and monthly natural gas prices for residential, commercial, and industrial consumers by state. DOE aggregated the data into 30 geographical areas for residential buildings and 9 census division for commercial buildings as described in section 8C.1.

For each geographic area, DOE determined average commercial natural gas prices from 1994 to 2013 by weighting the average commercial natural gas prices for each state by the number commercial buildings projected in 2019 in each state.

Again, as an example for how DOE determines monthly natural gas price factors, the methodology used to determine monthly average price factors can be seen below. Table 8C.3.21 shows the historic average commercial gas prices for New York.

Table 8C.3.21 1994-2013 Average Commercial Natural Gas Prices for New York ($/tcf)

Year*	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1993	6.15	5.90	5.78	6.32	7.18	6.69	6.16	5.94	5.88	5.94	6.15	6.50	6.22
1994	6.56	6.73	6.93	7.07	6.86	6.49	6.16	5.86	6.01	5.84	6.02	6.23	6.40
1995	6.29	6.38	6.10	6.34	6.45	6.43	5.86	5.74	5.73	5.46	5.51	6.16	6.04
1997	8.17	7.61	6.78	6.15	5.95	5.32	4.40	4.86	5.09	5.62	6.58	6.80	6.11
1998	6.67	6.79	6.15	6.55	6.36	5.15	5.49	4.59	5.64	5.40	5.61	6.05	5.87
1999	5.86	6.31	4.58	5.87	5.31	3.99	3.91	3.77	4.24	4.38	5.34	5.90	4.96
2000	10.53	10.86	6.65	7.88	6.72	5.48	4.80	4.94	5.72	6.59	8.73	12.11	7.58
2001	11.96	12.02	10.86	10.38	10.46	9.26	8.19	7.63	7.12	6.47	6.92	7.32	9.05
2002	6.72	6.51	6.30	6.43	6.33	6.37	5.53	5.36	5.55	6.40	6.58	7.55	6.30
2003	7.85	8.34	9.79	9.48	9.27	8.95	8.09	7.62	7.73	7.87	8.42	9.14	8.55
2004	10.22	10.42	10.11	9.49	9.36	9.69	9.47	9.35	8.88	9.23	10.92	11.63	9.90
2005	10.64	10.67	10.65	10.63	10.32	10.02	9.55	10.29	12.28	15.51	16.37	15.10	11.84
2006	15.22	13.39	12.14	11.31	11.11	10.03	9.44	9.97	10.15	9.58	11.05	12.75	11.35
2007	12.09	12.39	12.77	12.15	11.07	11.62	10.72	10.20	9.84	10.83	11.98	12.21	11.49
2008	12.24	12.30	12.84	12.79	13.98	14.58	15.22	13.26	11.76	12.26	12.43	12.87	13.04
2009	12.70	12.09	11.64	10.19	9.22	8.72	8.78	8.46	9.20	9.23	10.32	10.81	10.11
2010	11.85	11.55	11.77	10.96	10.33	10.14	9.68	9.67	10.03	10.31	10.32	10.58	10.60
2011	9.72	9.49	9.87	9.38	9.80	9.03	8.14	8.55	8.63	9.02	9.19	9.19	9.17
2012	8.26	7.76	8.88	7.87	7.56	6.96	6.62	6.50	6.39	7.61	7.72	8.64	7.56

*There are no energy prices for 1996.

DOE then calculates monthly energy price factors for each year by dividing the commercial natural gas prices for each month by the natural gas annual average price for each year. Table 8C.3.22 and Figure 8C.3.2 show the calculated results for New York.

Table 8C.3.22 1994-2013 Monthly Commercial Natural Gas Price Factors for New York

Year*	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1993	1.03	1.05	1.08	1.11	1.07	1.01	0.96	0.92	0.94	0.91	0.94	0.97
1994	1.04	1.06	1.01	1.05	1.07	1.07	0.97	0.95	0.95	0.90	0.91	1.02
1995	1.34	1.25	1.11	1.01	0.97	0.87	0.72	0.80	0.83	0.92	1.08	1.11
1997	1.14	1.16	1.05	1.12	1.08	0.88	0.94	0.78	0.96	0.92	0.96	1.03
1998	1.18	1.27	0.92	1.18	1.07	0.81	0.79	0.76	0.86	0.88	1.08	1.19
1999	1.39	1.43	0.88	1.04	0.89	0.72	0.63	0.65	0.75	0.87	1.15	1.60
2000	1.32	1.33	1.20	1.15	1.16	1.02	0.91	0.84	0.79	0.71	0.76	0.81
2001	1.07	1.03	1.00	1.02	1.00	1.01	0.88	0.85	0.88	1.02	1.04	1.20
2002	0.92	0.98	1.15	1.11	1.08	1.05	0.95	0.89	0.90	0.92	0.99	1.07
2003	1.03	1.05	1.02	0.96	0.95	0.98	0.96	0.94	0.90	0.93	1.10	1.18
2004	0.90	0.90	0.90	0.90	0.87	0.85	0.81	0.87	1.04	1.31	1.38	1.28
2005	1.34	1.18	1.07	1.00	0.98	0.88	0.83	0.88	0.89	0.84	0.97	1.12
2006	1.05	1.08	1.11	1.06	0.96	1.01	0.93	0.89	0.86	0.94	1.04	1.06
2007	0.94	0.94	0.98	0.98	1.07	1.12	1.17	1.02	0.90	0.94	0.95	0.99
2008	1.26	1.20	1.15	1.01	0.91	0.86	0.87	0.84	0.91	0.91	1.02	1.07
2009	1.12	1.09	1.11	1.03	0.97	0.96	0.91	0.91	0.95	0.97	0.97	1.00
2010	1.06	1.04	1.08	1.02	1.07	0.99	0.89	0.93	0.94	0.98	1.00	1.00
2011	1.09	1.03	1.17	1.04	1.00	0.92	0.88	0.86	0.84	1.01	1.02	1.14
2012	1.06	1.07	1.06	1.06	1.06	1.00	0.90	0.91	0.95	1.00	0.97	0.97

*There are no energy prices for 1996.

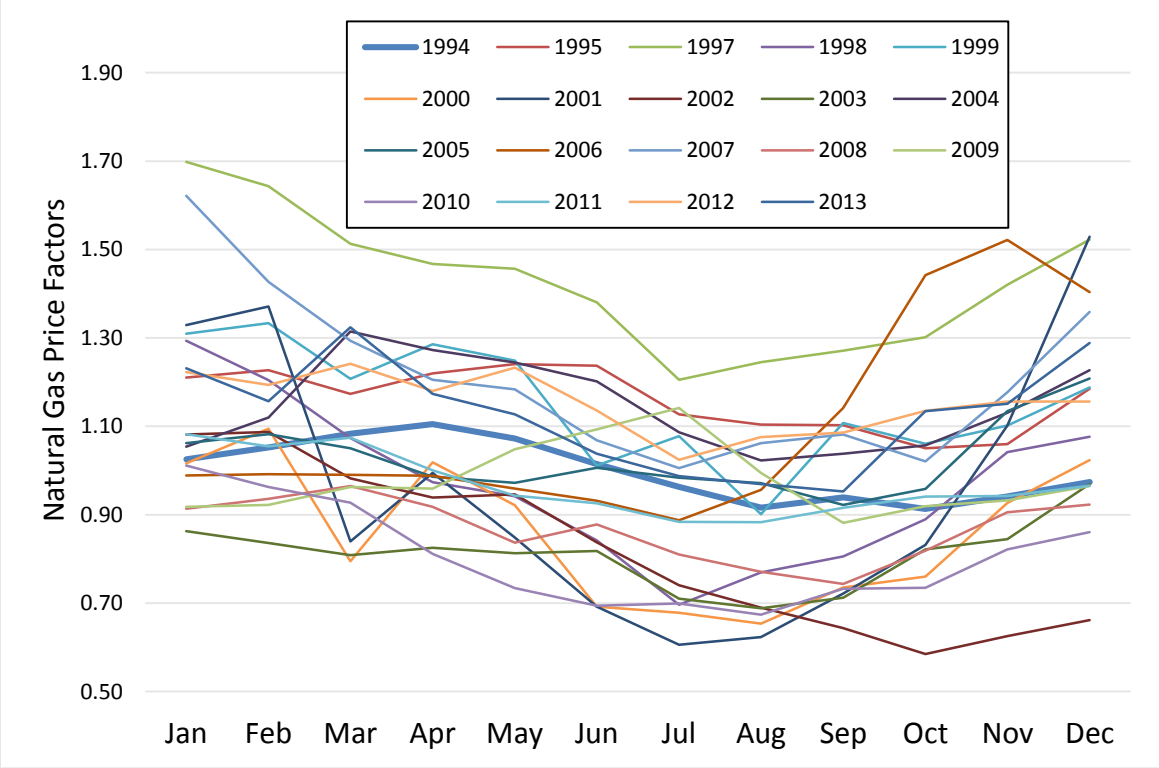

Figure 8C.3.2 1989-2011 Monthly Commercial Natural Gas Price Factors for New York

DOE then averages the monthly energy price factors for 1994 to 2013 to develop an average energy price factor for each month. DOE performs the same calculations for each geographic area to develop the shipment-weighted average monthly energy price factors shown in Table 8C.3.23, which also includes the monthly energy price factor results calculated for New York.

Table 8C.3.23 Monthly Commercial Natural Gas Energy Price Factors

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	1.00	1.01	1.00	1.00	0.92	0.90	0.92	0.91	0.90	0.88	0.97	1.02
Middle Atlantic	1.02	1.00	0.98	0.96	0.95	0.94	0.92	0.89	0.90	0.91	0.96	1.00
East North Central	0.89	0.88	0.89	0.92	0.97	1.04	1.07	1.06	1.00	0.91	0.90	0.89
West North Central	0.93	0.92	0.91	0.91	0.95	0.99	1.02	1.03	0.99	0.93	0.93	0.93
South Atlantic	0.93	0.94	0.94	0.94	0.95	0.97	0.99	0.97	0.96	0.95	0.94	0.95
East South Central	0.92	0.92	0.92	0.94	0.95	0.97	0.98	0.98	0.97	0.97	0.96	0.95
West South Central	0.95	0.94	0.90	0.92	0.96	0.96	0.97	0.95	0.96	0.98	0.99	0.96
Mountain	0.92	0.93	0.93	0.93	0.94	0.96	0.99	1.01	0.99	0.96	0.95	0.93
Pacific	1.01	1.00	0.97	0.95	0.91	0.94	0.93	0.94	0.92	0.92	0.95	1.00
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

8C.3.2.4 Monthly Residential Natural Gas Price Factor Calculations

DOE collected historical natural gas prices from 1994 to 2013 from the Energy Information Administration's (EIA's) Natural Gas Navigator.[2] The Natural Gas Navigator includes annual and monthly natural gas prices for residential, commercial, and industrial consumers by state. DOE aggregated the 30 geographical areas for residential buildings and nine census divisions for commercial buildings as described in chapter 8.

For each geographic area, DOE determined average residential natural gas prices from 1994 to 2013 by weighting the average residential natural gas prices for each state by the number of households projected in 2019 in each state.

Table 8C.3.24 Monthly Residential Natural Gas Energy Price Factors

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.85	0.86	0.86	0.88	0.92	1.00	1.09	1.11	1.08	0.97	0.91	0.88
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	0.76	0.77	0.80	0.86	0.97	1.13	1.23	1.24	1.16	0.92	0.80	0.78
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	0.79	0.81	0.83	0.94	1.11	1.20	1.23	1.15	0.91	0.85	0.81
Kansas, Nebraska	0.75	0.76	0.76	0.83	0.93	1.11	1.19	1.25	1.22	1.04	0.83	0.77
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	0.78	0.77	0.79	0.87	0.99	1.11	1.19	1.19	1.16	0.96	0.83	0.79
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	0.74	0.77	0.83	0.96	1.14	1.20	1.25	1.20	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	0.76	0.76	0.79	0.87	0.99	1.11	1.14	1.16	1.14	1.03	0.87	0.81
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	0.73	0.73	0.75	0.83	0.98	1.09	1.17	1.20	1.17	1.09	0.91	0.77
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	0.88	0.88	0.90	0.87	0.92	0.99	1.08	1.12	1.05	0.92	0.91	0.90
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	0.76	0.78	0.80	0.87	0.99	1.13	1.14	1.18	1.14	1.01	0.85	0.77
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	0.89	0.93	0.99	1.07	1.12	1.08	0.97	0.91	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

8C.3.2.5 Monthly Commercial Liquid Petroleum Gas Price Factor Calculations

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[4] as the residential LPG price factors (see section 8C.3.2.6).

8C.3.2.6 Monthly Residential Liquid Petroleum Gas Price Factor Calculations

DOE collected historical liquid petroleum gas (LPG) prices from 1995 to 2009 from EIA's Short-Term Energy Outlook.[4] The Short-Term Energy Outlook includes monthly LPG prices by Census Region (Northeast, South, Midwest, and West).[c]

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 8C.3.25 shows the Northeast residential LPG prices from 1995 to 2009.

Table 8C.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 8C.3.26 and Figure 8C.3.3 show the calculated results for the Northeast.

[c] Refer to http://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf.

Table 8C.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

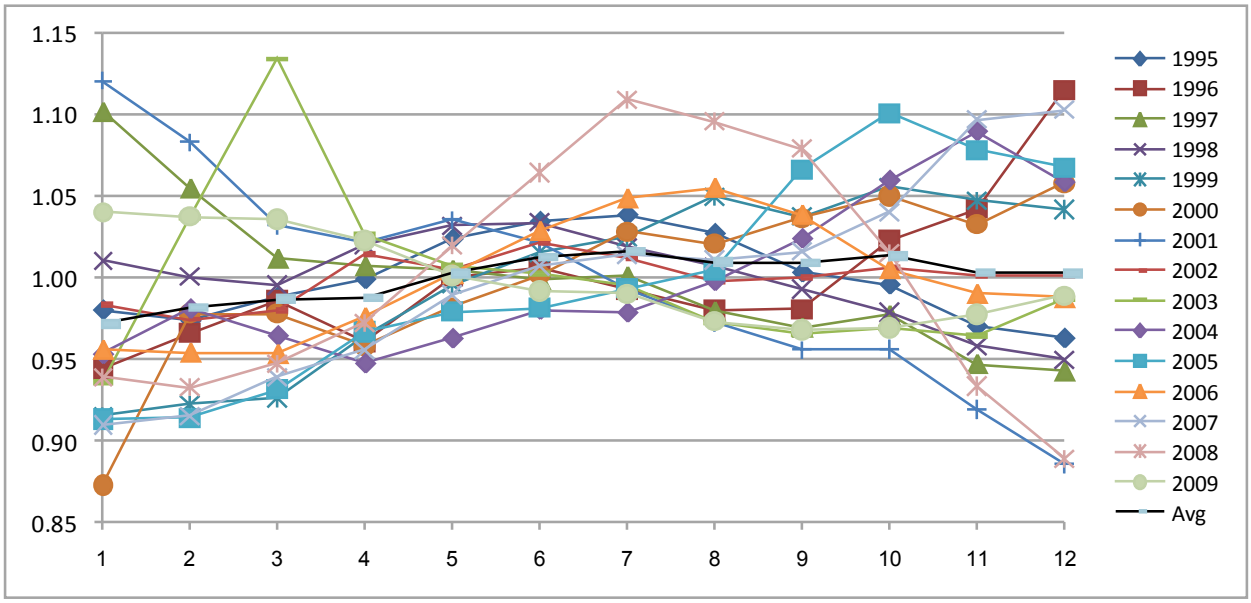

Figure 8C.3.3 Monthly LPG Factors for 1995-2009 for the Northeast

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 average monthly energy price factors shown in Table 8C.3.27, which includes the calculated Northeast region monthly LPG energy price factors from 1995 to 2009.

Table 8C.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

8C.3.2.7 Monthly Commercial Oil Price Factor Calculations

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[4] as the residential fuel oil price factors (see section 8C.3.2.8).

8C.3.2.8 Monthly Residential Oil Price Factor Calculations

DOE collected historical oil prices from 1995 to 2009 from EIA's Short-Term Energy Outlook.[4] The Short-Term Energy Outlook includes monthly oil prices by Census region (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. Table 8C.3.28 shows the Northeast residential oil prices from 1995 to 2009.

Table 8C.3.28 Average Residential Oil Prices for the Northeast (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 8C.3.29 and Figure 8C.3.4 show the calculated results for the Northeast.

Table 8C.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

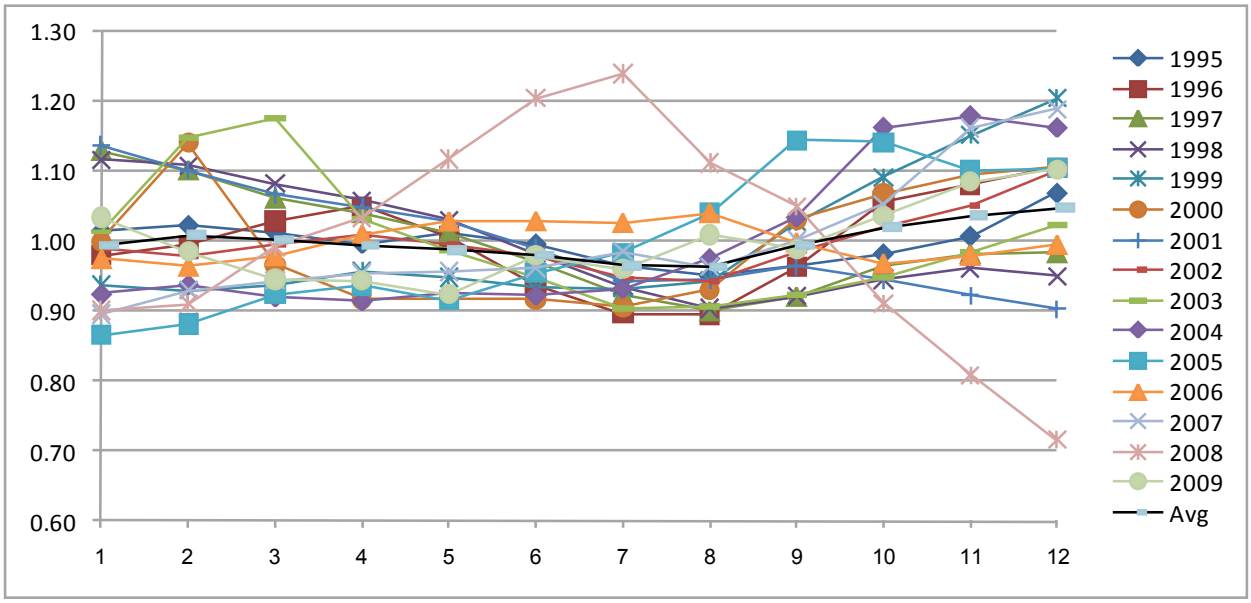

Figure 8C.3.4 Monthly Oil Price Factors for 1995-2009 for Census Division 1

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 average monthly energy price factors shown in Table 8C.3.30 which includes the calculated Northeast region monthly oil energy price factors.

Table 8C.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

8C.3.3 Seasonal Marginal Price Factors Determination

Marginal energy prices are the prices consumers pay for the last unit of energy used. DOE used the marginal energy prices for each building for the cost of saved energy associated with the use of higher-efficiency equipment. 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 possible change to efficiency standards.

EIA provides historical monthly consumption and expenditures by state. This data was used to determine 10 year average marginal prices for the CBECS 2003 and RECS 2009 geographical areas, which are then used to convert average monthly energy prices into marginal monthly energy prices. DOE interpreted the slope of the regression line (consumption vs. expenditures) for each state as the marginal energy price for that state. Because CWAF operate during both the heating and the cooling season, DOE determined summer and winter marginal price factors.

For oil-fired CWAF, DOE used the average oil prices for each building for both base case equipment and higher-efficiency equipment, as the data necessary for estimating marginal prices were not available. DOE used the same method for LPG-fired equipment.

8C.3.3.1 Marginal Price Factor Calculation for Electricity and Natural Gas

EIA provides historical monthly consumption and expenditures by state. This data was used to determine 10 year average marginal prices for the RECS 2009 geographical areas

Table 8C.3.32 through Table 8C.3.35 show the resulting marginal electricity and natural gas marginal price factors.

Table 8C.3.32 Commercial Marginal Electricity Price Factors using EIA 2004-2013 Data

Geographical Area	Summer	Winter
New England	1.12	0.93
Middle Atlantic	1.44	0.95
East North Central	1.10	0.75
West North Central	1.59	0.66
South Atlantic	1.09	0.87
East South Central	1.04	0.81
West South Central	1.14	0.80
Mountain	1.16	1.04
Pacific	1.64	0.82
United States	1.34	0.80

Table 8C.3.33 Residential Marginal Electricity Price Factors using EIA 2004-2013 Data

Geographical Area	Summer	Winter
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.94	1.00
Massachusetts	0.95	1.04
New York	1.14	0.91
New Jersey	1.20	0.99
Pennsylvania	1.07	0.83
Illinois	0.96	0.71
Indiana, Ohio	1.02	0.75
Michigan	1.13	0.96
Wisconsin	1.02	0.89
Iowa, Minnesota, North Dakota, South Dakota	1.07	0.84
Kansas, Nebraska	1.17	0.74
Missouri	1.23	0.76
Virginia	1.08	0.83
Delaware, District of Columbia, Maryland	1.14	0.91
Georgia	1.18	0.85
North Carolina, South Carolina	0.97	0.83
Florida	1.02	0.94
Alabama, Kentucky, Mississippi	1.00	0.83
Tennessee	0.94	0.86
Arkansas, Louisiana, Oklahoma	1.03	0.75
Texas	1.04	0.91
Colorado	1.11	0.80
Idaho, Montana, Utah, Wyoming	1.12	0.94
Arizona	1.05	0.84
Nevada, New Mexico	1.05	0.88
California	1.20	1.12
Oregon, Washington	0.88	0.94
Alaska	0.86	0.90
Hawaii	1.36	0.96
West Virginia	0.93	0.85
United States	1.07	0.85

Table 8C.3.34 Commercial Marginal Natural Gas Price Factors using EIA 2002-2011 Data

Geographical Area	Summer	Winter
New England	1.02	1.00
Middle Atlantic	1.01	0.99
East North Central	0.80	0.99
West North Central	0.83	0.99
South Atlantic	0.90	0.96
East South Central	0.91	0.95
West South Central	0.73	0.92
Mountain	0.90	0.97
Pacific	0.90	1.19
United States	0.90	0.99

Table 8C.3.35 Residential Marginal Natural Gas Price Factors using EIA 2002-2011 Data

Geographical Area	Summer	Winter
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.81	0.93
Massachusetts	0.88	1.04
New York	0.73	0.89
New Jersey	0.83	0.98
Pennsylvania	0.71	0.93
Illinois	0.66	0.96
Indiana, Ohio	0.69	0.91
Michigan	0.78	0.97
Wisconsin	0.79	0.98
Iowa, Minnesota, North Dakota, South Dakota	0.71	0.97
Kansas, Nebraska	0.67	0.94
Missouri	0.57	0.81
Virginia	0.67	0.95
Delaware, District of Columbia, Maryland	0.68	0.93
Georgia	0.55	0.87
North Carolina, South Carolina	0.64	0.92
Florida	0.64	0.81
Alabama, Kentucky, Mississippi	0.72	0.87
Tennessee	0.73	0.93
Arkansas, Louisiana, Oklahoma	0.63	0.83
Texas	0.59	0.84
Colorado	0.68	0.90
Idaho, Montana, Utah, Wyoming	0.85	0.95
Arizona	0.64	0.85
Nevada, New Mexico	0.70	0.89
California	0.83	1.08
Oregon, Washington	0.84	0.94
Alaska	0.87	0.98
Hawaii	0.77	1.02
West Virginia	0.78	0.96
United States	0.72	0.94

8C.3.4 Results

DOE applied the regional monthly energy price factors to develop residential and commercial monthly energy prices for 2013 for electricity and natural gas (Table 8C.3.36 through Table 8C.3.39). Each geographical area was matched with the appropriate Census Region.

Table 8C.3.36 Commercial Average Monthly Electricity Prices for 2013 Using Monthly Price Factors (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.13	0.13	0.14
Middle Atlantic	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.12	0.12
East North Central	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.09	0.09	0.09
West North Central	0.08	0.08	0.08	0.08	0.09	0.10	0.10	0.10	0.09	0.08	0.08	0.08
South Atlantic	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
East South Central	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.10	0.09	0.10	0.10	0.10
West South Central	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Mountain	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Pacific	0.12	0.12	0.12	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.12
United States	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10

Table 8C.3.37 Residential Average Monthly Electricity Prices for 2013 Using Monthly Price Factors (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16
Massachusetts	0.15	0.15	0.15	0.15	0.15	0.16	0.15	0.15	0.15	0.15	0.15	0.15
New York	0.17	0.17	0.17	0.17	0.18	0.18	0.19	0.19	0.19	0.18	0.18	0.17
New Jersey	0.15	0.15	0.15	0.15	0.16	0.17	0.17	0.17	0.17	0.16	0.16	0.16
Pennsylvania	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.13	0.13	0.13	0.12
Illinois	0.10	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11
Indiana, Ohio	0.10	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11
Michigan	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.14	0.14	0.14
Wisconsin	0.13	0.13	0.13	0.13	0.14	0.14	0.13	0.13	0.14	0.14	0.13	0.13
Iowa, Minnesota, North Dakota, South Dakota	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.11	0.11	0.10
Kansas, Nebraska	0.10	0.10	0.10	0.11	0.11	0.12	0.12	0.12	0.12	0.11	0.10	0.10
Missouri	0.09	0.09	0.09	0.10	0.11	0.12	0.12	0.12	0.11	0.10	0.10	0.09
Virginia	0.10	0.10	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11	0.10
Delaware, District of Columbia, Maryland	0.12	0.12	0.12	0.12	0.14	0.15	0.15	0.15	0.14	0.13	0.12	0.12
Georgia	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.13	0.12	0.11	0.11	0.10
North Carolina, South Carolina	0.11	0.11	0.11	0.11	0.12	0.11	0.12	0.12	0.12	0.12	0.11	0.11
Florida	0.11	0.11	0.12	0.12	0.12	0.11	0.12	0.12	0.12	0.12	0.12	0.12
Alabama, Kentucky, Mississippi	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10
Tennessee	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.10
Arkansas, Louisiana, Oklahoma	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.09	0.09
Texas	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
Colorado	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11
Idaho, Montana, Utah, Wyoming	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Arizona	0.10	0.10	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11
Nevada, New Mexico	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
California	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.15	0.15	0.16
Oregon, Washington	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Alaska	0.17	0.17	0.18	0.18	0.19	0.19	0.19	0.19	0.18	0.18	0.18	0.18
Hawaii	0.36	0.37	0.37	0.37	0.38	0.38	0.38	0.39	0.39	0.39	0.39	0.39
West Virginia	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.10	0.10
United States	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.11

Table 8C.3.38 Commercial Average Monthly Natural Gas Prices for 2013 Using Monthly Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	10.9	11.0	11.0	10.9	10.0	9.8	10.0	9.9	9.8	9.6	10.6	11.1
Middle Atlantic	9.3	9.1	8.9	8.7	8.7	8.6	8.3	8.1	8.2	8.3	8.7	9.1
East North Central	7.0	7.0	7.1	7.2	7.7	8.2	8.5	8.4	7.9	7.2	7.1	7.1
West North Central	7.8	7.7	7.6	7.6	8.0	8.3	8.5	8.6	8.3	7.8	7.8	7.7
South Atlantic	9.3	9.4	9.4	9.3	9.5	9.7	9.8	9.7	9.6	9.5	9.4	9.4
East South Central	9.0	8.9	8.9	9.1	9.2	9.4	9.5	9.5	9.4	9.4	9.3	9.2
West South Central	7.5	7.5	7.2	7.3	7.6	7.7	7.7	7.6	7.7	7.8	7.9	7.6
Mountain	7.2	7.3	7.3	7.2	7.4	7.5	7.7	7.9	7.7	7.5	7.5	7.3
Pacific	9.1	9.0	8.8	8.5	8.2	8.5	8.4	8.5	8.3	8.3	8.6	9.0
United States	7.9	7.9	7.8	7.8	7.9	8.0	8.0	7.9	7.9	7.7	7.9	7.9

Table 8C.3.39 Residential Average Monthly Natural Gas Prices for 2013 Using Monthly Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	13.8	13.9	14.0	14.3	15.0	16.2	17.8	18.1	17.6	15.7	14.8	14.4
Massachusetts	13.8	13.8	13.6	14.0	13.3	13.6	15.0	15.8	15.2	13.2	14.1	14.0
New York	12.8	12.6	12.8	13.3	14.9	17.0	17.9	16.8	16.5	14.5	12.8	12.0
New Jersey	10.6	10.5	10.6	10.8	11.4	12.6	13.1	13.0	12.9	11.9	11.2	10.8
Pennsylvania	11.4	11.5	11.7	12.2	13.8	16.0	17.7	18.2	17.2	14.1	12.3	11.7
Illinois	8.4	8.4	8.5	9.0	11.0	12.7	13.7	13.8	12.9	10.0	8.9	8.3
Indiana, Ohio	10.1	10.2	10.5	11.4	12.8	14.9	16.2	16.4	15.3	12.1	10.5	10.3
Michigan	8.6	8.6	8.7	9.2	10.3	11.7	13.0	13.4	12.4	10.2	9.3	8.9
Wisconsin	9.2	9.0	9.1	9.3	9.2	10.7	11.1	11.3	10.3	8.4	9.4	9.1
Iowa, Minnesota, North Dakota, South Dakota	8.5	8.3	8.5	8.7	9.8	11.6	12.6	12.9	12.0	9.5	8.9	8.4
Kansas, Nebraska	9.7	9.8	9.8	10.7	12.1	14.3	15.4	16.2	15.7	13.4	10.7	9.9
Missouri	11.1	11.1	11.2	12.6	14.6	18.1	20.7	21.9	20.4	17.2	13.4	11.8
Virginia	11.7	11.2	11.1	12.4	14.7	17.1	18.6	18.2	18.2	14.7	12.0	11.6
Delaware, District of Columbia, Maryland	11.7	11.6	11.9	13.0	14.9	16.8	17.9	17.9	17.5	14.4	12.5	11.9
Georgia	12.4	13.3	13.8	15.4	19.2	21.6	22.7	22.5	21.9	18.8	14.2	13.3
North Carolina, South Carolina	12.6	12.5	12.9	14.0	16.2	19.2	20.3	21.0	20.2	16.7	13.7	13.3
Florida	15.7	16.1	17.2	18.2	19.8	21.1	21.7	22.2	21.9	21.5	19.7	17.5
Alabama, Kentucky, Mississippi	11.4	11.4	11.8	13.0	14.9	16.6	17.1	17.4	17.0	15.4	13.1	12.1
Tennessee	9.8	9.9	9.9	10.8	11.9	13.8	14.7	15.1	14.5	13.1	11.0	10.3
Arkansas, Louisiana, Oklahoma	10.2	10.2	10.4	11.5	13.7	15.2	16.2	16.7	16.2	15.1	12.6	10.7
Texas	10.3	10.4	10.7	12.4	14.2	16.1	16.6	17.1	16.9	15.3	12.5	10.8
Colorado	7.4	7.5	7.8	8.0	9.0	11.5	11.6	12.3	11.3	8.9	8.1	7.6
Idaho, Montana, Utah, Wyoming	8.3	8.3	8.5	8.2	8.6	9.3	10.1	10.6	9.9	8.7	8.6	8.4
Arizona	12.6	13.0	13.5	14.9	16.7	18.5	20.2	20.8	20.2	18.7	15.8	13.6
Nevada, New Mexico	8.6	8.8	9.1	9.8	11.2	12.8	12.8	13.3	12.9	11.4	9.6	8.7
California	10.1	10.0	9.6	9.7	10.1	10.6	10.7	10.5	10.2	10.3	9.9	9.9
Oregon, Washington	10.8	11.0	11.0	11.3	11.8	12.5	13.6	14.1	13.7	12.3	11.5	11.2
Alaska	8.4	8.4	8.5	8.6	9.0	9.3	10.0	9.8	9.1	8.6	8.4	8.7
Hawaii	46.0	47.3	47.3	47.3	47.8	48.3	49.5	50.6	50.5	50.3	49.6	48.7
West Virginia	10.0	10.1	10.2	10.6	11.8	14.3	16.0	15.8	14.4	11.7	10.7	10.3
United States	10.0	10.0	10.2	10.7	11.8	13.3	14.1	14.4	13.8	11.8	10.7	10.2

DOE then applied the marginal price factors to the monthly energy prices to develop marginal commercial and residential monthly energy prices for 2013 for electricity and natural gas (Table 8C.3.40-Table 8C.3.43). Each geographical area was matched with the appropriate Census Region.

Table 8C.3.40 Commercial Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.12	0.12	0.12	0.15	0.15	0.16	0.16	0.16	0.16	0.15	0.12	0.13
Middle Atlantic	0.11	0.11	0.11	0.17	0.18	0.19	0.19	0.19	0.19	0.18	0.11	0.11
East North Central	0.07	0.07	0.07	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.07	0.07
West North Central	0.05	0.05	0.05	0.13	0.14	0.15	0.15	0.15	0.14	0.13	0.05	0.05
South Atlantic	0.08	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.08	0.08
East South Central	0.07	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.08	0.08
West South Central	0.06	0.06	0.06	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.06	0.06
Mountain	0.09	0.09	0.09	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
Pacific	0.10	0.10	0.10	0.20	0.21	0.23	0.24	0.23	0.23	0.22	0.10	0.10
United States	0.08	0.08	0.08	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.08	0.08

Table 8C.3.41 Residential Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16
Massachusetts	0.16	0.16	0.16	0.14	0.15	0.15	0.14	0.15	0.15	0.15	0.16	0.16
New York	0.16	0.16	0.16	0.20	0.21	0.21	0.22	0.22	0.22	0.21	0.16	0.16
New Jersey	0.14	0.14	0.14	0.17	0.18	0.19	0.20	0.20	0.19	0.18	0.15	0.15
Pennsylvania	0.10	0.10	0.10	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.10	0.10
Illinois	0.07	0.07	0.07	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.07	0.07
Indiana, Ohio	0.08	0.08	0.08	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.08
Michigan	0.13	0.13	0.13	0.16	0.16	0.16	0.17	0.17	0.16	0.16	0.13	0.13
Wisconsin	0.11	0.12	0.11	0.13	0.14	0.14	0.13	0.13	0.14	0.14	0.12	0.11
Iowa, Minnesota, North Dakota, South Dakota	0.08	0.09	0.09	0.12	0.12	0.13	0.13	0.13	0.12	0.12	0.09	0.09
Kansas, Nebraska	0.07	0.07	0.08	0.12	0.13	0.14	0.14	0.14	0.14	0.13	0.08	0.07
Missouri	0.07	0.07	0.07	0.12	0.14	0.15	0.15	0.15	0.13	0.12	0.07	0.07
Virginia	0.08	0.08	0.08	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.08
Delaware, District of Columbia, Maryland	0.11	0.11	0.11	0.14	0.15	0.16	0.16	0.16	0.16	0.15	0.11	0.11
Georgia	0.08	0.09	0.09	0.13	0.13	0.14	0.14	0.14	0.14	0.13	0.09	0.08
North Carolina, South Carolina	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
Florida	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.10	0.10
Alabama, Kentucky, Mississippi	0.08	0.08	0.08	0.10	0.11	0.11	0.10	0.11	0.11	0.11	0.09	0.08
Tennessee	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08
Arkansas, Louisiana, Oklahoma	0.06	0.06	0.07	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.07	0.06
Texas	0.09	0.09	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.10	0.10
Colorado	0.09	0.09	0.09	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.09	0.09
Idaho, Montana, Utah, Wyoming	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
Arizona	0.08	0.09	0.09	0.12	0.13	0.13	0.13	0.13	0.12	0.12	0.09	0.09
Nevada, New Mexico	0.10	0.10	0.10	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.10	0.10
California	0.17	0.17	0.17	0.18	0.19	0.19	0.20	0.20	0.19	0.18	0.17	0.18
Oregon, Washington	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Alaska	0.15	0.15	0.16	0.15	0.15	0.15	0.16	0.16	0.15	0.15	0.16	0.16
Hawaii	0.33	0.33	0.33	0.47	0.48	0.49	0.49	0.50	0.50	0.50	0.36	0.35
West Virginia	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.08
United States	0.09	0.09	0.10	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.10	0.10

Table 8C.3.42 Commercial Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	10.92	10.95	10.94	11.12	10.27	10.03	10.27	10.15	10.07	9.87	10.59	11.07
Middle Atlantic	9.20	9.07	8.84	8.82	8.76	8.66	8.41	8.19	8.25	8.40	8.66	9.03
East North Central	6.99	6.93	7.00	5.82	6.19	6.59	6.80	6.76	6.37	5.78	7.07	7.02
West North Central	7.67	7.60	7.55	6.35	6.63	6.91	7.10	7.13	6.89	6.45	7.73	7.67
South Atlantic	8.94	8.98	8.97	8.40	8.52	8.72	8.85	8.71	8.66	8.54	9.04	9.06
East South Central	8.48	8.46	8.42	8.25	8.40	8.53	8.61	8.67	8.53	8.55	8.84	8.71
West South Central	6.96	6.87	6.61	5.31	5.56	5.58	5.60	5.51	5.57	5.68	7.29	7.03
Mountain	6.98	7.02	7.04	6.51	6.62	6.76	6.96	7.07	6.94	6.72	7.21	7.06
Pacific	10.79	10.65	10.40	7.72	7.41	7.66	7.60	7.65	7.51	7.51	10.17	10.70
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

Table 8C.3.43 Residential Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	13.8	13.9	14.0	13.4	14.1	15.2	16.6	16.9	16.5	14.7	14.8	14.4
Massachusetts	14.3	14.3	14.2	13.3	12.6	12.9	14.2	15.0	14.5	12.5	14.6	14.5
New York	11.7	11.5	11.7	15.2	17.0	19.4	20.4	19.2	18.8	16.5	11.7	10.9
New Jersey	10.5	10.4	10.4	12.9	13.7	15.1	15.7	15.6	15.4	14.2	11.0	10.7
Pennsylvania	9.4	9.5	9.7	13.1	14.8	17.1	19.0	19.5	18.5	15.1	10.3	9.7
Illinois	5.9	6.0	6.0	8.6	10.5	12.2	13.1	13.2	12.3	9.6	6.3	5.9
Indiana, Ohio	7.5	7.6	7.9	11.6	13.0	15.1	16.5	16.7	15.5	12.3	7.9	7.7
Michigan	8.2	8.3	8.4	10.3	11.6	13.2	14.6	15.1	13.9	11.5	8.9	8.6
Wisconsin	8.2	8.0	8.1	9.4	9.4	10.9	11.3	11.5	10.5	8.6	8.4	8.1
Iowa, Minnesota, North Dakota, South Dakota	7.1	7.0	7.2	9.3	10.5	12.5	13.5	13.9	12.9	10.2	7.5	7.1
Kansas, Nebraska	7.2	7.3	7.3	12.5	14.0	16.7	18.0	18.8	18.3	15.6	8.0	7.4
Missouri	8.5	8.5	8.6	15.5	17.9	22.2	25.4	26.9	25.1	21.2	10.2	9.0
Virginia	9.8	9.4	9.3	13.4	15.9	18.6	20.1	19.8	19.7	16.0	10.0	9.7
Delaware, District of Columbia, Maryland	10.7	10.6	10.8	14.9	17.0	19.2	20.5	20.4	20.0	16.5	11.5	10.9
Georgia	10.5	11.2	11.7	18.2	22.5	25.4	26.7	26.5	25.7	22.1	12.0	11.3
North Carolina, South Carolina	10.4	10.4	10.8	13.7	15.8	18.8	19.8	20.5	19.7	16.3	11.4	11.1
Florida	14.9	15.2	16.2	18.5	20.1	21.4	22.1	22.6	22.3	21.9	18.7	16.6
Alabama, Kentucky, Mississippi	9.4	9.4	9.8	13.0	14.8	16.6	17.1	17.4	17.0	15.4	10.8	10.0
Tennessee	8.4	8.5	8.5	10.2	11.3	13.0	13.9	14.3	13.7	12.4	9.4	8.8
Arkansas, Louisiana, Oklahoma	7.6	7.6	7.8	11.8	14.1	15.6	16.7	17.2	16.7	15.6	9.5	8.0
Texas	9.4	9.4	9.7	12.9	14.7	16.6	17.2	17.7	17.5	15.9	11.3	9.8
Colorado	6.0	6.0	6.2	9.0	10.0	12.7	12.9	13.6	12.6	9.9	6.4	6.1
Idaho, Montana, Utah, Wyoming	7.8	7.8	8.0	9.2	9.6	10.4	11.3	11.8	11.0	9.7	8.1	7.9
Arizona	10.6	11.0	11.4	15.7	17.6	19.5	21.2	21.9	21.2	19.7	13.3	11.4
Nevada, New Mexico	7.6	7.8	8.0	10.2	11.7	13.4	13.4	13.9	13.5	11.9	8.5	7.7
California	11.3	11.1	10.8	11.6	12.2	12.8	12.8	12.6	12.3	12.4	11.1	11.1
Oregon, Washington	10.2	10.3	10.4	9.9	10.4	11.0	12.0	12.4	12.1	10.9	10.8	10.5
Alaska	7.6	7.6	7.6	7.3	7.7	8.0	8.6	8.4	7.8	7.4	7.6	7.8
Hawaii	44.4	45.6	45.6	64.3	65.0	65.7	67.3	68.8	68.6	68.4	47.8	47.0
West Virginia	8.6	8.6	8.7	9.8	10.9	13.3	14.8	14.6	13.3	10.8	9.1	8.8
United States	8.5	8.5	8.6	11.5	12.7	14.3	15.2	15.5	14.8	12.7	9.0	8.6

DOE applied the regional monthly energy price factors to the annual LPG data presented in chapter 8 to develop commercial and residential monthly energy prices for 2013 (Table 8C.3.44 and Table 8C.3.45, respectively). Each geographical area was matched with the appropriate Census Region.

Table 8C.3.44 Commercial Monthly LPG Prices for 2013 Using Average Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	24.22	24.46	24.60	24.61	24.99	25.24	25.32	25.16	25.14	25.26	25.00	24.99
Middle Atlantic	23.78	24.03	24.16	24.17	24.54	24.79	24.87	24.71	24.69	24.81	24.56	24.54
East North Central	21.90	21.89	21.63	21.29	21.03	20.29	19.68	19.63	20.08	20.68	21.62	22.57
West North Central	21.82	21.82	21.55	21.22	20.96	20.22	19.62	19.56	20.01	20.61	21.54	22.50
South Atlantic	19.14	19.19	18.91	18.54	18.25	17.90	17.49	17.16	17.59	18.32	18.89	19.50
East South Central	22.43	22.50	22.16	21.73	21.39	20.99	20.51	20.12	20.62	21.48	22.14	22.86
West South Central	23.07	23.14	22.79	22.35	22.00	21.58	21.09	20.69	21.21	22.09	22.77	23.51
Mountain	22.46	22.50	22.12	21.61	21.09	20.49	19.75	19.50	20.27	21.49	22.18	23.04
Pacific	23.20	23.24	22.84	22.32	21.79	21.16	20.40	20.14	20.94	22.19	22.90	23.80
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 8C.3.45 Residential Monthly LPG Prices for 2013 Using Average Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	30.0	30.3	30.4	30.5	30.9	31.2	31.3	31.1	31.1	31.3	30.9	30.9
Massachusetts	32.1	32.4	32.6	32.6	33.1	33.4	33.5	33.3	33.3	33.4	33.1	33.1
New York	31.2	31.5	31.7	31.7	32.2	32.5	32.6	32.4	32.4	32.6	32.2	32.2
New Jersey	31.8	32.2	32.3	32.4	32.9	33.2	33.3	33.1	33.1	33.2	32.9	32.9
Pennsylvania	29.1	29.4	29.6	29.6	30.1	30.4	30.5	30.3	30.3	30.4	30.1	30.1
Illinois	23.8	23.8	23.5	23.1	22.8	22.0	21.4	21.3	21.8	22.5	23.5	24.5
Indiana, Ohio	27.9	27.9	27.5	27.1	26.8	25.8	25.1	25.0	25.6	26.3	27.5	28.7
Michigan	25.8	25.7	25.4	25.0	24.7	23.9	23.1	23.1	23.6	24.3	25.4	26.5
Wisconsin	23.7	23.7	23.4	23.0	22.8	22.0	21.3	21.2	21.7	22.4	23.4	24.4
Iowa, Minnesota, North Dakota, South Dakota	24.3	24.3	24.0	23.6	23.3	22.5	21.8	21.8	22.3	22.9	24.0	25.0
Kansas, Nebraska	23.5	23.5	23.2	22.9	22.6	21.8	21.2	21.1	21.6	22.2	23.2	24.3
Missouri	24.3	24.3	24.0	23.6	23.4	22.5	21.9	21.8	22.3	23.0	24.0	25.1
Virginia	24.8	24.9	24.5	24.0	23.7	23.2	22.7	22.3	22.8	23.8	24.5	25.3
Delaware, District of Columbia, Maryland	33.9	34.0	33.5	32.9	32.3	31.7	31.0	30.4	31.2	32.5	33.5	34.6
Georgia	26.3	26.4	26.0	25.5	25.1	24.6	24.0	23.6	24.2	25.2	26.0	26.8
North Carolina, South Carolina	27.6	27.7	27.3	26.8	26.3	25.8	25.2	24.8	25.4	26.4	27.3	28.1
Florida	28.2	28.3	27.8	27.3	26.9	26.4	25.7	25.3	25.9	27.0	27.8	28.7
Alabama, Kentucky, Mississippi	24.5	24.5	24.2	23.7	23.3	22.9	22.4	21.9	22.5	23.4	24.2	24.9
Tennessee	30.0	30.1	29.7	29.1	28.6	28.1	27.5	26.9	27.6	28.8	29.6	30.6
Arkansas, Louisiana, Oklahoma	21.1	21.2	20.8	20.4	20.1	19.7	19.3	18.9	19.4	20.2	20.8	21.5
Texas	15.1	15.2	14.9	14.6	14.4	14.1	13.8	13.5	13.9	14.5	14.9	15.4
Colorado	26.5	26.5	26.1	25.5	24.9	24.2	23.3	23.0	23.9	25.3	26.2	27.2
Idaho, Montana, Utah, Wyoming	25.3	25.4	25.0	24.4	23.8	23.1	22.3	22.0	22.9	24.2	25.0	26.0
Arizona	31.5	31.5	31.0	30.3	29.6	28.7	27.7	27.3	28.4	30.1	31.1	32.3
Nevada, New Mexico	26.6	26.7	26.2	25.6	25.0	24.3	23.4	23.1	24.1	25.5	26.3	27.3
California	29.7	29.7	29.2	28.5	27.8	27.1	26.1	25.7	26.8	28.4	29.3	30.4
Oregon, Washington	27.4	27.5	27.0	26.4	25.8	25.0	24.1	23.8	24.8	26.2	27.1	28.1
Alaska	27.8	27.9	27.4	26.8	26.1	25.4	24.5	24.2	25.1	26.6	27.5	28.6
Hawaii	34.8	34.9	34.3	33.5	32.7	31.7	30.6	30.2	31.4	33.3	34.3	35.7
West Virginia	32.7	32.8	32.3	31.6	31.1	30.6	29.9	29.3	30.0	31.3	32.2	33.3
United States	18.3	18.4	18.3	18.2	18.2	17.8	17.0	16.6	17.1	17.7	18.3	18.8

DOE applied the regional monthly energy price factors to the annual oil data presented in chapter 8 to develop commercial and residential monthly energy prices for 2013 (Table 8C.3.46 and Table 8C.3.47, respectively). Each Census Division and Large State was matched with the appropriate Census Region.

Table 8C.3.46 Comercial Monthly Oil Prices for 2013 Using Average Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	28.27	28.68	28.49	28.24	28.07	27.88	27.44	27.40	28.27	28.99	29.47	29.79
Middle Atlantic	28.88	29.30	29.10	28.85	28.67	28.48	28.03	27.99	28.88	29.62	30.11	30.43
East North Central	27.40	27.71	28.09	28.27	28.22	28.15	27.97	28.59	29.61	30.25	30.20	29.73
West North Central	27.30	27.61	27.99	28.16	28.12	28.05	27.87	28.49	29.50	30.14	30.09	29.62
South Atlantic	28.68	29.00	28.87	28.48	27.61	27.25	27.28	27.55	28.56	29.33	29.86	30.18
East South Central	27.98	28.29	28.16	27.78	26.93	26.58	26.61	26.87	27.86	28.61	29.13	29.43
West South Central	26.92	27.22	27.09	26.73	25.91	25.58	25.60	25.86	26.81	27.52	28.03	28.32
Mountain	25.61	26.05	27.21	27.69	27.64	27.54	27.11	27.16	28.08	28.54	28.52	27.87
Pacific	27.78	28.25	29.51	30.03	29.98	29.87	29.41	29.46	30.46	30.95	30.93	30.22
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 8C.3.47 Residential Monthly Oil Prices for 2013 Using Average Price Factors (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	28.13	28.54	28.34	28.10	27.93	27.74	27.30	27.26	28.13	28.85	29.33	29.64
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	27.42	27.73	28.11	28.29	28.25	28.18	28.00	28.61	29.63	30.27	30.23	29.75
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	27.46	27.78	28.16	28.34	28.29	28.22	28.04	28.66	29.68	30.32	30.28	29.80
Kansas, Nebraska	27.39	27.70	28.08	28.26	28.21	28.14	27.96	28.58	29.60	30.24	30.19	29.72
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	29.16	29.48	29.35	28.96	28.07	27.71	27.73	28.01	29.04	29.81	30.36	30.68
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	28.59	28.91	28.78	28.39	27.52	27.17	27.19	27.46	28.47	29.23	29.77	30.08
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	27.37	27.67	27.55	27.18	26.35	26.01	26.03	26.29	27.26	27.99	28.50	28.80
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	27.12	27.42	27.30	26.93	26.11	25.77	25.80	26.05	27.01	27.73	28.24	28.54
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	24.26	24.68	25.78	26.23	26.19	26.09	25.69	25.73	26.61	27.04	27.02	26.40
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	26.54	26.99	28.19	28.69	28.64	28.53	28.09	28.14	29.10	29.57	29.55	28.87
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	27.15	27.62	28.84	29.35	29.30	29.19	28.74	28.79	29.77	30.25	30.23	29.54
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

8C.4 SAMPLE ENERGY PRICE ADJUSTMENT FACTOR

DOE determined an energy price adjustment factors that account for the fact that building energy prices vary inside a geographical area. First, DOE developed average energy prices for each geographical region based on the total annual consumption and expenditure of each energy

use type reported by CBECS 2003 or RECS 2009. The adjustment factors are equal to the reported national average energy price in CBECS 2003 and RECS 2009 divided by the average energy price of the geographical region. These factors are then multiplied by the monthly marginal and average energy prices developed above to determine the building energy price.

8C.5 ENERGY PRICE TRENDS

8C.5.1 Commercial Energy Price Trends

DOE used EIA's 2015 Annual Energy Outlook (*AEO 2015)* Reference Case scenarios for the nine census divisions.[5] 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.

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*. DOE converted the forecasted energy prices into energy price factors, with 2013 as the base year. Figure 8C.5.1 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.

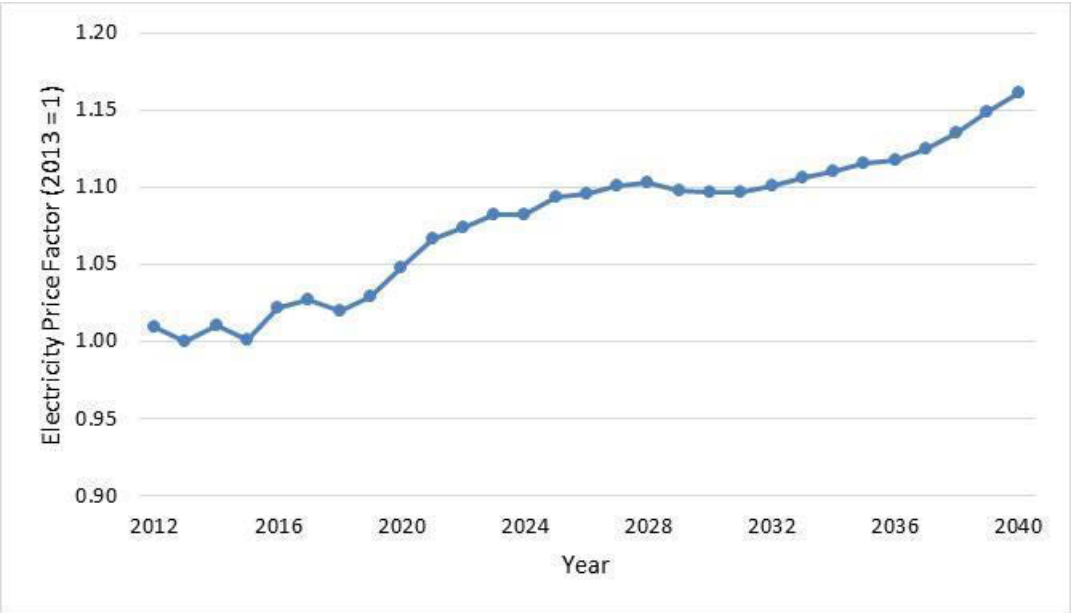

Figure 8C.5.1 Projected Commercial National Electricity Price Factors

Figure 8C.5.2 shows the commercial national electricity price factor trends disaggregated by the nine census divisions.

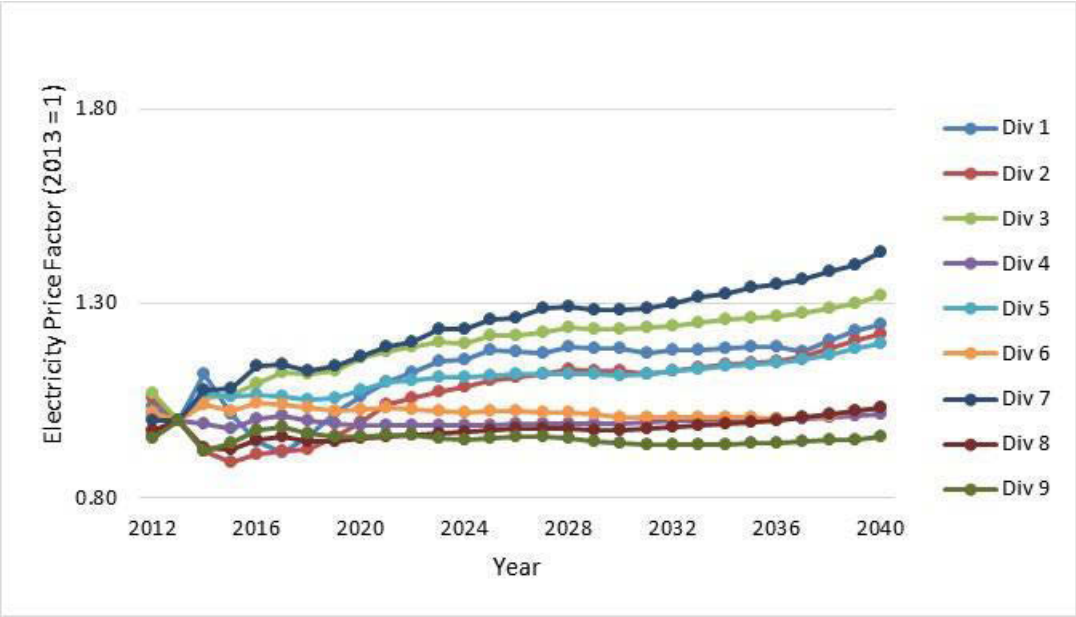

Figure 8C.5.2 Projected Commercial Electricity Price Factors by Census Division

Figure 8C.5.3 shows the commercial national natural gas price factor trend.

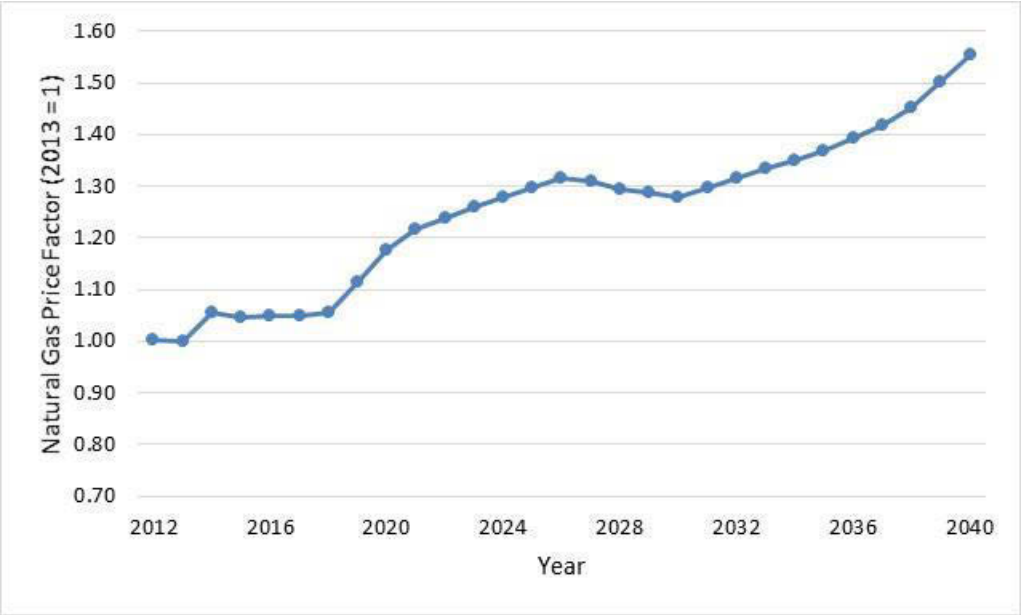

Figure 8C.5.3 Projected Commercial National Natural Gas Price Factors

Figure 8C.5.4 shows the commercial national natural gas price factor trends disaggregated by the nine census divisions.

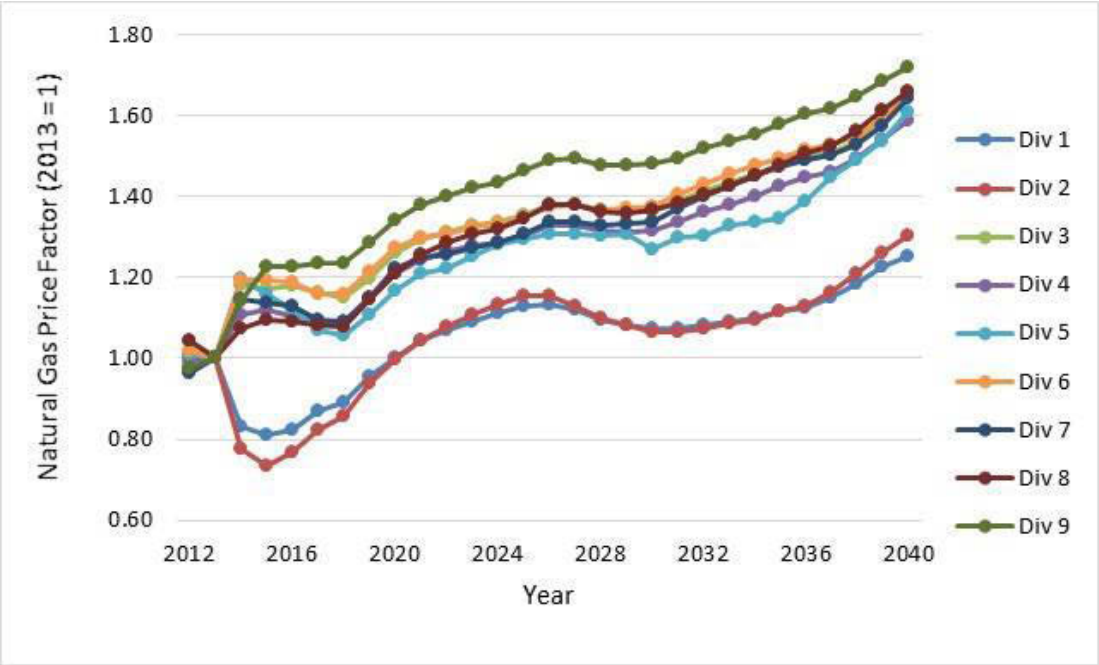

Figure 8C.5.4 Projected Commercial Natural Gas Price Factors by Census Division

Figure 8C.5.5 shows the commercial national LPG price factor trend.

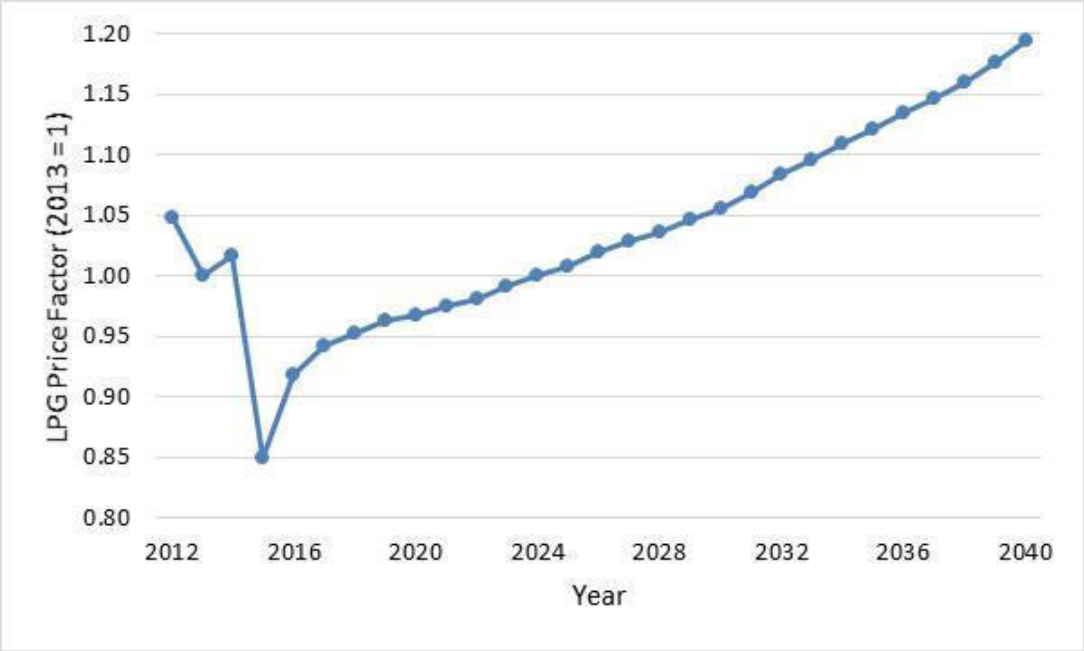

Figure 8C.5.5 Projected Commercial National LPG Price Factors

Figure 8C.5.6 shows the commercial national LPG price factor trends disaggregated by the nine census divisions.

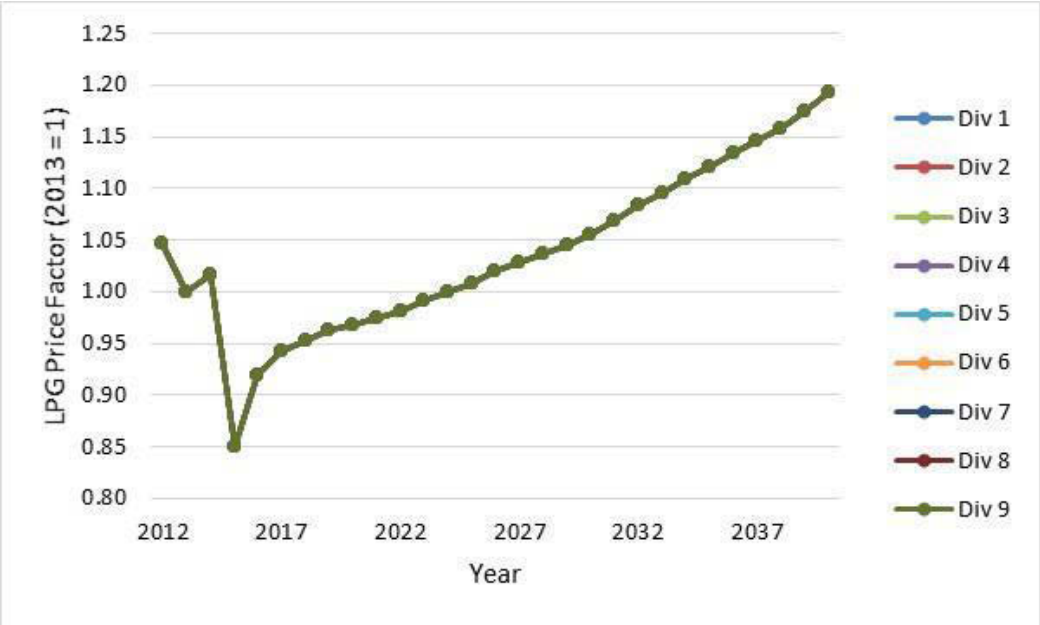

Figure 8C.5.6 Projected Commercial LPG Price Factors by Census Division

Figure 8C.5.7 shows the commercial national fuel oil price factor trend.

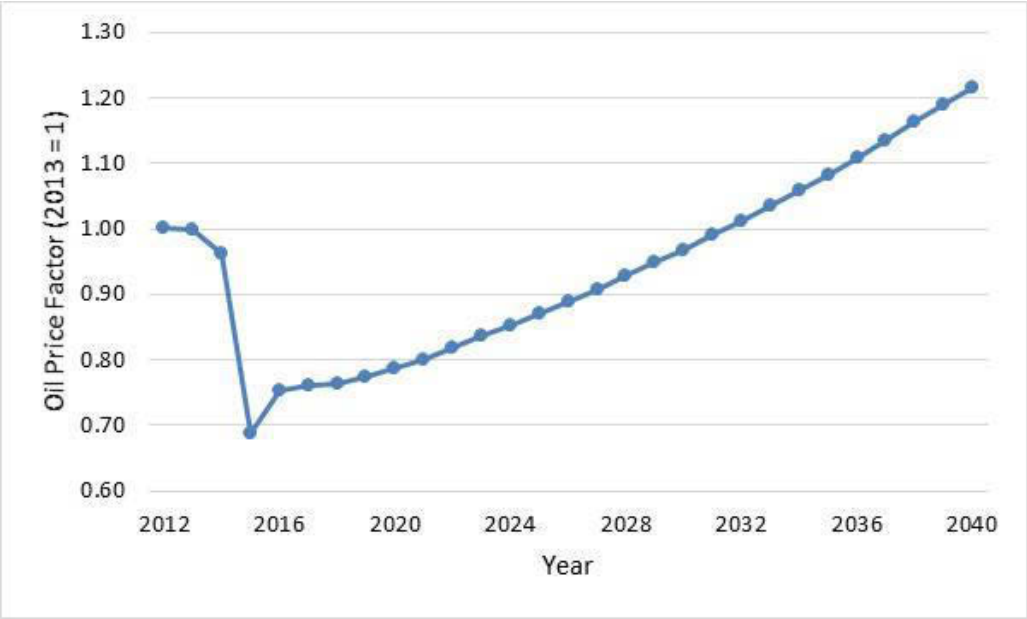

Figure 8C.5.7 Projected Commercial National Fuel Oil Price Factors

Figure 8C.5.8 shows the commercial national fuel oil price factor trends disaggregated by the nine census divisions.

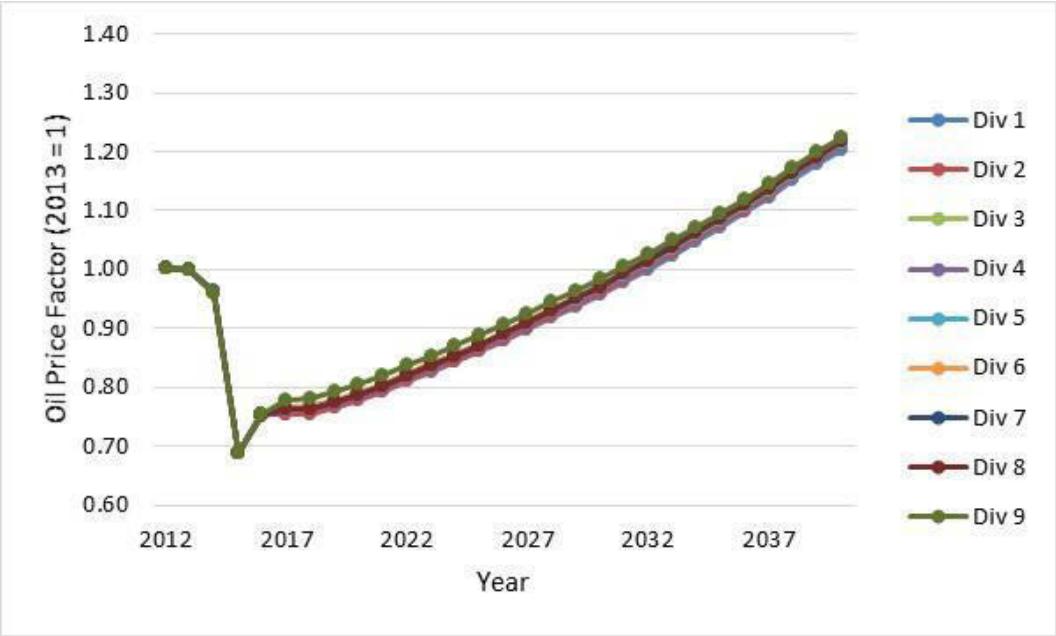

Figure 8C.5.8 Projected Commercial Fuel Oil Price Factors by Census Division

8C.5.2 Residential 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 residential 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 *AEO 2015.* DOE converted the forecasted energy prices into energy price factors, with 2013 as the base year. Figure 8C.5.9 shows the national residential electricity price 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 2025–2040 for electricity, natural gas, LPG, and fuel oil.

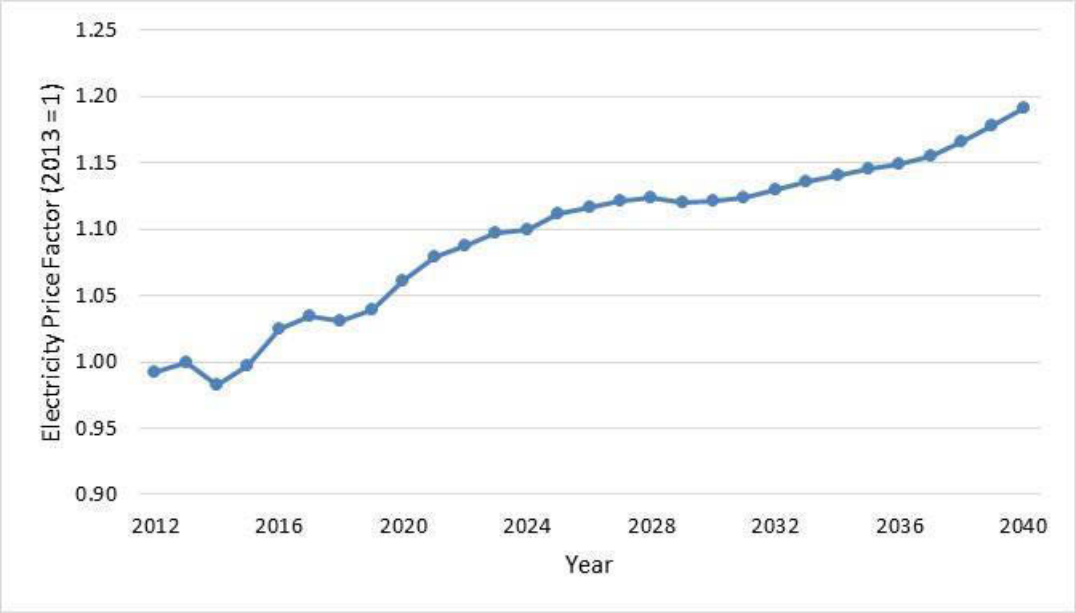

Figure 8C.5.9 Projected Residential National Electricity Price Factors

Figure 8C.5.10 shows the residential national electricity price factor trends disaggregated by the nine census divisions.

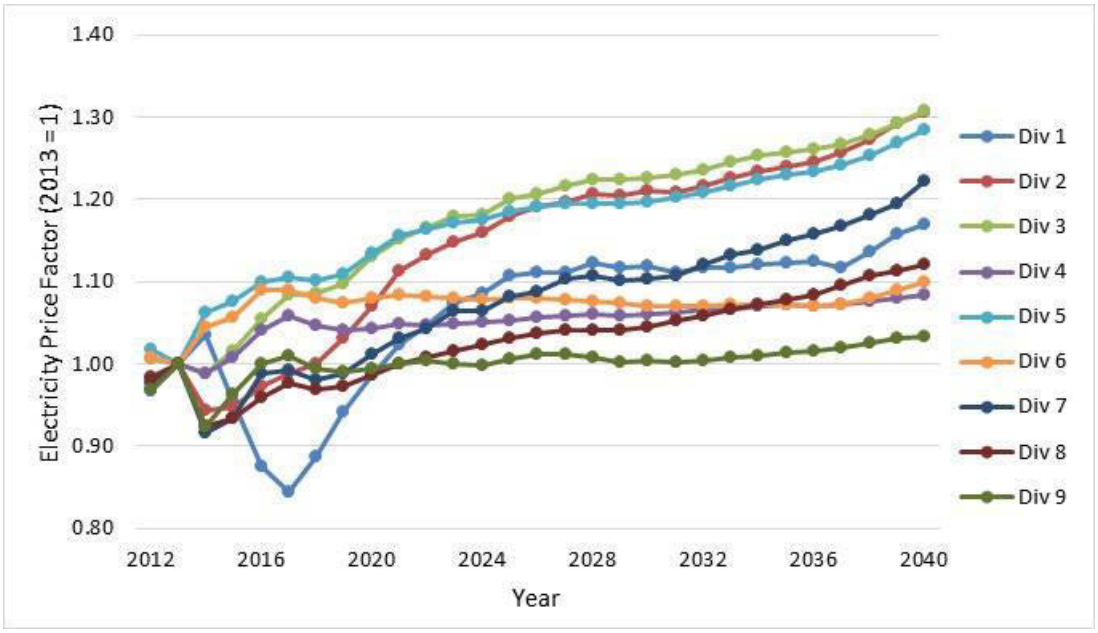

Figure 8C.5.10 Projected Residential Electricity Price Factors by Census Division

Figure 8C.5.11 shows the residential national natural gas price factor trend.

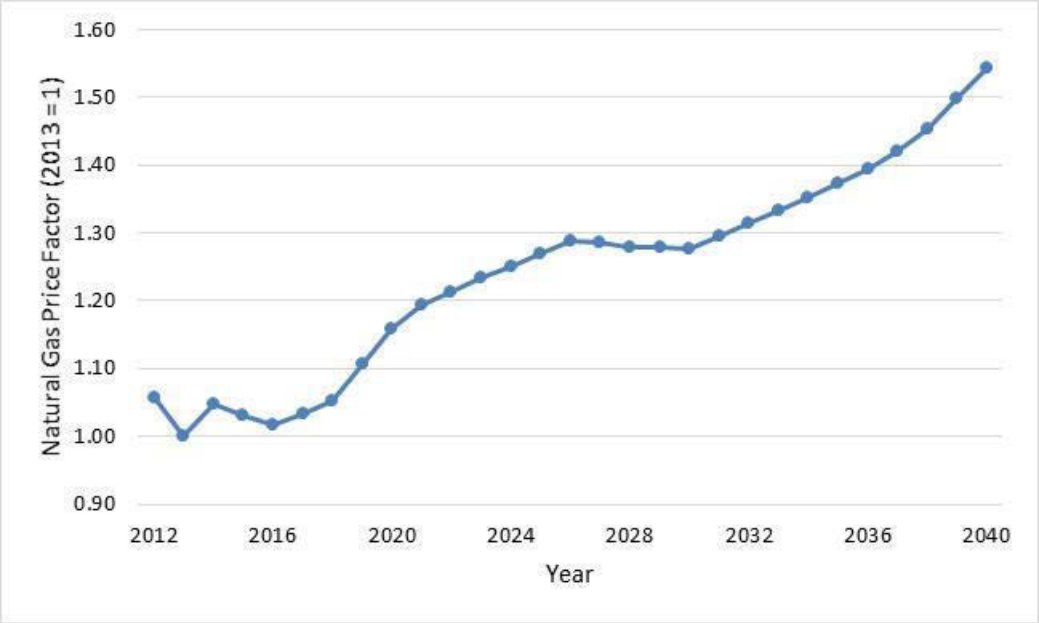

Figure 8C.5.11 Projected Residential National Natural Gas Price

Figure 8C.5.12 shows the residential national natural gas price factor trends, disaggregated by the nine census divisions.

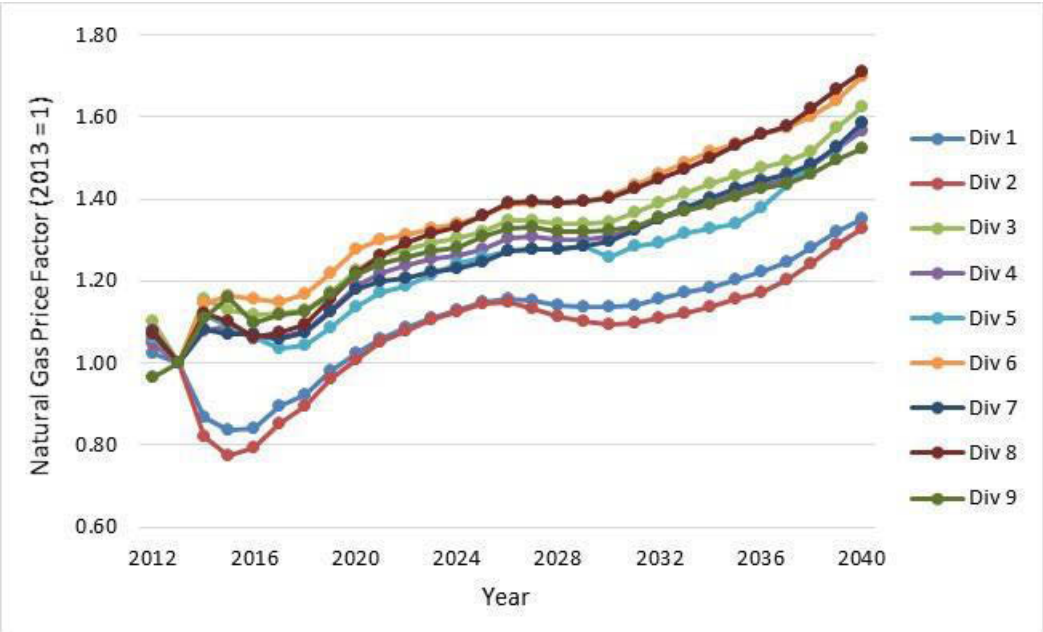

Figure 8C.5.12 Projected Residential Natural Gas Price Factors by Census Division

Figure 8C.5.13 shows the residential national LPG price factor trend.

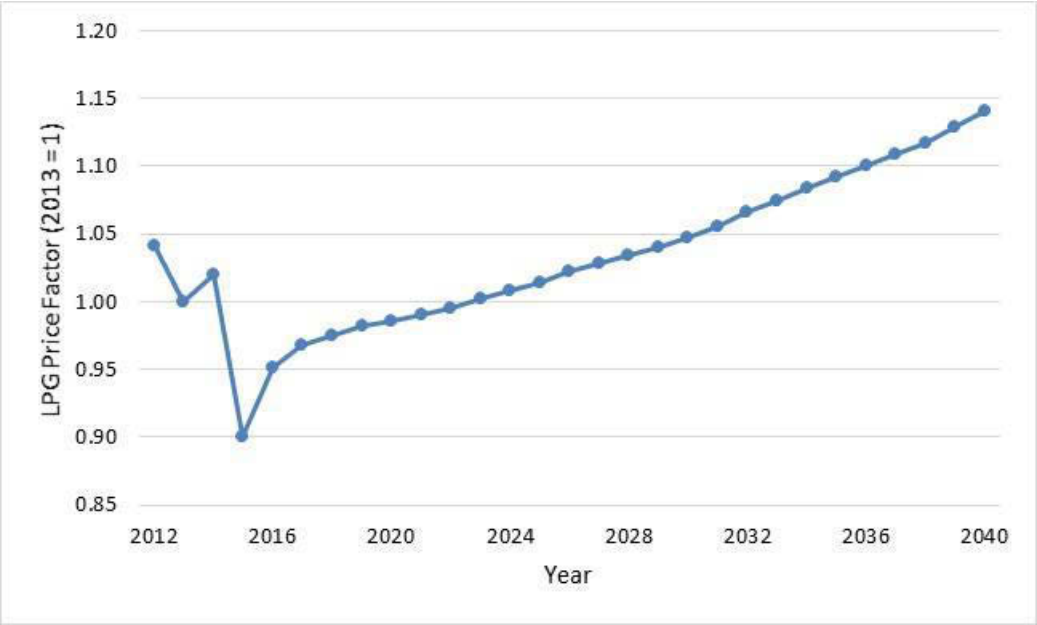

Figure 8C.5.13 Projected Residential National LPG Price Factors

Figure 8C.5.14 shows the residential national LPG price factor trends disaggregated by the nine census divisions.

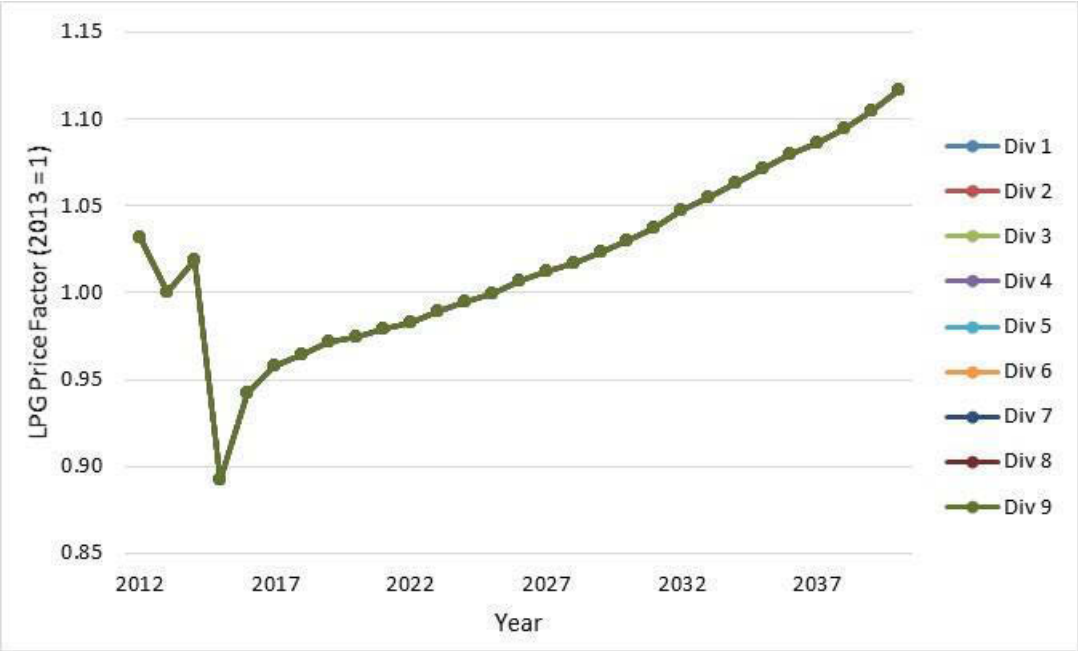

Figure 8C.5.14 Projected Residential LPG Price Factors by Census Division

Figure 8C.5.15 shows the residential national fuel oil price factor trend.

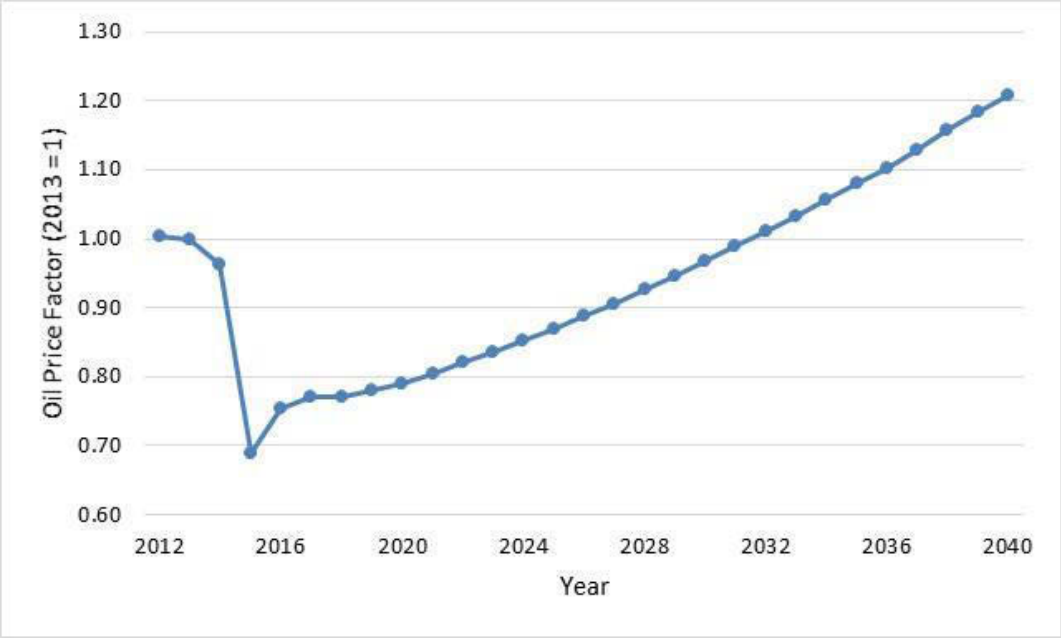

Figure 8C.5.15 Projected Residential National Fuel Oil Price Factors

Figure 8C.5.16 shows the residential national fuel oil price factor trends disaggregated by the nine census divisions.

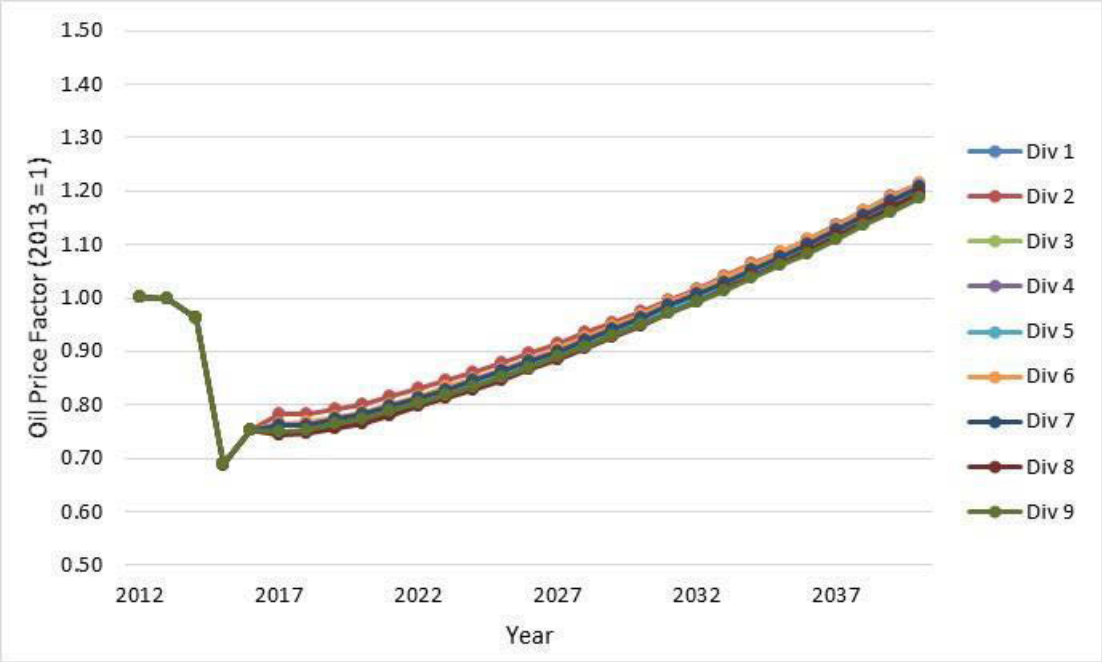

Figure 8C.5.16 Projected Residential Fuel Oil Price Factors by Census Division

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APPENDIX 8D. INSTALLATION COST DETERMINATION FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

8D.1 INTRODUCTION 8D-1
8D.2 INSTALLATION COST METHODOLOGY 8D-2
8D.2.1 Introduction 8D-2
8D.2.2 Installation Cost Inputs 8D-2
8D.2.3 Condensate Removal for Condensing Commercial Warm Air Furnaces 8D-3
8D.2.4 Venting for Indoor Installations Only 8D-4
8D.2.4.1 Vent Pipe Length 8D-5
8D.2.4.2 Replacement Installations 8D-6
8D.2.4.1 New Construction and New Owner Installations 8D-8
8D.3 RS MEANS 2013 REGIONAL LABOR COSTS 8D-8

LIST OF TABLES

Table 8D.1.1 Example Installation Cost Table 8D-1
Table 8D.2.1 Installation Criteria for Condensate Removal 8D-4
Table 8D.3.1 RS Means 2013 National Average Labor Costs by Crew (Commercial, Standard Union) 8D-9
Table 8D.3.2 Material and Labor Cost Factors by CBECS 2003 Geographical Area 8D-9

LIST OF FIGURES

Figure 8D.2.1 Average Wall to Horizontal Vent Length Ratio (Replacements) 8D-6

APPENDIX 8D. INSTALLATION COST DETERMINATION FOR COMMERCIAL WARM AIR FURNACES

8D.1 INTRODUCTION

This appendix provides further details about the derivation of installation costs for commercial warm air furnaces (CWAF). The installation cost is the price to the consumer of labor and materials (other than the cost of the actual equipment) needed to install CWAF equipment.

The Department of Energy (DOE) estimated installation costs for CWAF based on RS Means, a well-known and respected construction cost estimation method, as well as manufacturer literature and information from expert consultants. Table 8D.1.1 offers an example of the installation cost calculation. All labor costs are derived using the commercial 2013 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 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 labor costs to more accurately estimate installation costs by region. Section 8D.3 describes the derivation of regional labor costs. DOE then applied the appropriate regional labor cost to each CBECS or RECS sample building. The total costs include O&P. (Note that the unit "L.F." in the tables means "linear foot.")

Table 8D.1.1 Example Installation Cost Table

Description	Crew	Labor Hours	Unit	Bare Costs *(2009$)*			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 CWAF encompass a broad array of equipment classes, installation sizes, and venting configurations, including:

- gas-fired CWAF and oil-fired CWAF;
- new construction and replacement markets;
- commercial and multi-family buildings;
- condensate removal for condensing designs
- for indoor CWAF that require venting: various vent types, such as masonry chimneys,

metal vent, or plastic (polyvinylchloride (PVC)); venting systems that are Category I (non-condensing) and Category IV (condensing); single-wall or double-wall vent connectors; and special situations, such as the need to reline a chimney.

Applying the RS Means methodology to a CWAF installation requires knowledge of its details about the condensate withdrawal requirements and for indoor units requiring venting these details include the vent length, venting material, vent type, diameter, and number of elbow. To estimate these quantities, DOE reviewed relevant literature, data, and installation manuals. Each estimate was a distribution of values derived from available data; a Crystal Ball Monte Carlo simulation[a] was used to model the resultant costs for each individual building type.

8D.2 INSTALLATION COST METHODOLOGY

8D.2.1 Introduction

DOE developed installation cost data for CWAF using RS Means cost data, DOE technical support documents, and consultant interactions for this analysis.[1,2] The installation cost was divided into the following three components:

- basic installation,
- condensate removal, and
- venting for indoor equipment.

The following information about market shares, technologies, and installation location helped to shape the installation cost calculations.

8D.2.2 Installation Cost Inputs

The following information about market shares, technologies, and installation location helped to shape the installation cost calculations.

New Construction and Replacement Market Shares. As determined in the shipment analysis portion of the national impact analysis (NIA) (see chapter 9), for gas-fired CWAF, approximately 20 percent of the market will be new construction and 80 percent will be replacements in 2019. For oil-fired CWAF, approximately 5 percent of the market will be new construction and 95 percent will be replacements in 2019.

Commercial and Residential Market Shares. As determined in the shipment analysis (see chapter 9), for gas-fired CWAF, approximately 98 percent of the market will be commercial and 2 percent will be residential in 2019.

Commercial Warm Air Furnace Technologies. There are two main CWAF designs: non-condensing and condensing. Almost all of the non-condensing CWAF have a thermal

[a] See chapter 8 for a description of the Monte Carlo simulation methodology.

efficiency (TE) between 80 and 82 percent. Condensing CWAF have a TE of 90 percent or greater. Non-condensing CWAF installed indoors usually use Category I venting systems, while condensing CWAF installed indoors 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 IV venting system uses positive pressure and a plastic (PVC) vent.

Installation Locations. Ninety-five percent of gas-fired CWAF are installed outdoors packaged with a CUAC, while 100 percent of oil-fired CWAF are installed indoors. For CWAF installed indoors in commercial buildings, DOE assumed that 40 percent of the time they would be installed in a basement, 20 percent in an indoor location, and 40 percent in an equipment room.

Basic Installation Costs. For CWAF, DOE estimated basic installation costs that are applicable to both replacement and new building installations. These costs, which apply to both condensing and non-condensing CWAF, include putting in place and setting up the CWAF, gas or oil piping, ductwork hookup, electrical hookup for the thermostat, and permit and removal or disposal fees for replacement installations.

8D.2.3 Condensate Removal for Condensing Commercial Warm Air Furnaces

Condensate removal is required for all condensing CWAF installations in both replacement and new construction cases. DOE considered the following when assessing the cost of condensate removal:

- *Condensate Pipe:* For condensing CWAF, 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 Freeze Protection:* If the condensate is exposed to freezing temperatures, then heat tape and pipe insulation is required. DOE assumes that heat protection is required in all outdoor installations that experience below-freezing temperatures.
- *Condensate Neutralizer:* Some codes require a condensate neutralizer. DOE assumed 12.5 percent of installations would require it.
- *Additional Electrical Outlet:* DOE assumed that half of installations requiring a condensate pump or heat tape would also require an additional electricity outlet. DOE included this additional cost.

Table 8D.2.1 summarizes the condensate removal criteria associated with condensing CWAF.

Table 8D.2.1 Installation Criteria for Condensate Removal

Installation Cost Description	Criteria
Pipe	All installations
Pump	Indoor installations without AC
Freeze Protection (Heat Tape and Insulation)	All outdoor installations with an outdoor design temperature ≤ 32°F
Additional Electrical Outlet	50% of installations requiring a condensate pump or heat tape
Condensate Neutralizer	12.5% of all installations

*All oil-fired CWAF are assumed to be installed indoors, and thus do not require freeze protection.

In addition to the installation costs, the electricity use of the pump and heat tape is taken into account (42 watts for heat tape and 60 watts for the condensate pump) in the energy use calculations (see chapter 7). In addition, the cost of checking the condensate system and replacing the condensate neutralizer is taken into account in the maintenance costs (see appendix 8E).

DOE did not consider condensate disposal costs for non-condensing CWAF because even if these models may produce condensate under certain conditions, they generally do not produce enough condensate to require withdrawal from the unit. For a fraction of outdoor installations for which protection against condensate production may be needed, DOE assumed that CWAF that use various grades of stainless steel heat exchangers will be available and used by installers (see chapter 5).

8D.2.4 Venting for Indoor Installations Only

DOE estimated the venting installation costs for the small fraction of indoor CWAF installations. Estimating venting costs is complex because there are a large variety of possible installation scenarios. DOE calculated venting costs for each building in the CBECS 2003 or RECS 2009 CWAF 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), vents (metal or plastic), vent connectors, and chimney type.

Non-condensing CWAF 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 it does condense and does not re-evaporate quickly during the firing cycle, it could corrode the vent, the heat exchanger, or both, thus reducing the lifetime of the vent system or the CWAF itself. Typically, a small amount of condensate at cold startup is acceptable as long as it dries out quickly. Some non-condensing CWAF are vented using metal vents, either single wall or Type B double wall. For this analysis, DOE assumed that almost all existing and all new metal vents are Type B double wall.

More efficient low-temperature condensing CWAF condense the water vapor in the primary or a secondary heat exchanger, thus increasing energy efficiency by reducing latent heat loss. The condensate is fed to a drain. Because the flue gas temperature is relatively low, condensing CWAF can be vented through PVC piping. DOE assumed that all condensing CWAF are vented using PVC vents, either horizontal or vertical. One vent exhausts the flue gases and the other brings combustion air from the outside to the furnace. Flue gas piping is sloped downward toward the CWAF so that condensate drips back into the condensate drain.

8D.2.4.1 Vent Pipe Length

Figure 8D.2.1 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.

Vent pipe length is determined by taking into account:

- CWAF location in the building,
- ceiling height,
- number of floors above the CWAF, and
- square footage of CWAF installation location.

DOE assumed that all non-condensing CWAF vent types (*i.e.*, metal vents) are vented vertically. DOE assumed that the shortest run between horizontal and vertical venting determined the vent length and orientation of condensing CWAF PVC venting.

To determine the vertical pipe length, DOE used data from CBECS 2003 or RECS 2009 on the number of floors, installation location, and floor height. These data were used to determine the number of floors above the CWAF and the resulting distance from the CWAF 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.

To determine the horizontal pipe length, DOE used the square footage of the building reported in CBECS 2003 or RECS 2009 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 8D.2.1). 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 CWAF is in a basement, equipment room, or other indoor location. The vertical vent height is assumed to be high enough to be above the snow level in the winter months.

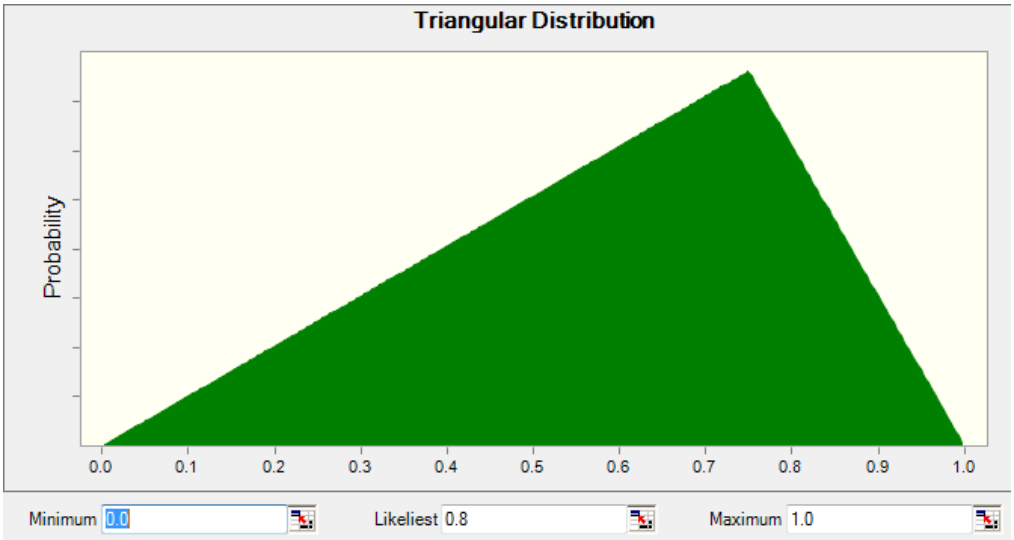

Figure 8D.2.1 Average Wall to Horizontal Vent Length Ratio (Replacements)

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.

8D.2.4.2 Replacement Installations

For replacements, DOE evaluated non-condensing to non-condensing CWAF replacements and non-condensing to condensing CWAF replacements.

Non-Condensing to Non-Condensing Commercial Warm Air Furnace Replacement Installations

Some non-condensing to non-condensing CWAF replacement installations require venting modifications to meet current safety requirements. There are two main issues that can arise when replacing a non-condensing CWAF with a more efficient non-condensing CWAF: 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; therefore, 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, making flue gases less likely to condense. Because of these different insulating properties, the National Fuel Gas Code (NFGC)[3] has different lining requirements for interior and exterior chimneys. These requirements are important because the cost of chimney relining is a major component of the installation cost of a CWAF. DOE's analysis assumed that all interior or exterior unlined chimneys will require relining upon replacement if built before 1995 or if the existing CWAF was installed before 1995.

DOE determined which CWAF installations in the entire CWAF sample would require chimney relining based on CBECS 2003 and RECS 2009 equipment age data and the fraction of

chimney installations. For each bin DOE assigned an equipment installation year using a uniform distribution with the ranges shown in the table. Finally, using the fraction of chimney installations, DOE determined if the household had a chimney installation.

To determine if a building had an unlined chimney, DOE used the following two criteria:

1) CWAF exhaust gases are vented through a chimney.
2) The existing CWAF was installed before 1995 when building codes requiring the relining of chimneys were not yet in place.

Vent Resizing

Vent resizing occurs when the existing vent diameter is too large for the new CWAF. Two solutions are possible: 1) vent connector resizing (most common) or 2) vent resizing (less common). There are three main types of vent connectors: Type B double wall, single-wall galvanized steel, and single-wall aluminum. A 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 vent connectors are similar to galvanized steel single-wall vents and are found in some regions. Condensing CWAF do not require vent connectors. DOE assumed that all new vent connectors are Type B double wall.

DOE assumed that vent resizing occurs only when a non-condensing fan-assisted CWAF (a TE of 80 percent or greater) replaces a natural draft non-condensing CWAF (a TE of less than 75 percent). Although fan-assisted CWAF have been the only installed non-condensing designs since the early 1990s, there is still a fraction of the stock that includes natural draft non-condensing CWAF. Based on the consultant interactions, DOE assumed that 75 percent of the venting systems with existing natural draft CWAF would need replacement of the vent connectors, while in an additional 10 percent of the installations the entire venting system would have to be resized.

Non-Condensing to Condensing Commercial Warm Air Furnace Replacement Installations

This section explains the changes to the venting systems that would be required when installing condensing CWAF indoors and provide information about the fractions of impacted installations. The sections below address the following three installation issues:

- condensing flue vent (PVC);
- combustion air vent; and
- concealing vents.

Condensing Flue Vent (PVC)

When replacing an existing non-condensing CWAF with a condensing CWAF, the existing metal vent is replaced with a plastic (PVC) flue vent. The installation cost of the condensing CWAF flue vent takes into account the following:

- vent length (CWAF distance from wall or roof, and whether to install a vertical vent (through the roof) or a horizontal vent (through the wall), see section 8D.2.4.1); and
- wall type, which determines the cost of penetrating the wall.

Combustion Air Vent (PVC)

A fraction of the condensing CWAF installations are direct-vent installations, which use combustion air supplied from the outdoor air. For each building in the CBECS 2003 and RECS 2009 sample, DOE considered the following factors when calculating the installation cost of the combustion air vent for condensing CWAF in the replacement market:

- combustion air vent length, which is the same as flue pipe length; and
- combustion air vent installation fraction, which depends on the installation location.

DOE assumed that about two-thirds of condensing CWAF shipments are to direct vent installations. The cost of installing a direct vent was assumed to be the same as that of installing a new PVC vent.

Concealing Vent Pipes

For a fraction of indoor installations, DOE added an installation cost to conceal the PVC vent pipes—putting in place structures to mask vents that pass through the occupied space. DOE assumed that half of the indoor condensing CWAF installations that are horizontally vented would require such modifications.

8D.2.4.1 New Construction and New Owner Installations

For CWAF installations in new construction, DOE accounted for the installation cost of a new venting system for both non-condensing CWAF and condensing CWAF. For non-condensing installations, as in the replacement case, vent length is determined by taking into account the CWAF installation location and the number of floors above the CWAF. For condensing installations, DOE accounted for the installation of the plastic PVC flue vent, as well as for the combustion air vent in direct-vent systems.

8D.3 RS MEANS 2013 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 8D.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.

Table 8D.3.1 RS Means 2013 National Average Labor Costs by Crew (Commercial, Standard Union)

Crew Type	Crew Description	Laborers per Crew	Cost per Labor-Hour (2014$)	
			Bare Costs	Incl. O&P
Q1	1 Plumber, 1 Plumber Apprentice	2	$43.34	$65.27
Q9	1 sheet metal worker, 1 sheet metal worker apprentice	2	$41.39	$63.11
Q10	2 sheet metal worker, 1 sheet metal worker apprentice	3	$45.65	$69.61

* Q&P includes markups for operation and profit.

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. DOE used the material and labor cost factors for cost associated with fire suppression, plumbing, and HVAC. Table 8D.3.2 shows 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 (*i.e.*, labor cost factor of 1.00).

Table 8D.3.2 Material and Labor Cost Factors by CBECS 2003 Geographical Area

Geographical Area (Census Division)	Material	Labor
New England	0.99	1.06
Middle Atlantic	0.99	1.39
East North Central	0.99	1.03
West North Central	0.99	0.89
South Atlantic	0.99	0.63
East South Central	1.00	0.65
West South Central	0.99	0.57
Mountain	1.00	0.78
Pacific	0.99	1.17

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APPENDIX 8E. MAINTENANCE AND REPAIR COST DETERMINATION FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

8E.1 INTRODUCTION 8E-1
8E.2 MAINTENANCE COST FOR COMMERCIAL WARM AIR FURNACES 8E-1
8E.2.1 Low Sulfur Fuel Oil 8E-2
8E.2.1.1 Sulfur Production 8E-2
8E.2.1.2 Currently Regulatory Requirements 8E-3
8E.2.1.3 Reduction of Sulfur Effects on CWAF Maintenance 8E-3
8E.2.1.4 Low Sulfur Energy Prices 8E-5
8E.3 REPAIR COST FOR FURNACES 8E-5
8E.4 REGIONAL MATERIAL AND LABOR COSTS 8E-6

LIST OF TABLES

Table 8E.1.1 Example Cost Table 8E-1
Table 8E.4.1 RS Means 2013 National Average Labor Costs by Crew 8E-6
Table 8E.4.2 Material and Labor Cost Factors by CBECS 2003 Geographical Area 8E-6

LIST OF FIGURES

Figure 8E.2.1 States with Low Sulfur Regulations 8E-3
Figure 8E.2.2 Boiler Deposits by Fuel Oil Type 8E-4

APPENDIX 8E. MAINTENANCE AND REPAIR COST DETERMINATION FOR COMMERCIAL WARM AIR FURNACES

8E.1 INTRODUCTION

This appendix provides further details about the derivation of maintenance and repair costs for commercial warm air furnaces (CWAF).

The Department of Energy (DOE) estimated maintenance and repair costs for CWAF 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 2013 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 labor costs to more accurately estimate installation costs by region. Section 8E.4 describes the derivation of regional labor costs. DOE then applied the appropriate regional 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 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**

8E.2 MAINTENANCE COST FOR COMMERCIAL WARM AIR FURNACES

The maintenance cost is the routine annual cost to the commercial consumer of maintaining equipment operation. It is the cost associated with general maintenance. DOE estimated maintenance costs at each considered efficiency level using a variety of sources, including *2013 RS Means Facility Repair and Maintenance Data*,[1] manufacturer literature, and information from expert consultants. DOE added additional maintenance requirements for condensing CWAF including additional inspection of condensate system and replacement of neutralizer filter. DOE accounts for regional differences in labor costs, as discussed in section 8E.4.

The frequency with which the maintenance occurs was derived CBECS 2003 and RECS 2009 data about how often CWAF owners perform maintenance. Survey respondents signified

whether they performed regular maintenance. DOE assumed that regularly maintained CWAFs are maintained every year, while CWAFs that are not regularly maintained are maintained every five years. For condensing CWAF, 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.

In addition, DOE investigated the effects of recent low sulfur fuel oil requirements on oil-fired CWAF maintenance (section 8E.2.1). Based on this information, DOE adjusted maintenance costs to take into account these changes. Around 25 percent of CWAF shipments are to states which currently have or will have low sulfur restrictions. Some studies suggest that low sulfur fuel oil can reduce maintenance costs. For this analysis, DOE assumed that:

1) Non-regulated areas: Purchase high sulfur oil with the normal maintenance frequency for non-condensing and condensing equipment. For this analysis, the frequency of maintenance remains the same, but condensing maintenance requires an additional 0.254 hours of labor.

2) Regulated areas: Purchase low sulfur oil with decreased maintenance costs for all equipment. For this analysis, the frequency of maintenance is halved.

3) Oil prices are assumed to be already adjusted in *AEO 2015* projections.

8E.2.1 Low Sulfur Fuel Oil

8E.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.[2] Approximately 99 percent of the burned sulfur turns into sulfur dioxide (SO_2), which, when emitted to the atmosphere, can irritate lungs, contribute to pulmonary disease, and create haze.[3]

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 CWAF's efficiency, and damages the equipment.[3]

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.[4]

8E.2.1.2 Currently 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 be applied to heating oil.[5] The following chart shows the individual states that have also mandated ULSD levels for heating oil.[6]

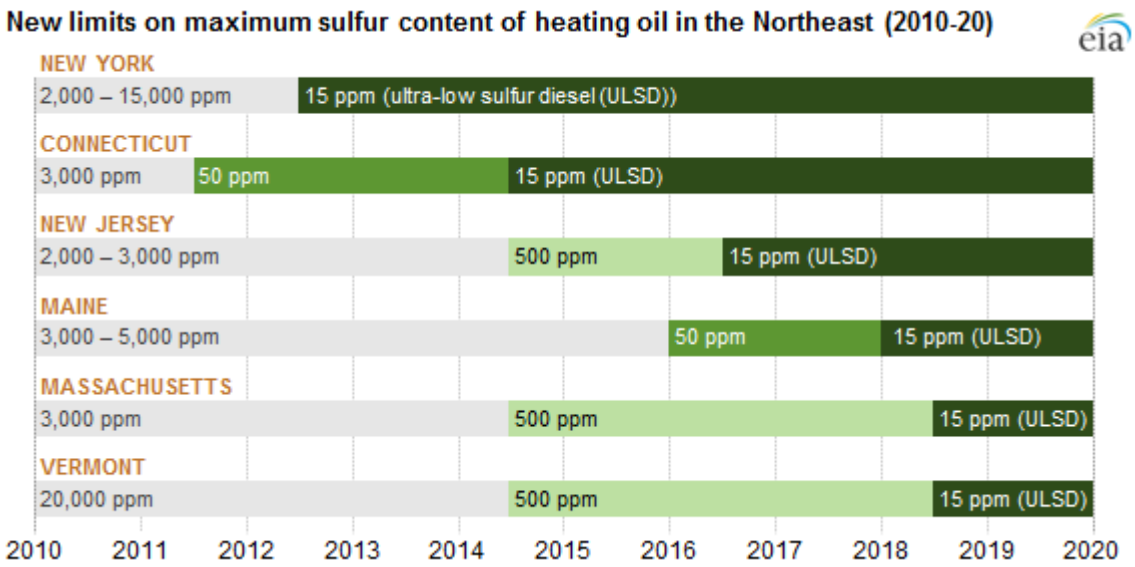

Figure 8E.2.1 States with Low Sulfur Regulations

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.[7–9]

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.[7] 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 the overall sulfur content.[10]

8E.2.1.3 Reduction of Sulfur Effects on CWAF Maintenance

A variety of sources cite the fact that lower-sulfur oil fuel can reduce operating and maintenance costs and improve furnace and boiler efficiency.[3,11,12] Because boiler and furnace heat exchangers are fairly similar, the findings presented in these sources were used to determine the impact of low sulfur oil fuel on CWAF maintenance. 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 exchangers.[3,13] 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.[10] 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:

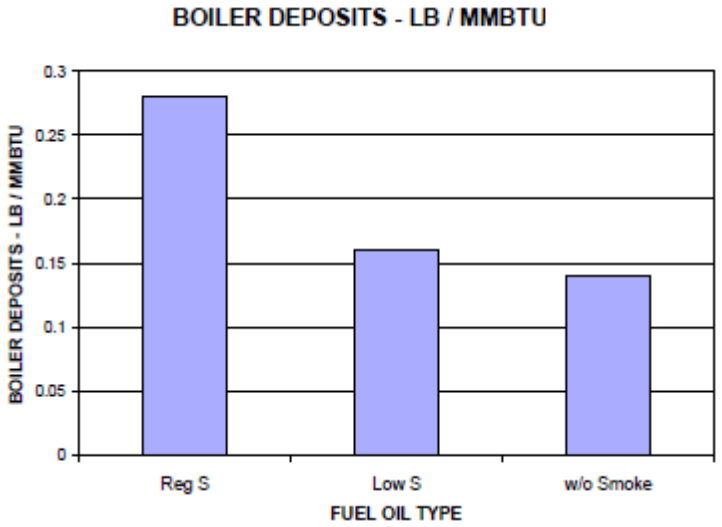

Figure 8E.2.2 Boiler Deposits by Fuel Oil Type

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 correspond with research conducted by Brookhaven National Laboratory and CAMET Energy Technology Centre in Canada.[13] 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.[10]

Using lower-sulfur heating oil with furnace or boiler systems can not only reduce the emission of particulate matter, but also allow the use of secondary condensing heat exchangers on oil-fired furnaces and boilers by greatly reducing or eliminating heat exchanger and venting system degradation from sulfuric acid produced as a byproduct of combustion.[14]

The are some downsides to low sulfur fuel: the German organization *Institut Fur wirtschafliche Oelheizung* performed research in 2003 by testing 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.[3] In addition, 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. In order 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.[15]

MJ Bradley and Associates recommend the following annual maintenance service for boilers that burn No. 2, distillate, heating oil:

- Burner tip and heat exchanger cleaning
- Ash and soot removal
- Flue gas analysis/carbon monoxide test
- Air intake filter replacement
- Oil filter replacement

8E.2.1.4 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.[10] Low sulfur regulations could also potentially affect the price of fuel oil. DOE found a 2003 report that cites the price differential between regular #2 heating oil and low sulfur oil as one to two cents per gallon.[10] 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.[4] 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."[6]

DOE believes that low sulfur oil pricing for regulated regions is already taken into account in EIA's *AEO 2015* projections.

8E.3 REPAIR COST FOR FURNACES

The repair cost is the cost to the commercial consumer for replacing or repairing components in the furnace that have failed. DOE estimated repair costs at each considered efficiency level using a variety of sources, including *2013 RS Means Facility Repair and Maintenance Data*, manufacturer literature, and information from expert consultants. DOE accounts for regional differences in labor costs, as discussed in section 8E.4.

DOE estimated that about 2 percent of CWAF are repaired annually based on Consumer Reports data on frequency of repair for residential gas furnaces installed between 2000 and 2006.[16] DOE assumes that this fraction is similar to commercial equipment. DOE assumed that an average repair has a parts cost equivalent to one-half of the equipment cost and requires 3 hours of labor. For this analysis, DOE annualized this cost for all CWAFs by multiplying the 2 percent to the average repair cost.

8E.4 REGIONAL MATERIAL AND 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 8E.4.1. 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.

Table 8E.4.1 RS Means 2013 National Average Labor Costs by Crew

Crew Type	Crew Description	Laborers per Crew	Cost per Labor-Hour (2014$)	
			Bare Costs	Incl. O&P*
Q1	1 Plumber, 1 Plumber Apprentice	2	$51.04	$79.42

* Q&P includes markups for operation and profit.

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. DOE used the material and labor cost factors for cost associated with fire suppression, plumbing, and HVAC. Table 8E.4.2 shows 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 (*i.e.*, labor cost factor of 1.00).

Table 8E.4.2 Material and Labor Cost Factors by CBECS 2003 Geographical Area

Geographical Area (Census Division)	Material	Labor
New England	0.99	1.06
Middle Atlantic	0.99	1.39
East North Central	0.99	1.03
West North Central	0.99	0.89
South Atlantic	0.99	0.63
East South Central	1.00	0.65
West South Central	0.99	0.57
Mountain	1.00	0.78
Pacific	0.99	1.17

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APPENDIX 8F. COMMERCIAL WARM AIR FURNACE LIFETIME DETERMINATION
TABLE OF CONTENTS

8F.1 INTRODUCTION 8F-1
8F.2 LIFETIME LITERATURE REVIEW 8F-1
8F.3 METHODOLOGY 8F-1

LIST OF TABLES

Table 8F.2.1 Commercial Warm Air Furnace: Equipment Lifetime Estimates and Sources 8F-1

LIST OF FIGURES

Figure 8F.3.1 Lifetime Distribution for All Commercial Warm Air Furnaces 8F-2

APPENDIX 8F. COMMERCIAL WARM AIR FURNACE LIFETIME DETERMINATION

8F.1 INTRODUCTION

DOE defines lifetime as the age when equipment is retired from service. For both gas-fired and oil-fired commercial warm air furnaces (CWAF), the lifetime probability distribution is based on commercial unitary air-conditioning (CUAC) equipment lifetime in the 2015 CUAC and commercial unitary heat pump (CUHP) direct final rule (DFR).[1] DOE estimated a median lifetime value of 22.1 years for all CWAF. DOE assumed that the lifetime is the same for all CWAF efficiency levels within each equipment class.

8F.2 LIFETIME LITERATURE REVIEW

DOE is aware that CWAF technology has evolved. To capture lifetime variances due to new CWAF technology, DOE performed a lifetime literature review. Table 8F.2.1 presents a range of equipment lifetimes and sources found by DOE. The data show that DOE's calculated lifetime for CWAF fits within the bounds of the current CWAF lifetime estimates.

Table 8F.2.1 Commercial Warm Air Furnace: Equipment Lifetime Estimates and Sources

Lifetime (years)	*Source*
Commercial Furnaces	
18*	Mid-Atlantic Technical Reference Manual (2011)[2]
18^	Krauss *et al.* (1992)[3]
18.5†	EIA (2013)[4]
17.5*	EIA (2013)[4]
Packaged Outdoor Units^	
15*	Cedar Hills Independent School District[5]
10	Pelle Heating & Air Conditioning, Inc.[6]
20	CDW Engineering (2013)[7]
Mean = 21.3, min = 14, max = 27	ASHRAE Service Life Database[8]
Light Commercial HVAC Equipment^	
15-20	Buildings Magazine (2003)[9]

*Gas
†Oil
^Unspecified fuel type

8F.3 METHODOLOGY

DOE defines lifetime as the age when equipment is retired from service. Because a "survival function" more accurately represents equipment lifetime than a single-point value, DOE created a survival function for CWAF based on the CUAC lifetime determined in the 2015

CUAC/CUHP DFR. DOE assumed that the lifetime of the CWAF equipment is the same at different efficiency levels and for both CWAF equipment classes.

DOE used the shipment-weighted average CUAC lifetime as the lifetime for CWAF because almost all CWAF are packaged with CUAC. Based on the CUAC shipments model, which was calibrated with historical shipments (see chapter 9), DOE determined lifetime for each CUAC equipment class. The CUAC lifetime by equipment class was then weighted by the shipments for each CUAC equipment class to determine the overall CWAF lifetime, which resulted in a median of 22.1 years and a mean of 23 years. The Weibull parameters are 24.81 (alpha) and 2.269 (beta). A plot of the Weibull distribution (DOE's calculated survival function) for all CWAF is shown in Figure 8F.3.1.

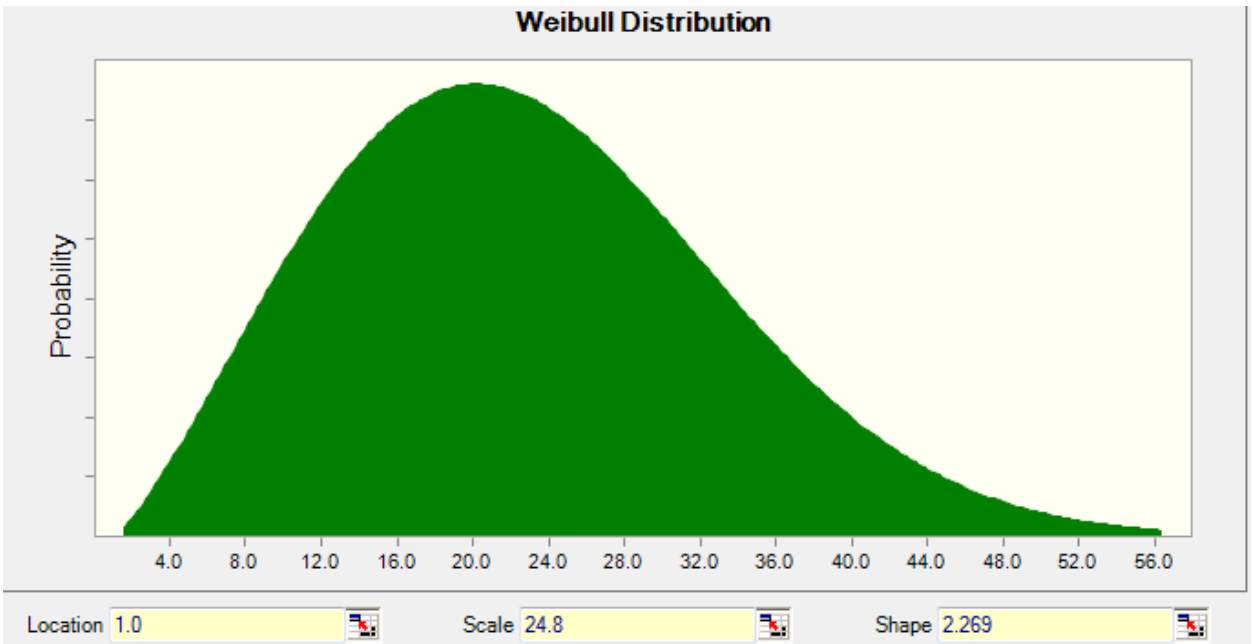

Figure 8F.3.1 Lifetime Distribution for All Commercial Warm Air Furnaces

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APPENDIX 8G. DISTRIBUTIONS USED FOR DISCOUNT RATES

TABLE OF CONTENTS

8G.1 INTRODUCTION 8G-1
8G.2 DISTRIBUTIONS USED FOR COMMERCIAL DISCOUNT RATES 8G-1
8G.3 DISTRIBUTIONS USED FOR CONSUMER DISCOUNT RATES 8G-6

LIST OF FIGURES

Figure 8G.2.1 Distribution of Commercial Discount Rates: Retail 8G-1
Figure 8G.2.2 Distribution of Commercial Discount Rates: Property 8G-2
Figure 8G.2.3 Distribution of Commercial Discount Rates: Medical 8G-2
Figure 8G.2.4 Distribution of Commercial Discount Rates: Industrial 8G-3
Figure 8G.2.5 Distribution of Commercial Discount Rates: Lodging 8G-3
Figure 8G.2.6 Distribution of Commercial Discount Rates: Food Service 8G-4
Figure 8G.2.7 Distribution of Commercial Discount Rates: Office 8G-4
Figure 8G.2.8 Distribution of Commercial Discount Rates: State and Local Government 8G-5
Figure 8G.2.9 Distribution of Commercial Discount Rates: Federal Government 8G-5
Figure 8G.2.10 Distribution of Commercial Discount Rates: Other 8G-6

APPENDIX 8G. DISTRIBUTIONS USED FOR DISCOUNT RATES

8G.1 INTRODUCTION

The Department of Energy (DOE) estimated discount rate distributions by application type: commercial and residential. This appendix describes the distributions used.

8G.2 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.[1] 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.[2] Separate distributions were constructed for each major industry. Figure 8G.2.1 through Figure 8G.2.9 show the probability distributions of commercial discount rates by industry.

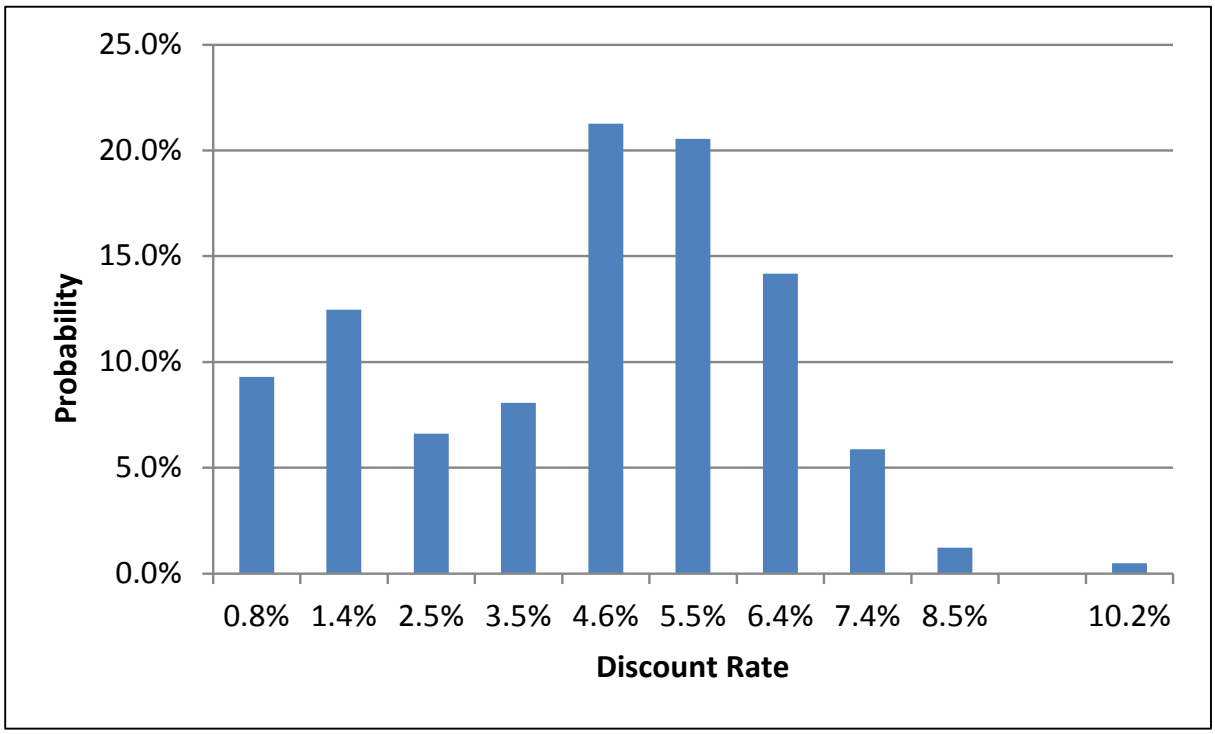

Figure 8G.2.1 Distribution of Commercial Discount Rates: Retail

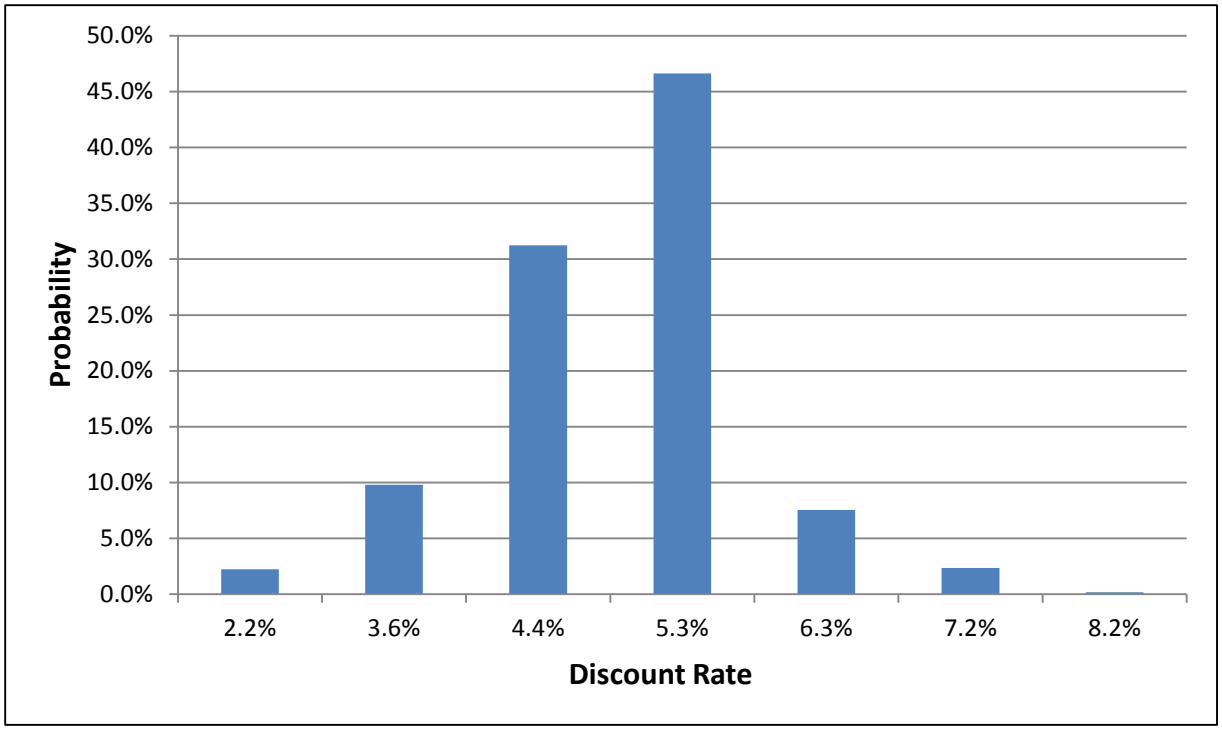

Figure 8G.2.2 Distribution of Commercial Discount Rates: Property

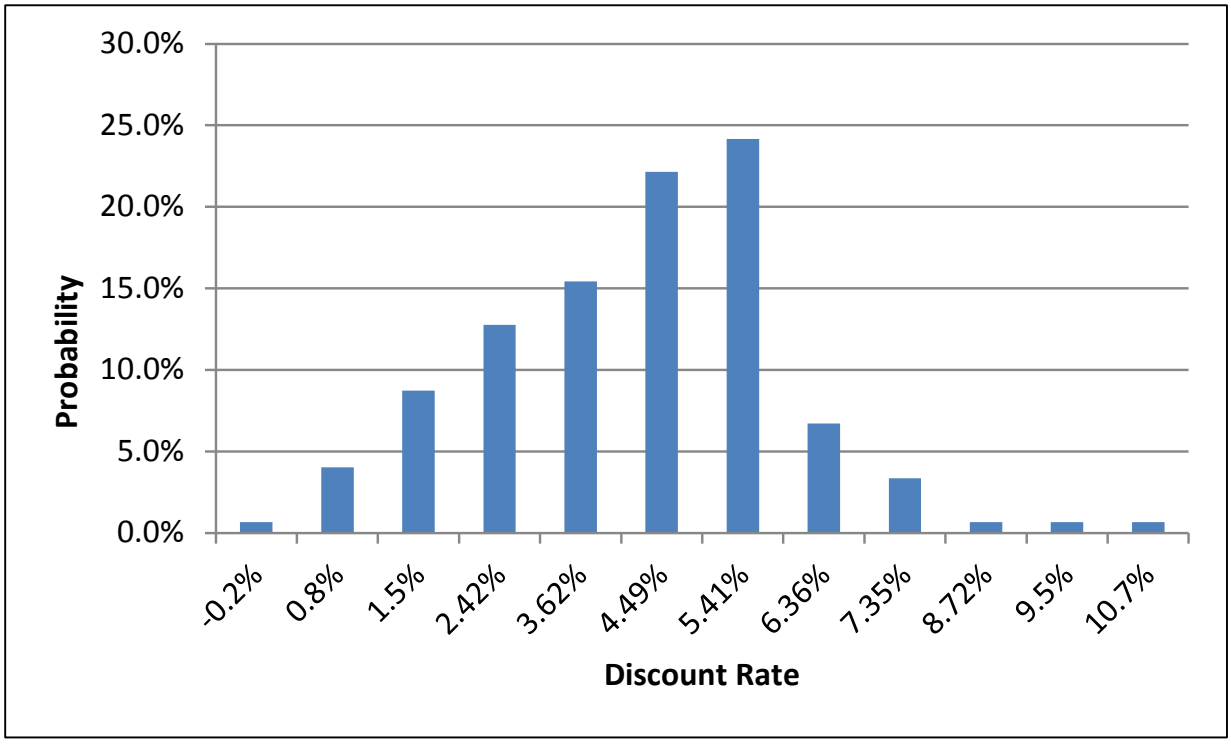

Figure 8G.2.3 Distribution of Commercial Discount Rates: Medical

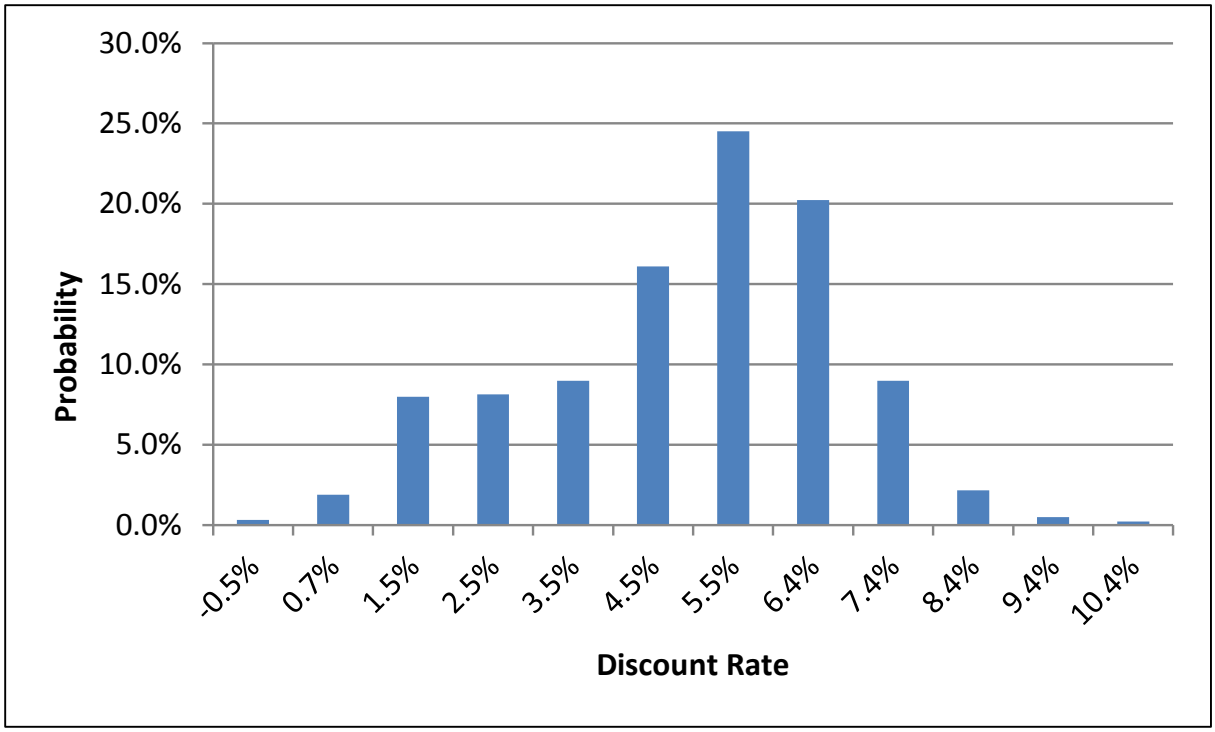

Figure 8G.2.4 Distribution of Commercial Discount Rates: Industrial

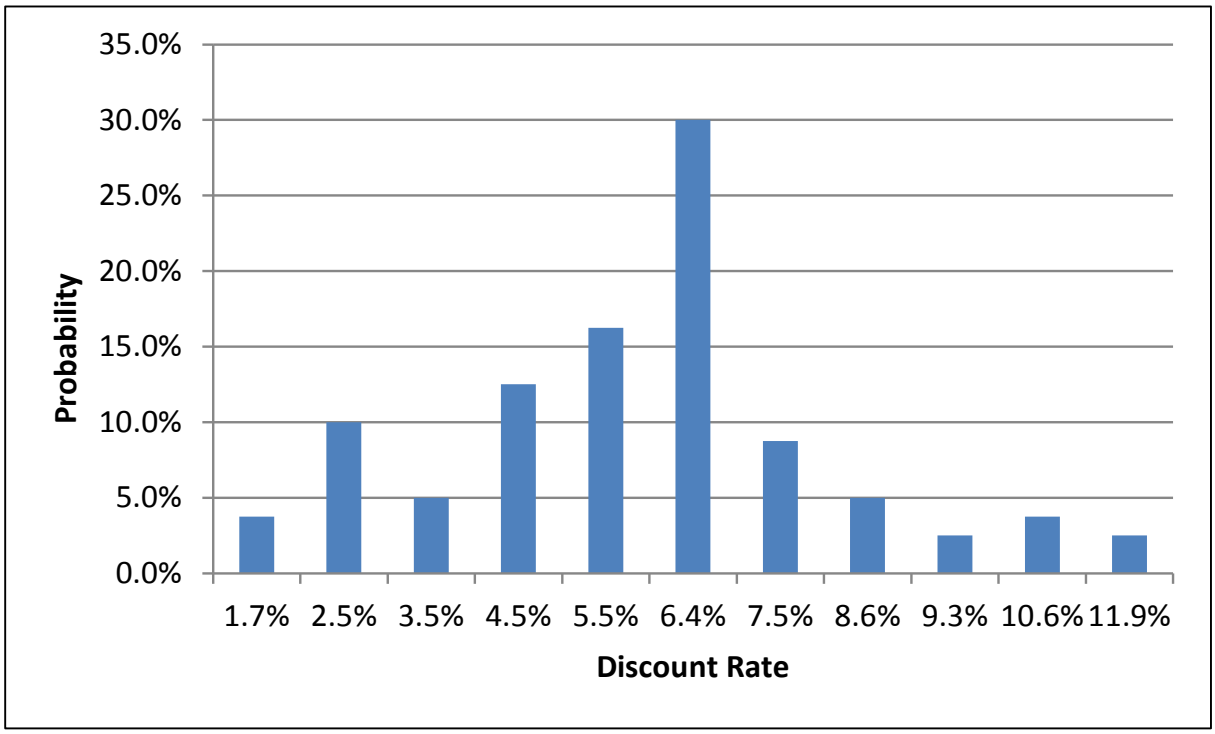

Figure 8G.2.5 Distribution of Commercial Discount Rates: Lodging

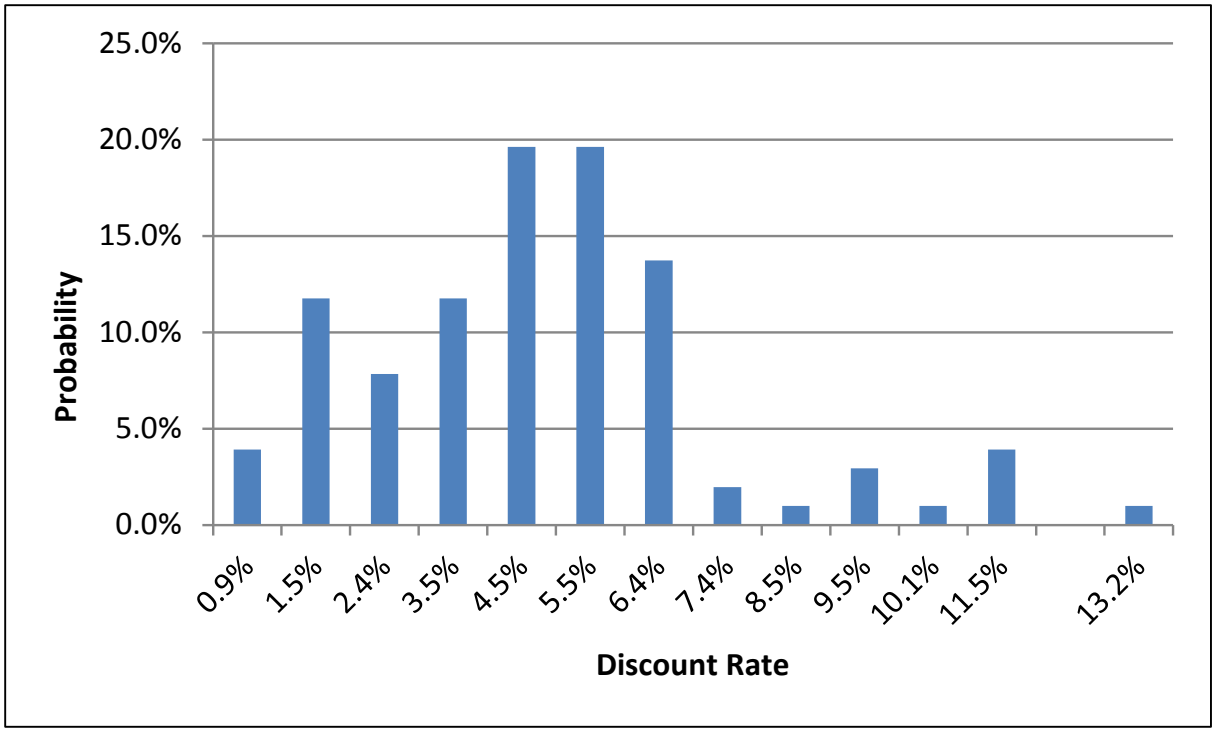

Figure 8G.2.6 Distribution of Commercial Discount Rates: Food Service

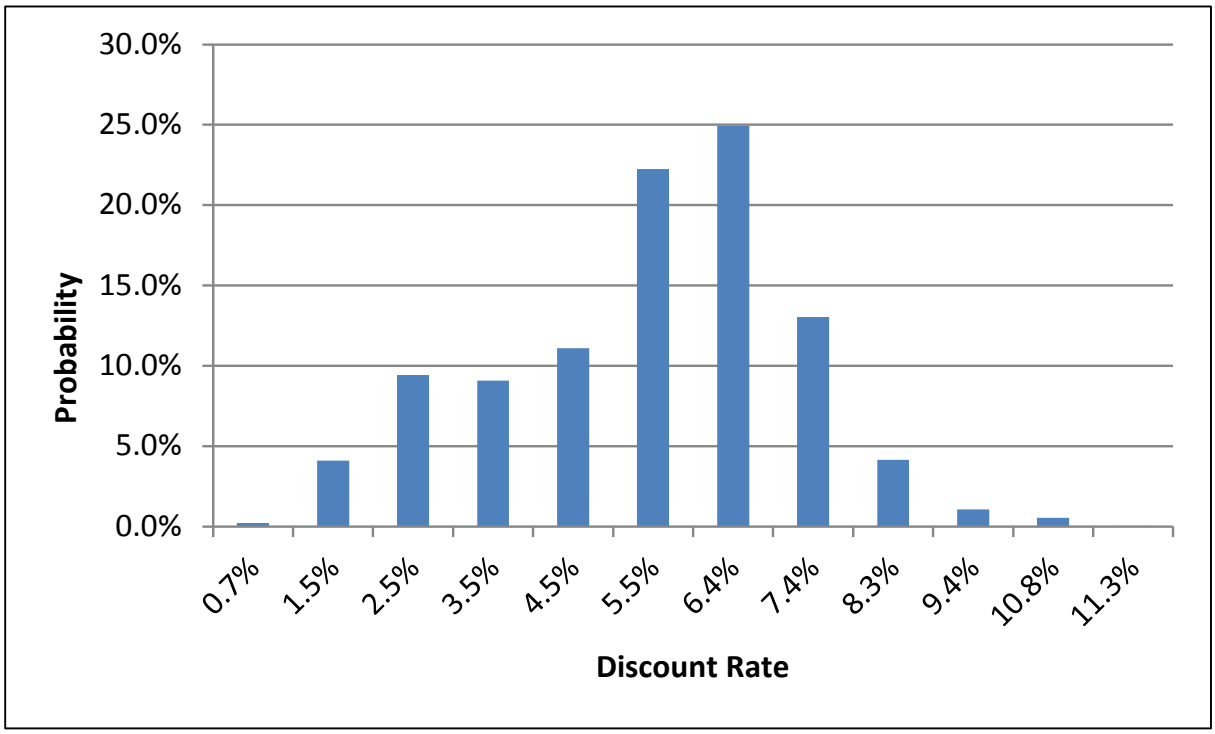

Figure 8G.2.7 Distribution of Commercial Discount Rates: Office

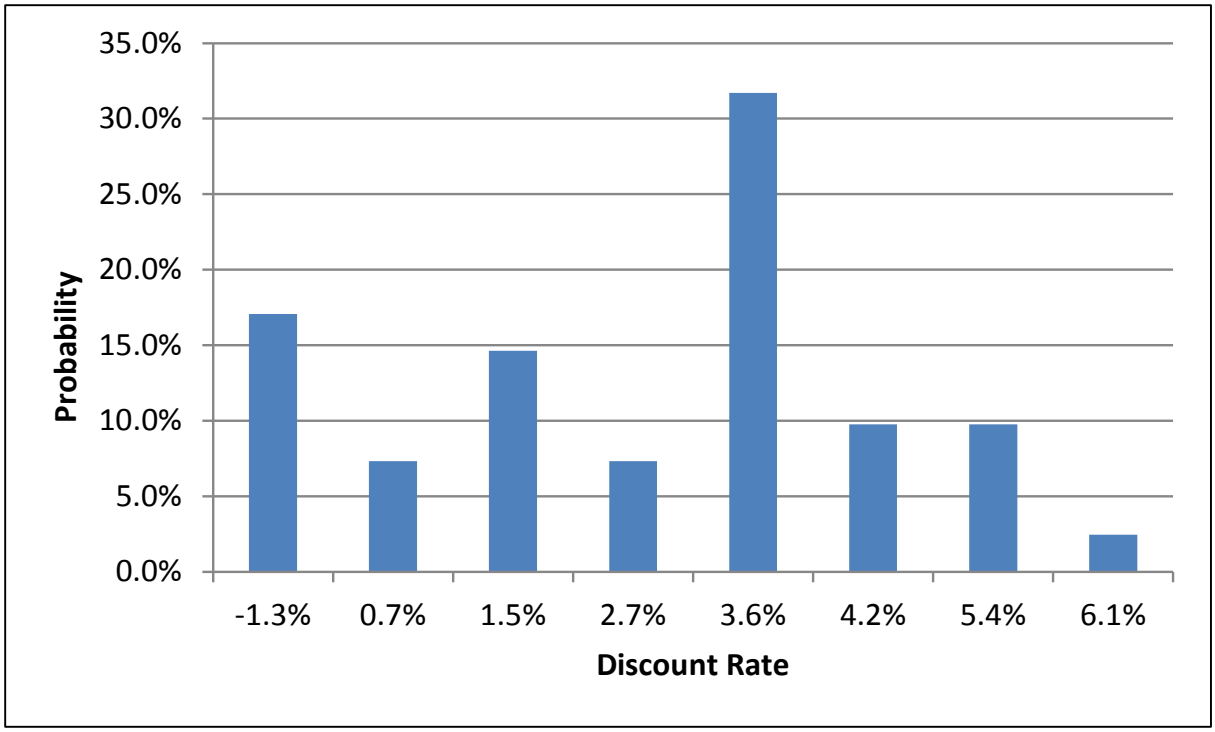

Figure 8G.2.8 Distribution of Commercial Discount Rates: State and Local Government

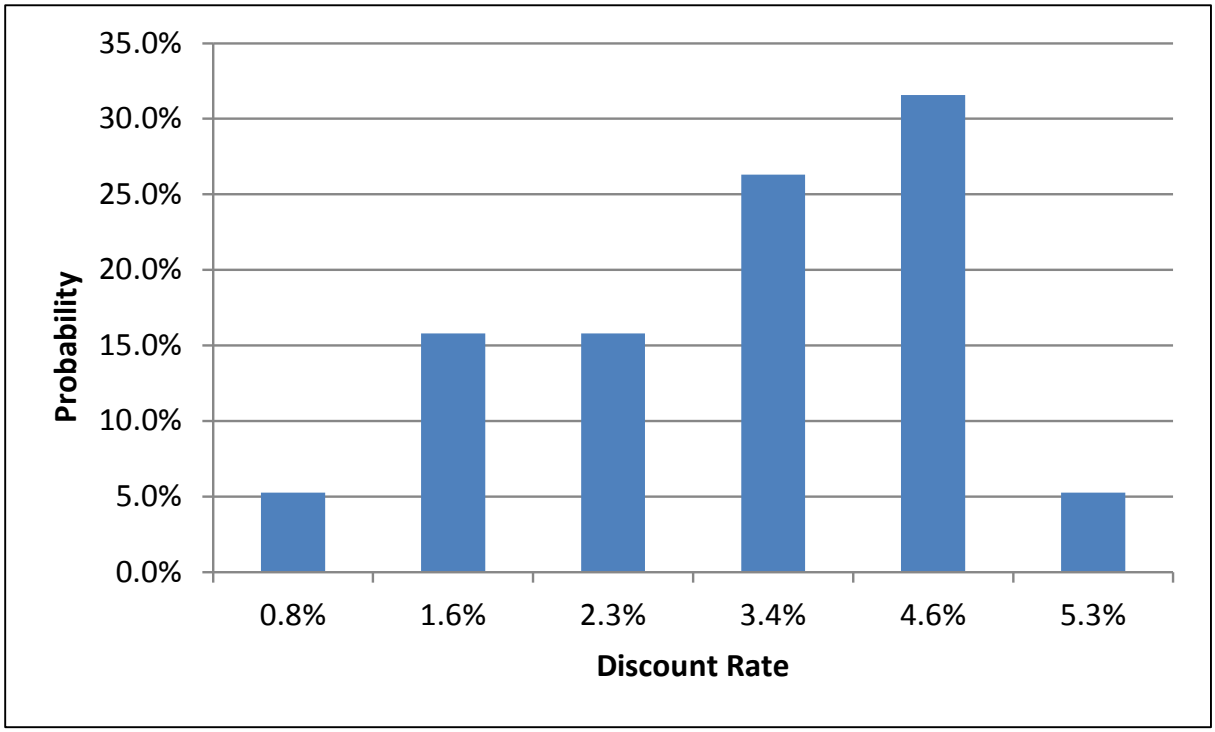

Figure 8G.2.9 Distribution of Commercial Discount Rates: Federal Government

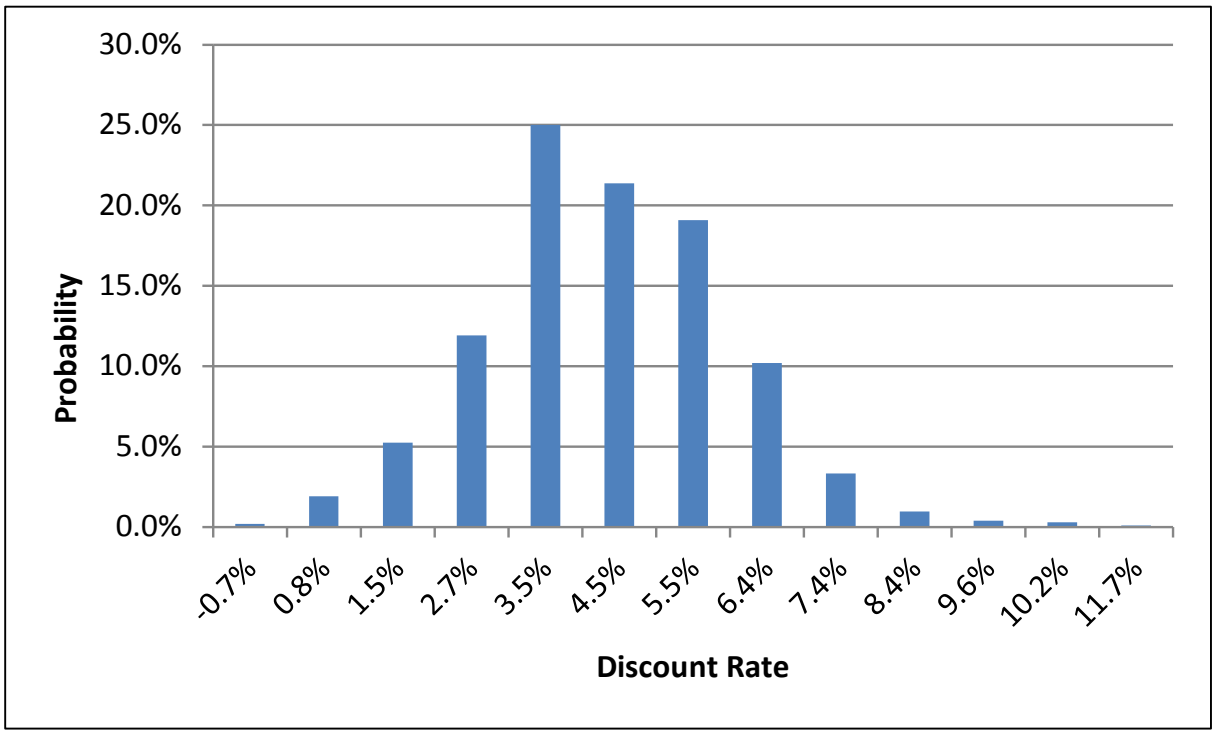

Figure 8G.2.10 Distribution of Commercial Discount Rates: Other

8G.3 DISTRIBUTIONS USED FOR CONSUMER DISCOUNT RATES

In the few residential applications of CWAF, the consumers are likely to be the building owners and not the actual household occupants. Therefore, the discount rates applied to replacement and new construction residential applications are the discount rates for property owners described in section 8G.2.

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APPENDIX 8H. LIFE-CYCLE COST ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

8H.1 INTRODUCTION 8H-1
8H.2 DESCRIPTION OF HIGH AND LOW ECONOMIC SCENARIOS 8H-1
8H.3 RESULTS 8H-2

LIST OF TABLES

Table 8H.3.1 Average LCC and PBB Results for High Economic Growth Scenario 8H-2
Table 8H.3.2 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for High Economic Growth Scenario 8H-2
Table 8H.3.3 Average LCC and PBB Results for Low Economic Growth Scenario..... 8H-3
Table 8H.3.4 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for Low Economic Growth Scenario..... 8H-3
Table 8H.3.5 Comparison of Average LCC Savings and Simple Payback Period Results for Reference Case and High and Low Economic Growth Scenarios 8H-4

APPENDIX 8H. LIFE-CYCLE COST ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR COMMERCIAL WARM AIR FURNACES

8H.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's (EIA's) *Annual Energy Outlook 2015* (*AEO 2015*).[1]

This appendix describes the High and Low Economic Growth scenarios in further detail. See appendix 8A for details about how to generate LCC results for High Economic Growth and Low Economic Growth scenarios using the LCC spreadsheet.

8H.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 in the Low Economic Growth scenario, and 2.9 percent in the High Economic Grow scenario.[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. To estimate energy prices after 2040 in the high and low scenarios, DOE used the growth rate between 2025 and 2040. In these graphs price trends after 2040 are presented with a dashed line, since 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 8C for details about how energy price trends by census division are applied in the LCC analysis.

8H.3 RESULTS

Table 8H.3.1 through Table 8H.3.4 summarizes the LCC and PBP results for High-Economic Growth and Low Economic Growth 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 (2019). Table 8H.3.5 compares average LCC savings and simple payback for these scenarios to the Reference case. The LCC and PBP results from the Reference, High-Economic Growth, and Low Economic Growth scenarios are similar. High-Economic Growth LCC and PBP savings are slightly higher compared to Reference and Low Economic Growth scenarios. Low Economic Growth savings are slightly lower compared to Reference case.

Table 8H.3.1 Average LCC and PBB Results for High Economic Growth Scenario

Equipment Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired CWAF	0	$2,087	$1,831	$30,019	$32,106	--	23
	1	$2,114	$1,812	$29,696	$31,811	1.4	23
	2	$2,543	$1,793	$29,384	$31,928	11.9	23
	3	$3,840	$1,671	$27,295	$31,135	11.0	23
Oil-Fired CWAF	0	$6,357	$3,054	$50,384	$56,742	--	23
	1	$6,410	$3,027	$49,911	$56,321	1.9	23
	2	$7,861	$2,851	$46,716	$54,578	7.4	23

Note: The analysis is for equipment purchased in 2019 for all TSLs. The results for each TSL are calculated assuming that all commercial consumers use equipment at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8H.3.2 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for High Economic Growth Scenario

Equipment Class	EL	Average LCC Savings* *2014$*	Percent of Consumers that Experience Net Cost
Gas-Fired CWAF	0	NA	--
	1	$297	5%
	2	$97	58%
	3	$885	56%
Oil-Fired CWAF	0	NA	--
	1	$412	11%
	2	$1,907	54%

Note: The analysis is for equipment purchased in 2019 for all TSLs.
* The savings represent the average LCC for affected consumers

Table 8H.3.3 Average LCC and PBB Results for Low Economic Growth Scenario

Equipment Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired CWAF	0	$2,087	$1,712	$27,926	$30,014	--	23
	1	$2,114	$1,694	$27,628	$29,743	1.5	23
	2	$2,543	$1,676	$27,340	$29,884	12.9	23
	3	$3,840	$1,565	$25,426	$29,266	12.0	23
Oil-Fired CWAF	0	$6,357	$2,984	$48,033	$54,390	--	23
	1	$6,410	$2,957	$47,583	$53,994	2.0	23
	2	$7,861	$2,785	$44,557	$52,418	7.6	23

Note: The analysis is for equipment purchased in 2019 for all TSLs. The results for each TSL are calculated assuming that all commercial consumers use equipment at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8H.3.4 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for Low Economic Growth Scenario

Equipment Class	EL	Average LCC Savings* *2014$*	Percent of Consumers that Experience Net Cost
Gas-Fired CWAF	0	NA	--
	1	$272	6%
	2	$55	59%
	3	$669	59%
Oil-Fired CWAF	0	NA	--
	1	$388	11%
	2	$1,730	54%

Note: The analysis is for equipment purchased in 2019 for all TSLs.
* The savings represent the average LCC for affected consumers

Table 8H.3.5 Comparison of Average LCC Savings and Simple Payback Period Results for Reference Case and High and Low Economic Growth Scenarios

Equipment Class	EL	Average LCC Savings *2014$*			Simple Payback Period *Years*		
		High Growth	Low Growth	Reference Case	High Growth	Low Growth	Reference Case
Gas-Fired CWAF	1	$297	$272	$284	1.4	1.6	1.4
	2	$97	$55	$75	11.9	12.9	12.3
	3	$885	$669	$766	11.0	12.0	11.3
Oil-Fired CWAF	1	$412	$388	$400	1.9	2.0	1.9
	2	$1,907	$1,730	$1,817	7.4	7.6	7.5

REFERENCES

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2. Energy Information Administration. Macroeconomic Activity Module. In *Assumptions to the Annual Energy Outlook 2015*. 2015. U. S. Energy Information Administration (EIA): Washington, D.C. http://www.eia.gov/forecasts/aeo/assumptions/pdf/macroeconomic.pdf.

CHAPTER 9. SHIPMENTS ANALYSIS

TABLE OF CONTENTS

9.1 INTRODUCTION 9-1
9.2 METHODOLOGY AND FUNDAMENTAL MODEL EQUATIONS 9-1
9.2.1 Methodology Overview 9-2
9.2.2 Shipments Model and Stock Equations in No-New-Standards Case 9-3
9.2.3 Price Elasticity 9-5
9.2.4 Shipments Model and Stock Equations in Standards Case 9-7
9.2.5 Estimation of Commercial Warm Air Furnace Shipments 9-11
9.3 DATA INPUTS AND SUPPORTING CALCULATIONS 9-15
9.3.1 Historical Shipments of Gas-Fired CWAFs 9-15
9.3.2 Historical Shipments of Oil-fired CWAFs 9-15
9.3.3 Survival Functions 9-17
9.4 SHIPMENTS PROJECTIONS 9-18
9.5 RESULTS 9-19

LIST OF TABLES

Table 9.5.1 Trial Standard Levels for Commercial Warm Air Furnaces by Efficiency Level 9-19
Table 9.5.2 Trial Standard Levels for Commercial Warm Air Furnaces by Thermal Efficiency 9-19

LIST OF FIGURES

Figure 9.3.1 Ratio of Oil-fired to Gas Residential Furnaces, 1970-2014 9-16
Figure 9.3.2 Ratio of Historical Shipments of Oil-fired vs. Gas-fired Residential Furnaces, 1993-2014 9-17
Figure 9.3.3 Survival Function for Functioning Stock 9-18
Figure 9.3.4 Survival Function for Extended Repairs 9-18
Figure 9.5.1 Historical Shipments of Commercial Warm Air Furnaces, 1970-2014 9-20
Figure 9.5.2 Projected Shipments in the No-New-Standards Case for TSLs 1, 3, 4, and 5 and the No-New-Standards Case for TSL 2 9-20
Figure 9.5.3 Projected Shipments of Gas-fired Commercial Warm Air Furnaces in the No-New-Standards Case and Each Standards Case, 2015-2048 9-21
Figure 9.5.4 Projected Shipments of Oil-fired Commercial Warm Air Furnaces in the No-New-Standards Case and Each Standards Case, 2015-2048 9-22

CHAPTER 9. SHIPMENTS ANALYSIS

9.1 INTRODUCTION

Estimates of future equipment 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 equipment shipments and presents results for commercial warm air furnace (CWAF) equipment classes being considered in this analysis.

The shipments model divides the shipments of CWAF into specific market segments. The model starts from a historical base year and calculates, for each year of the analysis period, both retirements and shipments by market segment. This approach produces an estimate of the total equipment stock, broken down by age or vintage, in each year of the analysis period. The shipment model also estimates the repaired or retired units. In addition, the equipment stock efficiency distribution is calculated for the case without amended standards (no-new-standards case) and for each standards case for each equipment class. The stock distribution is used in the national impact analysis (NIA) to estimate the total costs and benefits associated with each trial standard level (TSL).

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/70). 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 some summary output. The rest of the chapter describes the methodological approach.

9.2 METHODOLOGY AND FUNDAMENTAL MODEL EQUATIONS

The CWAF shipments model is based on shipments of commercial unitary air conditioners (CUAC) and commercial unitary heat pumps (CUHP) as determined in the 2015 CUAC/CUHP direct final rule.[1] The CWAF shipments model considers three equipment market segments (hereafter referred to as "market segments") as follows:

1. New buildings: a certain fraction of new buildings acquire the equipment in each year. This fraction is defined as the new construction saturation, which varies by year, region, and equipment class.
2. New owners: existing buildings acquiring the equipment for the first time.
3. Replacements (existing owners): existing buildings with the equipment installed. This category receives new shipments when existing equipment is replaced.

Section 9.2.1 presents an overview of methodology for the shipments analysis. Section 9.2.2 describes the shipments model and stock equations in the no-new-standards case. Section 9.2.3 describes the price elasticity methodology used to calculate shipments under the standards cases. Section 9.2.4 describes the shipments model and stock equations in the standards case. Refer to chapter 9 of the CUAC/CUHP direct final rule technical support document (TSD) for more details on price-elasticity-based shipments analysis methodology.[1] Section 9.2.5 describes how CUAC/CUHP shipments are applied to estimate CWAF shipments.

9.2.1 Methodology Overview

The shipments model is used to calculate the number of units shipped in each year of the analysis period, the stock of functioning (never repaired) equipment, and the stock of extended-lifetime (repaired once) equipment. Shipments forecasts are calculated for three market segments namely (a) new buildings, *i.e.*, new commercial buildings acquiring equipment, (b) new owners, *i.e.*, existing buildings acquiring equipment for the first time, and (c) existing building replacing broken units.

For new buildings (*i.e.*, new commercial buildings acquiring equipment) and new owners (*i.e.*, existing buildings acquiring new equipment for the first time), DOE estimated the gas-fired CWAF shipments to new buildings and new owners based on the CUAC/CUHP shipments to the new buildings and new owners, respectively. DOE then estimated the oil-fired CWAF shipments to new buildings and new owners according to the ratio of oil-fired CWAF shipments to gas-fired CWAF shipments.

For existing buildings replacing broken equipment, the shipments model uses a stock accounting framework. Given the equipment entering the stock in each year and a survival function based on the equipment lifetime distribution, the model predicts how many units reach the end of their lifetime in each year. DOE typically refers to new shipments intended to replace retired units as replacement shipments. Such shipments are usually the largest part of total shipments.

For broken units, the commercial consumer has the choice of repairing the existing unit, thereby extending its life considerably, or purchasing a new unit. A new unit is usually more expensive than repairing the existing unit, but it may be more energy-efficient than the existing unit, which means it would have lower operating costs. If standards increase the cost of new equipment, one would expect that the repair option would become more attractive, resulting in a drop in shipments. The decision to repair or replace broken or retired units would depend on consumer sensitivity to the price of a new unit as defined by a market sales *elasticity* parameter.

Repaired units have their lifetime extended, and the shipments model does the stock accounting for repaired units according to an extended repair survival function. If a repaired unit encounters its second failure, the model assumes that the commercial consumer replaces the unit with a new one.

The methods described above estimated total shipments for each year. DOE also estimated the market shares of the considered ELs in future shipments (see chapter 10 for more details).

9.2.2 Shipments Model and Stock Equations in No-New-Standards Case

The shipments model is used to calculate the number of units shipped and the stock of equipment. Shipments are disaggregated into three market segments, as shown in Eq. 9.1:

$$S(y) = S_N(y) + S_E(y) + S_R(y)$$

Eq. 9.1

Where:

$S(y)$ = total equipment shipments in year y,
$S_N(y)$ = shipments to new buildings in year y,
$S_E(y)$ = shipments to new owners in existing buildings in year y, and
$S_R(y)$ = shipments to existing buildings to replace broken or retired stock in year y.

In the no-new-standards case, the CWAF shipments were estimated based on the shipments of CUAC and CUHP as determined in the 2015 CUAC/CUHP direct final rule. Specifically, DOE estimated the ratios of gas-fired CWAF shipments to the CUAC and CUHP shipments, and then estimated the gas-fired CWAF shipments to new buildings, new owners in existing buildings, existing buildings to replace broken or retired stock based on the ratios and the CUAC and CUHP shipments to new buildings, new owners in existing buildings, existing buildings to replace broken or retired stock, respectively. The oil-fired CWAF shipments were estimated based on the ratio of oil-fired CWAF shipments to gas-fired CWAF shipments. See section 9.2.5 for more details.

The stock equations are used to describe changes in the distribution of stock from year y to year y +1. In the no-new-standards case, the total stock $U(y)$ in a given year y can be separated into (1) functioning stock carried over from the previous year, and (2) total shipments in the given year:

$$U(y) = \sum_{v<y} U_F(y,v) + S(y)$$

Eq. 9.2

Where:

$U_F(y, v)$ = functioning stock carried over from the previous year,
$S(y)$ = total shipments in the given year y, and
v = vintage of the equipment; corresponds to the year in which a unit was shipped.

By definition, the functioning stock of vintage $v < y$ corresponds to all surviving stock from the previous year.

The functioning stock in year y of vintage v, denoted as $U_F(y, v)$, corresponds to surviving stock carried over from the previous year and is given by the expression:

$$U_F(y,v) = \begin{cases} \sigma_F(a) \times U_F(y-1,v); & if\ v = y-1 \\ \sigma_F(a)/\sigma_F(a-1) \times U_F(y-1,v); & if\ v < y-1 \end{cases}$$

Eq. 9.3

Where:

a = age of stock of vintage v in year y, which is equal to $y - v$, and
$\sigma_F(a)$ = "survival function" for functioning stock; represents the fraction of stock of age a that does not break.

The "non-survival" function for functioning stock is $1 - \sigma_F(a)$. This is the fraction of stock of age a that breaks.

The probability that equipment will survive up to an age a is given by a Weibull cumulative distribution function:

$$\sigma_F(a;k,\gamma,\lambda) = 1 - e^{\left(\frac{a-\gamma}{\lambda}\right)^k}$$

Eq. 9.4

Where:

k, γ, λ = shape, location (delay), and scale parameters, respectively.

The functioning stock of vintage $v = y$ is the shipments $S(y)$ in year y, which is given by the equation:

$$U_F(y, v = y) = S(y)$$

Eq. 9.5

Broken stock, denoted as $U_B(y,v)$, represents equipment of vintage v that does not survive in year y, which is given by the equation:

$$U_B(y,v) = U_F(y-1,v) - U_F(y,v)$$

Eq. 9.6

Eq. 9.5 and Eq. 9.6 are subject to the initial conditions:

$$U_F(y_0, v = v_0) = S(y_0)$$

Eq. 9.7

$$U_B(y_0, v) = 0$$

Eq. 9.8

Where:

y_0 = first year of the analysis, *i.e.*, the first year for the which the drivers and/or historical shipments are present,
v_0 = vintage in year y_0, and
$S(y_0) = S_N(y_0)$ because $S_E(y_0)$ and $S_R(y_0)$ are both zero for year y_0.

For the no-new-standards case, repairs are assumed to be non-policy related and accounted for by the survival function $\sigma_F(a)$. The shipments for replacements are therefore expressed as:

$$S_R(y) = \sum_v U_B(y, v)$$

Eq. 9.9

9.2.3 Price Elasticity

For broken units, the commercial consumer has the choice of repairing the existing unit, thereby extending its life considerably, or purchasing a new unit. A new unit is usually more expensive than repairing the existing unit, but it may be more energy-efficient than the existing unit, which means it would have lower operating costs. If standards increase the cost of new equipment, one would expect that the repair option would become more attractive, resulting in a drop in shipments. The decision to repair or replace broken or retired units would depend on consumer sensitivity to the price of a new unit as defined by a market sales *elasticity* parameter.

The relative price elasticity ε is defined by the equation:

$$\varepsilon = \left(\frac{\delta S_L}{S_0} \right) \Big/ \left(\frac{\delta \Pi_L}{\Pi_0} \right)$$

Eq. 9.10

Where:

L = TSL, with $L = 0$ denoting the no-new-standards case,
S_0 = total number of units shipped for no-new-standards case,
S_L = total number of units shipped for TSL L,
Π_0 = price utility (defined in Eq. 9.11) for the no-new-standards case,
Π_L = price utility for TSL L,
$\frac{\delta S_L}{S_0}$ = change in the total number of units shipped for TSL L relative to the no-new-standards case, and

$\frac{\delta \Pi_L}{\Pi_0}$ = change in the price utility for TSL L relative to the no-new-standards case.

For this analysis, the elasticity is negative; hence, shipments drop with an increase in price resulting from the application of the standard. For equipment used in the commercial sector, the value of ε is assumed to be −0.68, which is twice the value of the purchase price elasticity used for residential products (−0.34).[2] The higher elasticity reflects generally higher commercial consumer sensitivity to purchase price for equipment in the commercial sector. The price utility function depends on the attributes of the appliance and is defined as

$$\Pi_L = \frac{P_L + IC_L + \beta \times AOC_L}{I_L}$$

Eq. 9.11

Where:

P_L = annual equipment retail price corresponding to TSL L,
IC_L = annual equipment installation cost,
AOC_L = annual equipment operating cost,
I_L = annual commercial consumer income, and
β = a parameter representing the implicit discount rate that is summed over the equipment lifetime and given by the expression:

$$\beta = \sum_{i=0}^{N} \frac{1}{(1+d)^i}$$

Eq. 9.12

Where:

N = equipment lifetime in years, and
d = implicit discount rate on future cost savings.[a]

The annual operating cost is equal to the annual energy use times a (constant) annual energy price escalation factor e. This factor can be incorporated into β by defining

$$\beta' = \sum_{i=0}^{N} \frac{(1+e)^i}{(1+d)^i}$$

Eq. 9.13

[a] The implicit discount rate is the rate of discounting implied by a consumer's choices across investments with differing rates of return; in the case of furnaces, the energy cost savings offered by equipment of different efficiency levels may be viewed as investments with different rates of return. For example, as described by Train (1985), "if six different actions can be taken that offer rates of return of, say, 18%, 16%, 15%, 13%, 9%, and 4%, respectively, and the consumer chooses those with 18%, 16%, and 15% returns but none of the others, then one can infer that the consumer's [implicit] discount rate is between 15 and 13%."[3–5]

Therefore, Eq. 9.11 becomes

$$\Pi_L = \frac{P_L + IC_L + \beta' \times AOC_L}{I_L}$$

Eq. 9.14

Typically, the purchase price is a function of TSL L and year y because of the "price-learning effect" represented by an annual factor $\gamma(y - y_s)$ and also specific equipment-dependent attributes. DOE assumed that the same learning applies in the no-new-standards case and in the standards case. Installation costs may also vary with TSL and other product-specific attributes; they may also change over time, but that effect is not normally included in the analysis.

While average income may vary with time, this factor divides out of the ratio in Eq. 9.10. The annual operating cost depends on TSL and on equipment specific attributes. A detailed expression for the change in the price utility can be expressed as:

$$\frac{\delta \Pi_L}{\Pi_0} = \Delta_L(y) = \frac{P_L \times \gamma(y - y_s) + IC_L + \beta' \times AOC_L}{P_0 \times \gamma(y - y_s) + IC_0 + \beta' \times AOC_0} - 1$$

Eq. 9.15

The methodology used for residential appliances also assumes that the price elasticity in Eq. 9.10 changes with time[2]; this means that the impact of a step change in price in a given year decreases in later years. The time series of this scaling factor, defined as $h(y - y_s)$, drops rapidly in the first few years to a value of about one-third.

9.2.4 Shipments Model and Stock Equations in Standards Case

For the no-new-standards case and each TSL, the total shipments of equipment in a given year y can be reformulated as:

$$S_L(y) = S_{L,N}(y) + S_{L,E}(y) + S_{L,R}(y)$$

Eq. 9.16

Where:

L = TSL, with $L = 0$ denoting the no-new-standards case,
$S_L(y)$ = total equipment shipments in year y for TSL L,
$S_{L,N}(y)$ = shipments to new buildings in year y for TSL L,
$S_{L,E}(y)$ = shipments to new owners in existing buildings for TSL L, and
$S_{L,R}(y)$ = shipments to existing buildings to replace broken or retired units in year y for TSL L.

In the standards case, the CWAF shipments to new buildings and new owners in existing buildings were estimated based on the shipments of CUAC and CUHP as determined in the 2015

CUAC/CUHP direct final rule. Specifically, DOE estimated the ratios of gas-fired CWAF shipments to the CUAC and CUHP shipments, and then estimated the gas-fired CWAF shipments to new buildings and new owners in existing buildings based on the ratios and the CUAC and CUHP shipments to new buildings and new owners in existing buildings, respectively. The oil-fired CWAF shipments to new buildings and new owners in existing buildings were estimated based on the ratio of oil-fired CWAF shipments to gas-fired CWAF shipments to new buildings and new owners in existing buildings, respectively. See section 9.2.5 for more details.

The shipments for replacements are price elastic. The drop in the shipments for replacements at TSL L, denoted as $\delta S_{L,R}(y)$, is given by:

$$\delta S_{L,R}(y) = S_{0,R}(y) \times h(y - y_s) \times |\varepsilon| \times \Delta_L(y)$$

Eq. 9.17

Where:

$S_{0,R}(y)$ = shipments for replacements in the no-new-standards case,
ε = relative price elasticity,
y_s = compliance year of the standards,
$h(y - y_s)$ = scaling factor for relative price elasticity, and
$\Delta_L(y)$ = change in price utility.

Assuming that consumers who have such equipment do not want to give up the service provided by the equipment, this drop in replacement shipments must be compensated by additional repairs. Hence, in each year the extended-repair stock is equal to $\delta S_{L,R}$.

Shipments for replacements in the standards case are hence calculated from stock failures that involve replacements from (1) non-repaired broken or retired stock that is replaced, and (2) extended-repair stock that breaks again.

The shipments for replacements can then be expressed as:

$$S_{L,R}(y) = S_{L,R}^{\mathrm{T1}}(y) + S_{L,R}^{\mathrm{T2}}(y)$$

Eq. 9.18

Where:

$S_{L,R}^{\mathrm{T1}}(y)$ = non-repaired broken stock that is replaced, and
$S_{L,R}^{\mathrm{T2}}(y)$ = extended-repair stock (or excess repairs) that breaks again.

The total stock $U_L(y)$ in a given year y for TSL L can be separated into (1) functioning stock carried over from the previous year, (2) total shipments in the given year, and (3) stock whose life has been extended through repairs:

$$U_L(y) = \sum_{v<y} U_{L,F}(y,v) + S_L(y) + \sum_{v} \sum_{y_r} X_L(y,v,y_r)$$

Eq. 9.19

Where:

$U_{L,F}(y, v)$ = functioning stock carried over from the previous year for TSL L,
$S_L(y)$ = total shipments in the given year for TSL L,
$X_L(y, v, y_r)$ = stock whose life has been extended through repairs for TSL L, and
y_r = year in which a broken unit is repaired.

The age a_r of a repaired unit is defined as $a_r = y_r - v$. a_r is assumed to be greater than 0, *i.e.*, stock cannot break down in the same year it was shipped.

The functioning stock in year y of vintage v for TSL L, denoted as $U_{L,F}(y, v)$, corresponds to surviving stock carried over from the previous year and is given by the expression:

$$U_{L,F}(y,v) = \begin{cases} \sigma_F(a) \times U_{L,F}(y-1,v); & if\ v = y-1 \\ \sigma_F(a)/\sigma_F(a-1) \times U_{L,F}(y-1,v); & if\ v < y-1 \end{cases}$$

Eq. 9.20

Where:

$a = y - v$, and
$\sigma_F(a)$ = "survival function" for functioning stock.

The "non-survival" function for functioning stock is $1 - \sigma_F(a)$. The probability that equipment will survive up to an age a is given by a Weibull cumulative distribution function defined in Eq. 9.4.

The functioning stock of vintage $v = y$ is the shipments $S_L(y)$ in year y, which is given by the equation:

$$U_{L,F}(y, v = y) = S_L(y)$$

Eq. 9.21

Broken stock, denoted as $U_{L,B}(y,v)$, represents equipment of vintage v that does not survive in year y, which is given by the equation:

$$U_{L,B}(y,v) = U_{L,F}(y-1,v) - U_{L,F}(y,v)$$

Eq. 9.22

Eq. 9.20 and Eq. 9.22 are subject to the initial conditions:

$$U_{L,F}(y_0, v = v_0) = S_L(y_0)$$

Eq. 9.23

$$U_{L,B}(y_0, v) = 0$$

Eq. 9.24

Where:

y_0 = first year of the analysis, *i.e.*, the first year for the which the drivers and/or historical shipments are present,
v_0 = vintage in year y_0, and
$S_L(y_0) = S_{L,N}(y_0)$ because $S_{L,E}(y_0)$ and $S_{L,R}(y_0)$ are both zero for year y_0.

The shipments and stock equations in the standards cases are identical to those in the no-new-standards case for years $y < y_s$. For $y \geq y_s$, changes to the shipments, and in particular shipments for replacements, arise due to decisions made by consumers to *repair* broken units instead of replacing them as a result of a price increase due to the standard. Hence, this impacts the vintage distributions of both the functioning and broken stock by apportioning a fraction of broken stock vintages to repairs, thereby also decreasing the number of shipments for replacements. In each year, this fraction is equal to $\Delta_L(y)$ and broken stock vintages that get repairs have their lifetimes extended by a maximum of years.

As shown in Eq. 9.18, the shipments for replacements come from two terms: $S_{L,R}^{T1}(y)$ denoting non-repaired broken stock that gets replaced, and $S_{L,R}^{T2}(y)$ denoting extended-repair stock that breaks again.

The fraction of broken stock getting life-extending repairs is given by the expression

$$X_L(y, v, y_r = y) = U_{L,B}(y, v) \times |\varepsilon| \times h(y - y_s) \times \Delta_L(y)$$

Eq. 9.25

The non-repaired broken stock that gets replaced can be expresses as:

$$S_{L,R}^{T1}(y) = \sum_v \left[1 - |\varepsilon| \times h(y - y_s) \times \Delta_L(y)\right] \times U_{L,B}(y, v)$$

Eq. 9.26

Because the compliance year y_s is the first year in which broken stock gets repaired, the contribution of extended-repair stock that breaks again to the shipments for replacements is zero in year y_s.

For $y > y_s$, the extended-repair stock $X_L(y, v, y_r)$, ages according to the extended repair survival function $\sigma_X(a_r)$:

$$X_L(y,v,y_r) = \begin{cases} \sigma_X(y-y_r) \times X_L(y-1,v,y_r); & if\ y_r = y-1 \\ \sigma_X(y-y_r)/\sigma_X(y-y_r-1) \times X_L(y-1,v,y_r); & if\ y_r < y-1 \end{cases}$$

Eq. 9.27

The extended repair stock for $y = y_r$ is given by Eq. 9.25. Extended-repair stock that breaks again in a given year and contributes towards shipments for replacements is given by the expression:

$$S_{L,R}^{\mathrm{T2}}(y) = \sum_v \sum_{y_r} X_L(y-1,v,y_r) - X_L(y,v,y_r)$$

Eq. 9.28

The shipments for replacements for year y are then:

$$\begin{aligned} S_{L,R}(y) &= S_{L,R}^{\mathrm{T1}}(y) + S_{L,R}^{\mathrm{T2}}(y) \\ &= \left\{ \sum_v \left[1 - |\varepsilon| \times h(y-y_s) \times \Delta_L(y)\right] \times U_{L,B}(y,v) \right\} \\ &\quad + \left\{ \sum_v \sum_{y_r} X_L(y-1,v,y_r) - X_L(y,v,y_r) \right\} \end{aligned}$$

Eq. 9.29

9.2.5 Estimation of Commercial Warm Air Furnace Shipments

The CWAF shipments model and estimations use CUAC/CUHP shipments as inputs to coordinate the CWAF standards with the CUAC/CUHP standards.

<u>No-New-Standards Case (L = 0)</u>

For the no-new-standards case ($L = 0$), the CWAF shipments were estimated based on the shipments of CUAC and CUHP as determined in the 2015 CUAC/CUHP direct final rule. Specifically, the gas-fired CWAF shipments were estimated using the following equations:

$$S_0^{Gas}(y) = S_{0,N}^{Gas}(y) + S_{0,E}^{Gas}(y) + S_{0,R}^{Gas}(y)$$

Eq. 9.30

$$S_{0,N}^{Gas}(y) = \left(\theta_{CUAC}^{Gas}(y) \times S_{L',N}^{CUAC}(y) + \theta_{CUHP}^{Gas}(y) \times S_{L',N}^{CUHP}(y)\right) / \left(1 - \theta_{Indoor}^{Gas}(y)\right)$$

Eq. 9.31

$$S_{0,E}^{Gas}(y) = \left(\theta_{CUAC}^{Gas}(y) \times S_{L',E}^{CUAC}(y) + \theta_{CUHP}^{Gas}(y) \times S_{L',E}^{CUHP}(y)\right) / \left(1 - \theta_{Indoor}^{Gas}(y)\right)$$

Eq. 9.32

$$S_{0,R}^{Gas}(y) = \left(\theta_{CUAC}^{Gas}(y) \times S_{L',R}^{CUAC}(y) + \theta_{CUHP}^{Gas}(y) \times S_{L',R}^{CUHP}(y)\right) / \left(1 - \theta_{Indoor}^{Gas}(y)\right)$$

Eq. 9.33

Where:

$S_0^{Gas}(y)$ = total gas-fired CWAF shipments to new buildings in year y for the no-new-standards case,

L' = TSL for CUAC/CUHP standards, with L' = 0 denoting the no-new-CUAC/CUHP-standards case. L' is equal to the Recommended TSL for CUAC/CUHP standards for no-new-standards case for CWAF TSL 2, and is equal to the no-new-CUAC/CUHP-standards case (*i.e.*, L' = 0) for no-new-standards case for all other CWAF TSLs (*i.e.*, CWAF TSL 1, 3, 4, and 5),

$S_{0,N}^{Gas}(y)$ = gas-fired CWAF shipments to new buildings in year y for the no-new-standards case,

$S_{L',N}^{CUAC}(y)$ and $S_{L',N}^{CUHP}(y)$ = CUAC and CUHP shipments to new buildings in year y for the CUAC/CUHP standards case L', respectively.

$S_{0,E}^{Gas}(y)$ = gas-fired CWAF shipments to existing buildings acquiring the equipment for the first time in year y for the no-new-standards case,

$S_{L',E}^{CUAC}(y)$ and $S_{L',E}^{CUHP}(y)$ = CUAC and CUHP shipments to existing buildings acquiring the equipment for the first time in year y for the CUAC/CUHP standards case L', respectively,

$S_{0,R}^{Gas}(y)$ = gas-fired CWAF shipments to existing buildings for the purpose of replacing broken or retired units in year y for the no-new-standards case,

$S_{L',R}^{CUAC}(y)$ and $S_{L',R}^{CUHP}(y)$ = CUAC and CUHP shipments to existing buildings for the purpose of replacing broken or retired units in year y for the CUAC/CUHP standards case L', respectively,

$\theta_{CUAC}^{Gas}(y)$ = ratio of gas-fired CWAF shipments to CUAC shipments in year y (see section 9.3.1),

$\theta_{CUHP}^{Gas}(y)$ = ratio of gas-fired CWAF shipments to CUHP shipments in year y (see section 9.3.1), and

$\theta_{Indoor}^{Gas}(y)$ = ratio of indoor gas-fired CWAF shipments to the total gas-fired CWAF shipments in year y (see section 9.3.1).

The oil-fired CWAF shipments were estimated using the following equations:

$$S_0^{Oil}(y) = S_{0,N}^{Oil}(y) + S_{0,E}^{Oil}(y) + S_{0,R}^{Oil}(y)$$

Eq. 9.34

$$S_{0,N}^{Oil}(y) = \theta_{Gas}^{Oil}(y) \times S_{0,N}^{Gas}(y)$$

Eq. 9.35

$$S_{0,E}^{Oil}(y) = \theta_{Gas}^{Oil}(y) \times S_{0,E}^{Gas}(y)$$

Eq. 9.36

$$S_{0,R}^{Oil}(y) = \theta_{Gas}^{Oil}(y) \times S_{0,R}^{Gas}(y)$$

Eq. 9.37

Where:

$S_0^{Oil}(y)$ = total oil-fired CWAF shipments to new buildings in year y for the no-new-standards case,

$S_{0,N}^{Oil}(y)$ = oil-fired CWAF shipments to new buildings in year y for the no-new-standards case,

$S_{0,E}^{Oil}(y)$ = oil-fired CWAF shipments to existing buildings acquiring the equipment for the first time in year y for the no-new-standards case,

$S_{0,R}^{Oil}(y)$ = oil-fired CWAF shipments to existing buildings for the purpose of replacing broken or retired units in year y for the no-new-standards case, and

$\theta_{Gas}^{Oil}(y)$ = ratio of oil-fired CWAF shipments to the gas-fired CWAF shipments in year y (see section 9.3.2).

<u>Standards Case (L > 0)</u>

For the standards case ($L > 0$), the gas-fired CWAF shipments were estimated using the following equations based on price elasticity impacts:

$$S_L^{Gas}(y) = S_{L,N}^{Gas}(y) + S_{L,E}^{Gas}(y) + S_{L,R}^{Gas}(y)$$

Eq. 9.38

$$S_{L,N}^{Gas}(y) = \left(\theta_{CUAC}^{Gas}(y) \times S_{L',N}^{CUAC}(y) + \theta_{CUHP}^{Gas}(y) \times S_{L',N}^{CUHP}(y)\right) / \left(1 - \theta_{Indoor}^{Gas}(y)\right)$$

Eq. 9.39

$$S_{L,E}^{Gas}(y) = \left(\theta_{CUAC}^{Gas}(y) \times S_{L',E}^{CUAC}(y) + \theta_{CUHP}^{Gas}(y) \times S_{L',E}^{CUHP}(y)\right) / \left(1 - \theta_{Indoor}^{Gas}(y)\right)$$

Eq. 9.40

$$S_{L,R}^{Gas}(y) = S_{L,R}^{Gas,\mathrm{T1}}(y) + S_{L,R}^{Gas,\mathrm{T2}}(y)$$

Eq. 9.41

Where:

$S_L^{Gas}(y)$ = total gas-fired CWAF shipments to new buildings in year y for the CWAF standards case L,

L' = TSL for CUAC/CUHP standards, with $L' = 0$ denoting the no-new-CUAC/CUHP-standards case. L' is equal to the Recommended TSL for CUAC/CUHP standards for CWAF TSL 2 (*i.e.*, L' = Recommended TSL for $L = 2$), and is equal to the no-new-CUAC/CUHP-standards case for all other CWAF TSLs (*i.e.*, $L' = 0$ for $L = 1, 3, 4$, and 5),

$S_{L,N}^{Gas}(y)$ = gas-fired CWAF shipments to new buildings in year y for the CWAF standards case L,

$S_{L',N}^{CUAC}(y)$ and $S_{L',N}^{CUHP}(y)$ = CUAC and CUHP shipments to new buildings in year y for the CUAC/CUHP standards case L', respectively,

$S_{L,E}^{Gas}(y)$ = gas-fired CWAF shipments to existing buildings acquiring the equipment for the first time in year y for the CWAF standards case L,
$S_{L',E}^{CUAC}(y)$ and $S_{L',E}^{CUHP}(y)$ = CUAC and CUHP shipments to existing buildings acquiring the equipment for the first time in year y for the CUAC/CUHP standards case L', respectively,
$S_{L,R}^{Gas}(y)$ = gas-fired CWAF shipments to existing buildings for the purpose of replacing broken or retired units in year y for the CWAF standards case L, referring to Eq. 9.29,
$S_{L,R}^{Gas,\mathrm{T1}}(y)$ = non-repaired broken gas-fired CWAF stock that gets replaced in year y for the CWAF standards case L, referring to Eq. 9.26, and
$S_{L,R}^{Gas,\mathrm{T2}}(y)$ = Extended-repair gas-fired CWAF stock that breaks again and gets replaced in year y for the CWAF standards case L, referring to Eq. 9.28.

The oil-fired CWAF shipments were also estimated using the following equations based on price elasticity impacts:

$$S_{L}^{Oil}(y) = S_{L,N}^{Oil}(y) + S_{L,E}^{Oil}(y) + S_{L,R}^{Oil}(y)$$

Eq. 9.42

$$S_{L,N}^{Oil}(y) = \theta_{Gas}^{Oil}(y) \times S_{L,N}^{Gas}(y)$$

Eq. 9.43

$$S_{L,E}^{Oil}(y) = \theta_{Gas}^{Oil}(y) \times S_{L,E}^{Gas}(y)$$

Eq. 9.44

$$S_{L,R}^{Oil}(y) = S_{L,R}^{Oil,\mathrm{T1}}(y) + S_{L,R}^{Oil,\mathrm{T2}}(y)$$

Eq. 9.45

Where:

$S_{L}^{Oil}(y)$ = total oil-fired CWAF shipments to new buildings in year y for the CWAF standards case L,
$S_{L,N}^{Oil}(y)$ = oil-fired CWAF shipments to new buildings in year y for the CWAF standards case L,
$S_{L,E}^{Oil}(y)$ = oil-fired CWAF shipments to existing buildings acquiring the equipment for the first time in year y for the CWAF standards case L,
$S_{L,R}^{Oil}(y)$ = oil-fired CWAF shipments to existing buildings for the purpose of replacing broken or retired units in year y for the CWAF standards case L, referring to Eq. 9.29,
$S_{L,R}^{Oil,\mathrm{T1}}(y)$ = non-repaired broken oil-fired CWAF stock that gets replaced in year y for the CWAF standards case L, referring to Eq. 9.26, and
$S_{L,R}^{Oil,\mathrm{T2}}(y)$ = extended-repair oil-fired CWAF stock that breaks again and gets replaced in year y for the CWAF standards case L, referring to Eq. 9.28.

9.3 DATA INPUTS AND SUPPORTING CALCULATIONS

9.3.1 Historical Shipments of Gas-Fired CWAFs

Historical shipments data for CWAF equipment are very limited. According to a report from Pacific Northwest National Laboratory (PNNL),[6] the Air-conditioning, Heating, and Refrigeration Institute (AHRI) [b] reported the shipments of gas-fired CWAF in 1994 to be 164,300.

Most gas-fired CWAF are installed as an integral part of a combined packaged cooling and heating outdoor unit, typically rooftop mounted, which are subset of the CUAC equipment.[c] Because separate shipments data for gas-fired CWAFs was only available for 1994, DOE used historical shipments data of CUAC and an estimated ratio of gas-fired CWAFs to total CUAC shipments to populate its shipments model for gas-fired CWAFs. Base on AHRI shipments data for gas-fired CWAFs in 1994, the ratio of gas-fired CWAF to CUAC shipments was calculated to be 80 percent in 1994. In addition, DOE determined based on Commercial Buildings Energy Consumption Survey (CBECS) 2003 data that some buildings have both CUHP and gas-fired CWAF installed.[7] The gas-fired CWAF in these buildings could be non-weatherized units (which are not packaged with a CUAC or CUHP). Based on CBECS 2003 data, DOE estimated that gas-fired CWAF shipments are the sum of approximately 80 percent of CUAC shipments and 20 percent of CUHP shipments.

DOE believes that these ratios should be relatively stable over time. Therefore, DOE determined the historical shipments of gas-fired CWAF by multiplying the ratios of CWAF units by the historical shipments of CUAC and CUHP. DOE used 80 percent as the ratio of CWAF shipments to the CUAC shipments and 20 percent as the ratio CWAF shipments to the CUHP shipments, as described previously. Based CEBCS 2003 data, DOE estimated that 95 percent of gas-fired CWAFs are outdoor unit package inside a CUAC unit, while the remaining 5 percent are indoor units.

9.3.2 Historical Shipments of Oil-fired CWAFs

Shipments data for oil-fired CWAFs is not publically available. Based on residential furnace shipments data provided by AHRI,[8] DOE calculated the ratio of oil-fired residential furnaces compared to shipments of gas-fired residential furnaces.[d,8–10] Figure 9.3.1 shows the historical shipments of residential gas-fired residential furnaces and oil-fired residential furnaces and the resulting ratio of oil-fired residential furnaces to gas-fired residential furnaces. As shown in Figure 9.3.2, the ratio of oil-fired residential furnaces to gas-fired residential furnaces

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[b] Previously Gas Appliance Manufacturers Association (GAMA).
[c] As mentioned in chapter 3, most gas-fired CWAF are weatherized and share a common cabinet with a CUAC, but not with a CUHP.
[d] Includes residential non-weatherized gas furnaces, mobile home gas furnaces, and weatherized gas furnaces.

decreased over time from 1993-2014. DOE assumed that the ratio of oil-fired residential furnaces to gas-fired residential furnaces would be about 1 percent after 2014.

DOE applied the ratio of oil-fired residential furnaces to gas-fired residential furnaces to the shipments of gas-fired CWAF to determine the shipments of oil-fired CWAF.

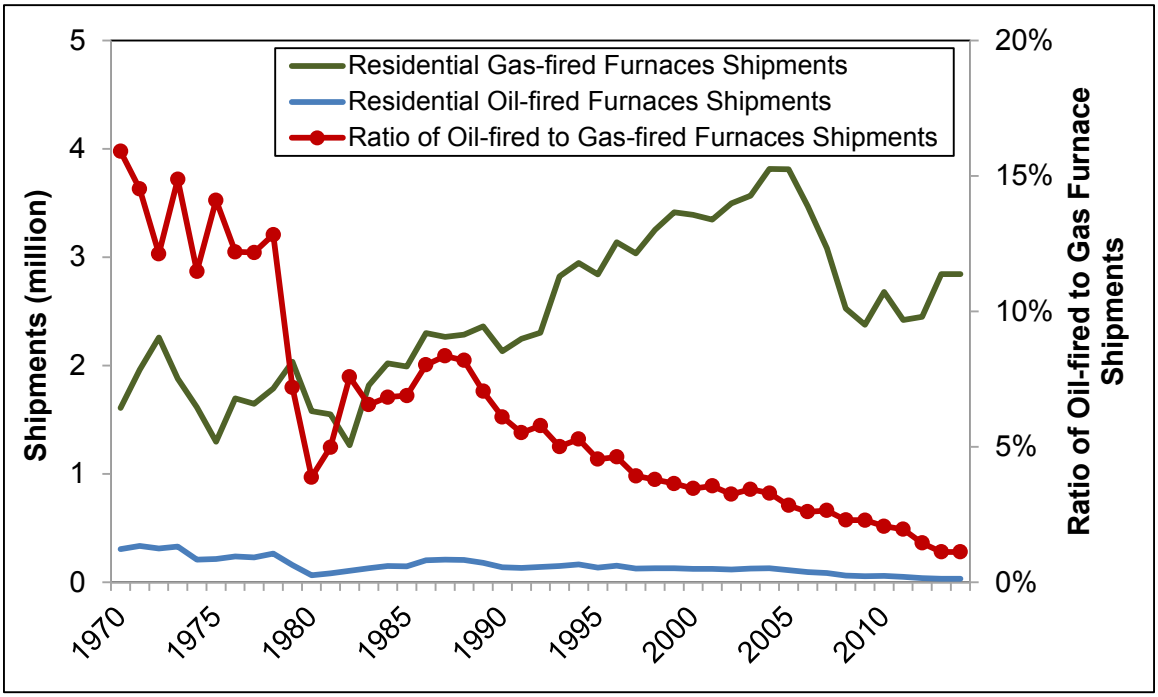

Figure 9.3.1 Ratio of Oil-fired to Gas Residential Furnaces, 1970-2014

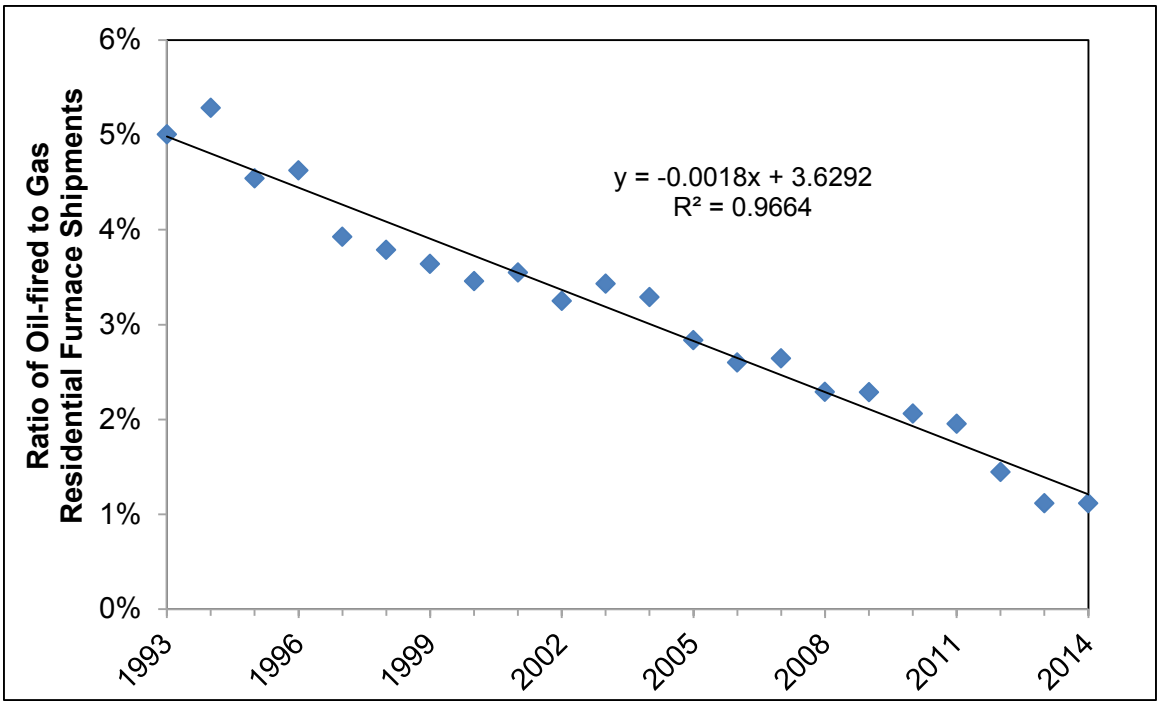

Figure 9.3.2 Ratio of Historical Shipments of Oil-fired vs. Gas-fired Residential Furnaces, 1993-2014

9.3.3 Survival Functions

The survival function represents the fraction of stock by age *a* that does not break or retire. Figure 9.3.3 shows the survival function for functioning stock and Figure 9.3.4 shows the survival function for extended repairs.

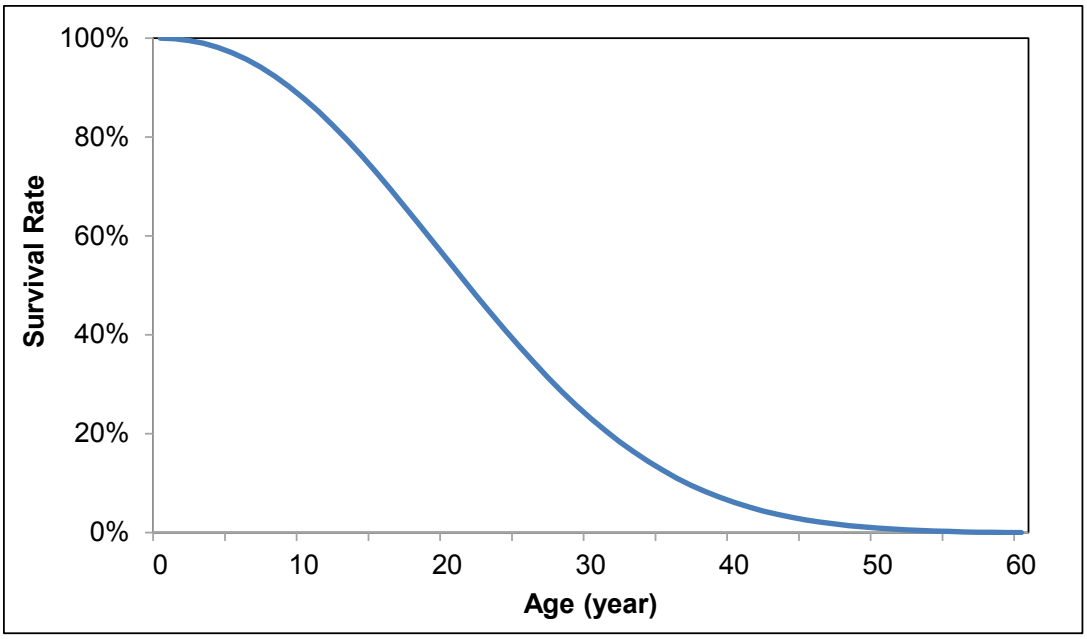

Figure 9.3.3 Survival Function for Functioning Stock

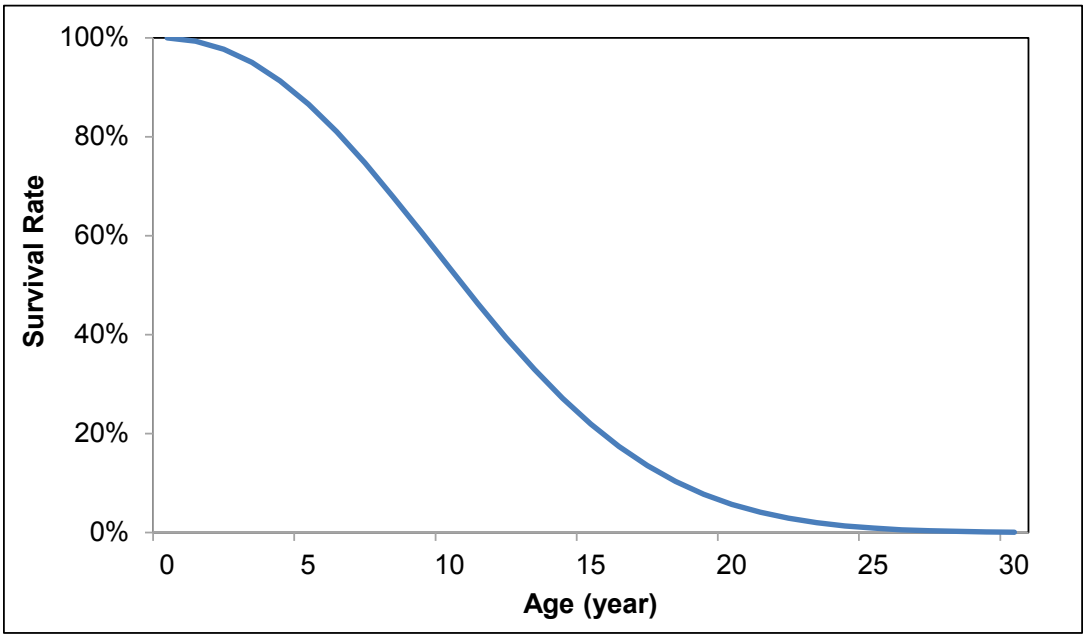

Figure 9.3.4 Survival Function for Extended Repairs

9.4 SHIPMENTS PROJECTIONS

DOE projected the shipments for CWAF based on the methodology described in section 9.2.5.

DOE estimated that the ratio of gas-fired CWAF shipments to CUAC shipments was 80 percent over the time, *i.e.*, $\theta_{CUAC}^{Gas}(y) = 0.8$, the ratio of gas-fired CWAF shipments to CUHP shipments was 20 percent over the time, *i.e.*, $\theta_{CUAC}^{Gas}(y) = 0.2$, and indoor gas-fired CWAF comprise 5 percent of the shipments over the time, *i.e.*, $\theta_{Indoor}^{Gas}(y) = 0.05$.

DOE assumed that the percentage of oil-fired CWAF shipments (1 percent of gas-fired CWAF shipments) would remain constant over the time period of 2015-2048.

For no-new-standards case, DOE projected the gas-fired CWAF shipments based on the Eq. 9.30, Eq. 9.31, Eq. 9.32, and Eq. 9.33 and the oil-fired CWAF shipments based on the equations Eq. 9.34, Eq. 9.35, Eq. 9.36, and Eq. 9.37.

For each standards case, DOE projected the gas-fired CWAF shipments based on the equations Eq. 9.38, Eq. 9.39, Eq. 9.40, and Eq. 9.41 and the oil-fired CWAF shipments based on the equations Eq. 9.42, Eq. 9.43, Eq. 9.44, and Eq. 9.45. For TSL 2 for CWAF standards, DOE accounted for the impact of the shipments of the Recommended TSL of CUAC and CUHP standards.

9.5 RESULTS

As detailed in chapter 10, DOE created trial standard levels (TSLs) that combine specific ELs across equipment classes. Table 9.5.1 shows the TSLs by EL for each equipment class DOE analyzed. Table 9.5.2 presents the TSLs by thermal efficiency (TE) for each equipment class DOE analyzed.

Table 9.5.1 Trial Standard Levels for Commercial Warm Air Furnaces by Efficiency Level

Equipment Class	TSL 1	TSL 2*	TSL 3	TSL 4	TSL 5
Gas-fired Commercial Warm Air Furnace	1	1	2	2	3
Oil-fired Commercial Warm Air Furnace	0	1	0	1	2

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 9.5.2 Trial Standard Levels for Commercial Warm Air Furnaces by Thermal Efficiency

Equipment Class	TSL 1	TSL 2*	TSL 3	TSL 4	TSL 5
Gas-fired Commercial Warm Air Furnace	81%	81%	82%	82%	92%
Oil-fired Commercial Warm Air Furnace	81%	82%	81%	82%	92%

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Figure 9.5.1 shows the resulting historical shipments for gas-fired and oil-fired CWAFs from 1970-2014. For gas-fired CWAF, Figure 9.5.2 shows the no-new-standards case shipments

projection for TSL 2 and the no-new-standards case shipments projection for the other TSLs, which differ due to the different CUAC/CUHP shipments projections that were used.

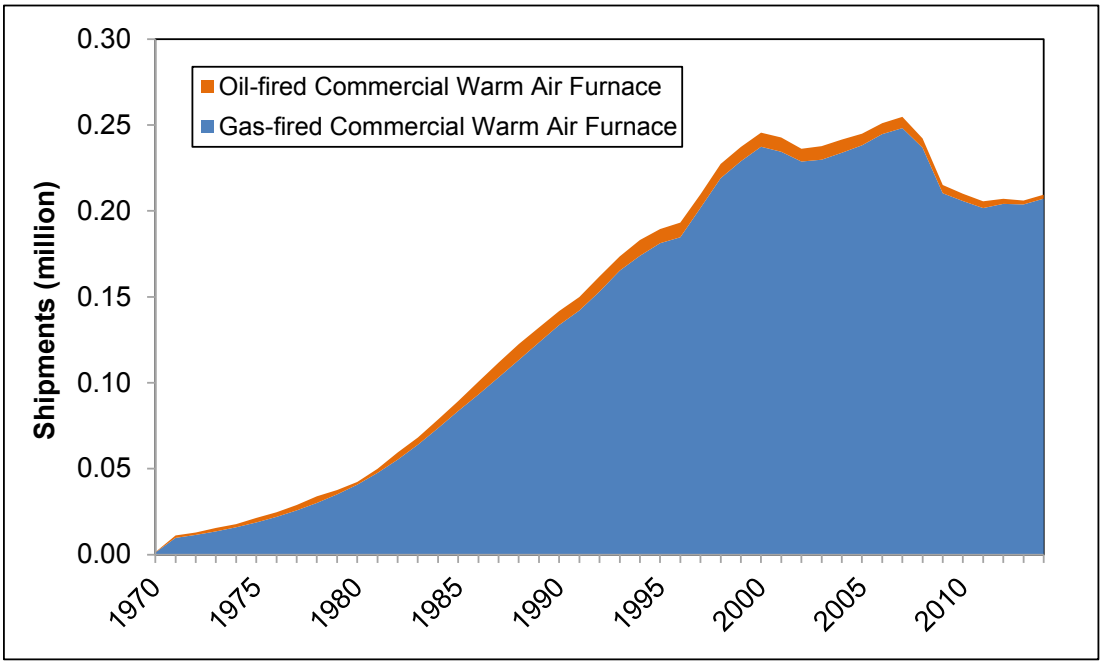

Figure 9.5.1 Historical Shipments of Commercial Warm Air Furnaces, 1970-2014

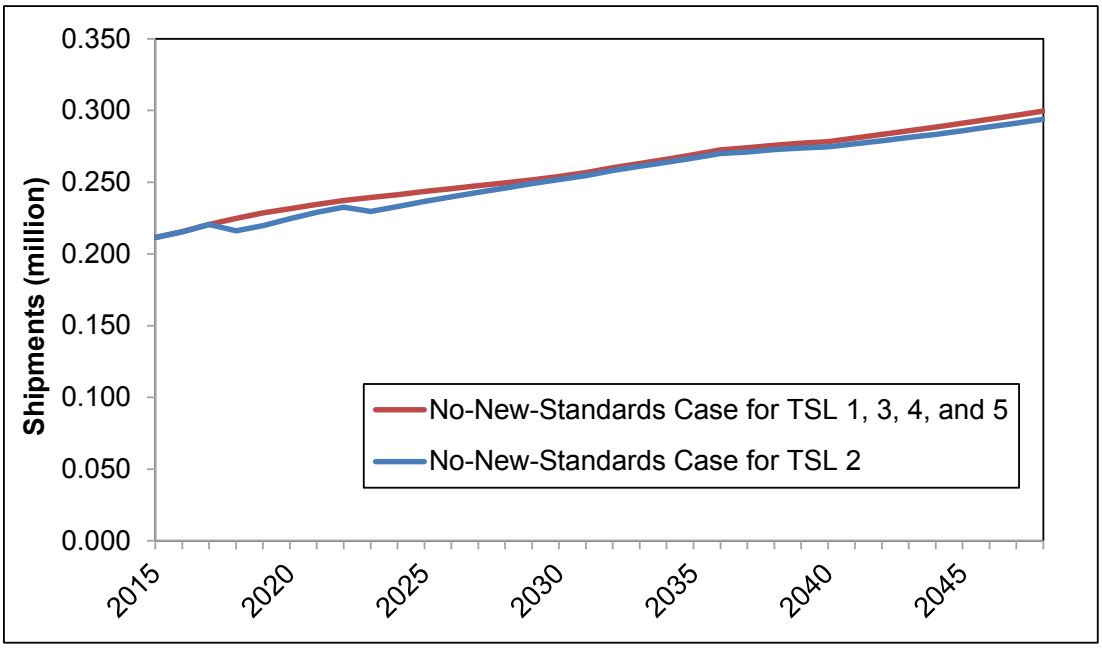

Figure 9.5.2 Projected Shipments in the No-New-Standards Case for TSLs 1, 3, 4, and 5 and the No-New-Standards Case for TSL 2

Figure 9.5.3 shows total projected shipments of gas-fired CWAF in the no-new-standards case and under each standards case. Because the elasticity is modeled as a delayed replacement of CWAF equipment, the projection for the TSLs shows a decline in the early years, but an increase in later years once the delayed replacements are finally made. As explained previously, the elasticity parameter decreases over time, so the impact of the standards on shipments diminishes. As previously shown in Figure 9.5.2, the no-new-standards case gas-fired CWAF shipments projection for TSL 2 is slightly different from the other TSLs (*i.e.*, TSL 1, 3, 4, and 5) to coordinate the CWAF standard with the CUAC/CUHP standard. As shown in Figure 9.5.3, the shipments projection for gas-fired CWAF for no-new-standards case used for TSL 2 is very close to the gas-fired CWAF shipments projection for TSL 2.

Figure 9.5.4 shows total shipment projections for oil-fired CWAF in the no-new-standards case and under each standards case. As with the gas-fired CWAF, the no-new-standards case oil-fired CWAF shipments projection for TSL 2 is very close to the TSL 2 oil-fired CWAF shipments projection.

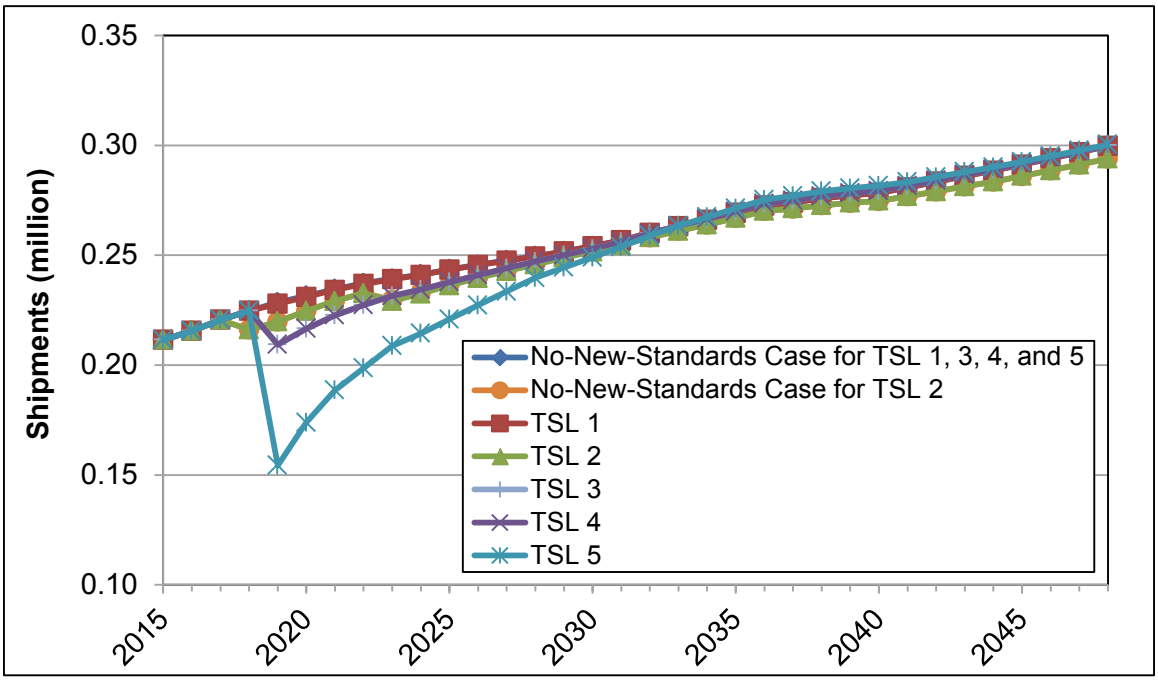

Figure 9.5.3 Projected Shipments of Gas-fired Commercial Warm Air Furnaces in the No-New-Standards Case and Each Standards Case, 2015-2048

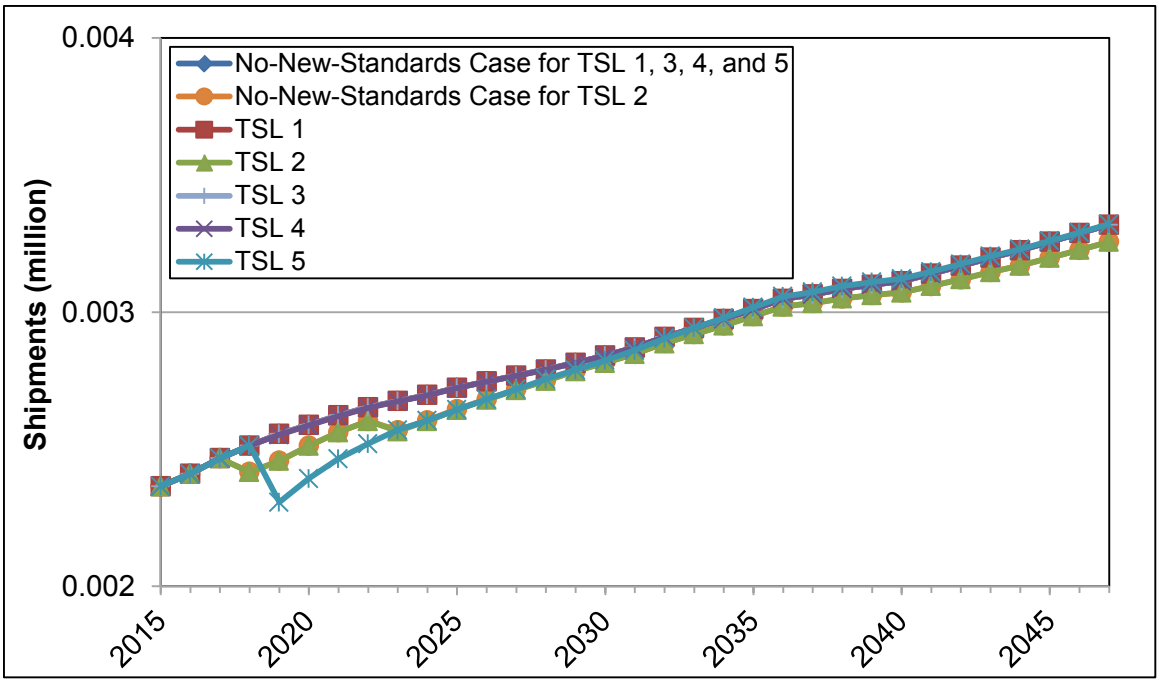

Figure 9.5.4 Projected Shipments of Oil-fired Commercial Warm Air Furnaces in the No-New-Standards Case and Each Standards Case, 2015-2048

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CHAPTER 10. NATIONAL IMPACT ANALYSES

TABLE OF CONTENTS

10.1 INTRODUCTION 10-1
10.2 TRIAL STANDARD LEVELS 10-2
10.3 PROJECTED EFFICIENCY TRENDS 10-2
10.3.1 No-New-Standards and Standards Case Efficiencies in the Compliance Year 10-2
10.3.2 Projected Efficiency Trends After 2019 10-3
10.4 NATIONAL ENERGY SAVINGS 10-5
10.4.1 Definition 10-5
10.4.2 Inputs to Calculation 10-6
10.4.2.1 Annual Energy Consumption per Unit 10-6
10.4.2.2 Shipments 10-7
10.4.2.3 Equipment Stock 10-8
10.4.2.4 National Annual Energy Consumption 10-8
10.4.2.5 Primary Energy Use Factor 10-8
10.4.2.1 Full-Fuel-Cycle Energy Factors 10-9
10.5 NET PRESENT VALUE OF CONSUMER BENEFITS 10-10
10.5.1 Definition 10-10
10.5.2 Inputs to Calculation 10-12
10.5.2.1 Total Installed Cost per Unit 10-12
10.5.2.2 Annual Operating Cost per Unit 10-13
10.5.2.3 Equipment Stock 10-14
10.5.2.4 Increases in Total Annual Installed Cost 10-14
10.5.2.5 Savings in Total Annual Operating Cost 10-15
10.5.2.6 Discount Factor 10-15
10.5.2.7 Present Value of Increased Installed Cost 10-15
10.5.2.8 Present Value of Savings 10-16
10.6 RESULTS 10-16
10.6.1 National Energy Savings 10-16
10.6.2 Net Present Value of Consumer Benefit 10-17

LIST OF TABLES

Table 10.2.1 Trial Standard Levels for Commercial Warm Air Furnaces 10-2
Table 10.3.1 Commercial Warm Air Furnaces: Efficiency Distributions for the No-New-Standards and Standards Cases in Compliance Year 10-3
Table 10.4.1 Average Annual Commercial Warm Air Furnace Energy Use for the No-New-Standards and Standards Cases in the Compliance Year 10-7
Table 10.4.2 Upstream Energy Multipliers (Based on *AEO 2015*) 10-10
Table 10.5.1 Average Installed Cost of Commercial Warm Air Furnaces in the Compliance Year for the No-New-Standards and Standards Cases (2014$) .. 10-13

Table 10.5.2 Average Annual Operating Cost of Commercial Warm Air Furnaces in the Compliance Year for the No-New-Standards and Standards Cases (2014$) .. 10-14
Table 10.6.1 Primary National Energy Savings for Commercial Warm Air Furnaces (quads)..... 10-16
Table 10.6.2 Full-Fuel-Cycle National Energy Savings for Commercial Warm Air Furnaces (quads) 10-16
Table 10.6.3 Net Present Value of Consumer Benefit for Commercial Warm Air Furnaces, Discounted at 3 Percent (billion 2014$)..... 10-17
Table 10.6.4 Net Present Value of Consumer Benefit for Commercial Warm Air Furnaces, Discounted at 7 Percent (billion 2014$)..... 10-17

LIST OF FIGURES

Figure 10.3.1 Projection of Efficiency Distribution for Gas-fired Commercial Warm Air Furnaces in the No-New-Standards Case, 2019-2048 10-4
Figure 10.3.2 Projection of Market Share for Condensing Gas-fired Commercial Warm Air Furnaces in the No-New-Standards Case, 2019-2048..... 10-4
Figure 10.4.1 Site-to-Power Plant Energy Use Factor for Commercial Warm Air Furnace Electricity, 2019-2040..... 10-9

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 commercial warm air furnaces (CWAF). 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 CWAF; (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/70). 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 two models used in the NIA—the NES model and the NPV model—are described more fully in subsequent sections. The descriptions include overviews of how DOE performed

[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.

each model's calculations and summaries of the major inputs. After the technical model descriptions, this chapter presents the results of the NIA calculations.

10.2 TRIAL STANDARD LEVELS

DOE analyzed the benefits and burdens of several TSLs for CWAF. TSLs are formed by grouping different efficiency levels (ELs), which are potential standard levels for each equipment class. Table 10.2.1 presents the five TSLs analyzed and the corresponding EL for each CWAF equipment class. TSL 5 represents the max-tech efficiency levels, which use condensing technology. For non-condensing efficiency levels, DOE considered all combinations of gas-fired and oil-fired CWAF efficiency levels as part of the TSL structure.

Table 10.2.1 Trial Standard Levels for Commercial Warm Air Furnaces

Equipment Class	TSL 1	TSL 2*	TSL 3	TSL 4	TSL 5
Efficiency Level					
Gas-fired Commercial Warm Air Furnace	1	1	2	2	3
Oil-fired Commercial Warm Air Furnace	0	1	0	1	2
Thermal Efficiency (TE)					
Gas-fired Commercial Warm Air Furnace	81%	81%	82%	82%	92%
Oil-fired Commercial Warm Air Furnace	81%	82%	81%	82%	92%

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

10.3 PROJECTED EFFICIENCY TRENDS

A key component of the NIA is the energy efficiency projected over time for the no-new-standards case and for each of the standards cases. The projected energy efficiency is used to determine the average shipment-weighted values used to calculate the NES and NPV, such as annual energy consumption, total installed costs, and operating costs.

10.3.1 No-New-Standards and Standards Case Efficiencies in the Compliance Year

For each CWAF equipment class, DOE developed a distribution of efficiencies in the no-new-standards case in the assumed compliance year for amended standards,[b] as described in chapter 8. In each standards case, DOE assumed a "roll-up" scenario to establish the efficiency distribution for 2023 for TSL 2 and 2019 for other TSLs. Equipment efficiencies in the no-new-standards case that do 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 are above the standard

[b] According to the terms of the negotiated rulemaking, for TSL 2, the compliance year is 2023. For the other TSLs, the compliance year is 2019.

under consideration would not be affected. Table 10.3.1 presents the efficiency distributions for the no-new-standards case and standards cases for gas-fired and oil-fired CWAF.

Table 10.3.1 Commercial Warm Air Furnaces: Efficiency Distributions for the No-New-Standards and Standards Cases in Compliance Year

Efficiency Level		Market Share (percent)					
		No-New-Standards Case	Trial Standard Level (TSL)				
			1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace							
0	80% Baseline	71.5					
1	81%	27.1	98.6	98.1			
2	82%	0.2	0.2	0.2	98.9	98.9	
3	92% Max Tech	1.1	1.1	1.7	1.1	1.1	100.0
Oil-fired Commercial Warm Air Furnace							
0	81% Baseline	39.9	39.9		39.9		
1	82%	60.1	60.1	100.0	60.1	100.0	
2	92% Max Tech	0.0	0.0	0.0	0.0	0.0	100.0

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

10.3.2 Projected Efficiency Trends After 2019

In the absence of amended standards (no-new-standards case), DOE estimated that there would be some growth in the overall market share of condensing gas-fired CWAF, from 1 percent in 2019 to 5 percent in 2048. Figure 10.3.1 shows the shares of each gas-fired CWAF efficiency level from 2019–2048. The shares of the non-condensing ELs (ELs 0 through 2) are kept in the same proportional relationship as in 2019, but the overall non-condensing market share decreases as the condensing gas-fired CWAF market share increases. For oil-fired CWAF, DOE kept the shares of all the ELs the same as in 2019 during the analysis period and assumed that there would not be any condensing oil-fired CWAF shipments. Figure 10.3.2 shows the no-new-standards case market share of gas-fired condensing CWAF from 2019–2048.

The difference between these standards cases and the no-new-standards case is in the market shares of the various non-condensing CWAF 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 CWAF designs decrease as the condensing gas-fired CWAF market share increases over time.

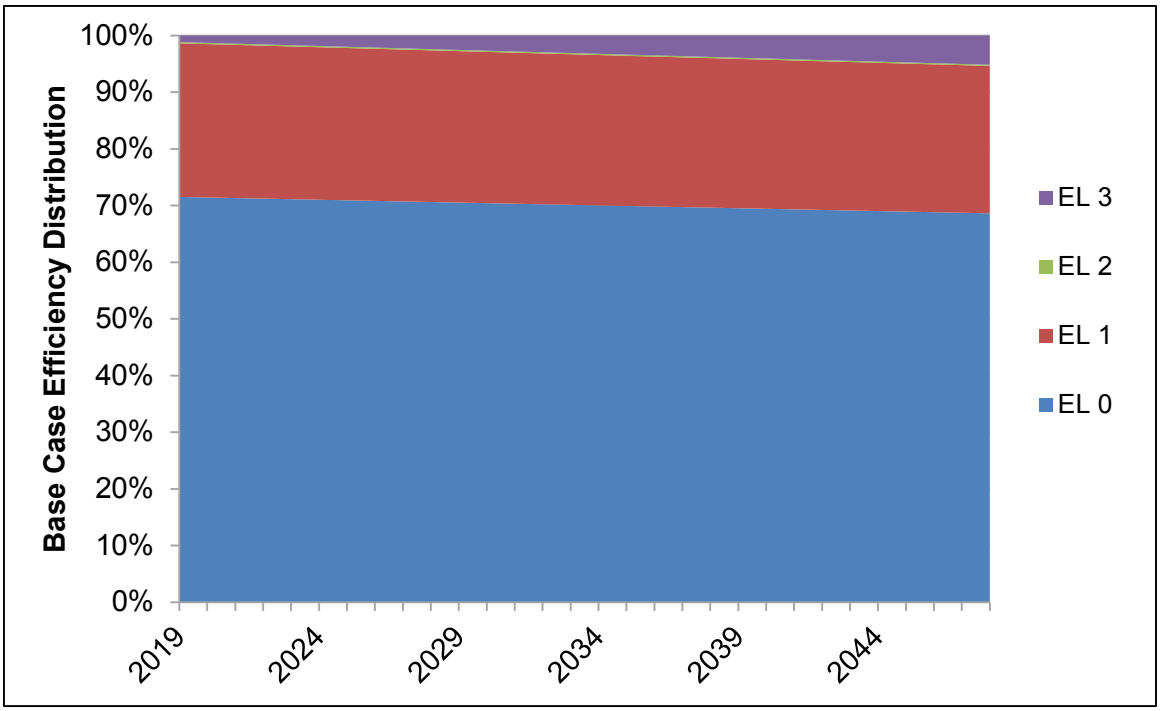

Figure 10.3.1 Projection of Efficiency Distribution for Gas-fired Commercial Warm Air Furnaces in the No-New-Standards Case, 2019-2048

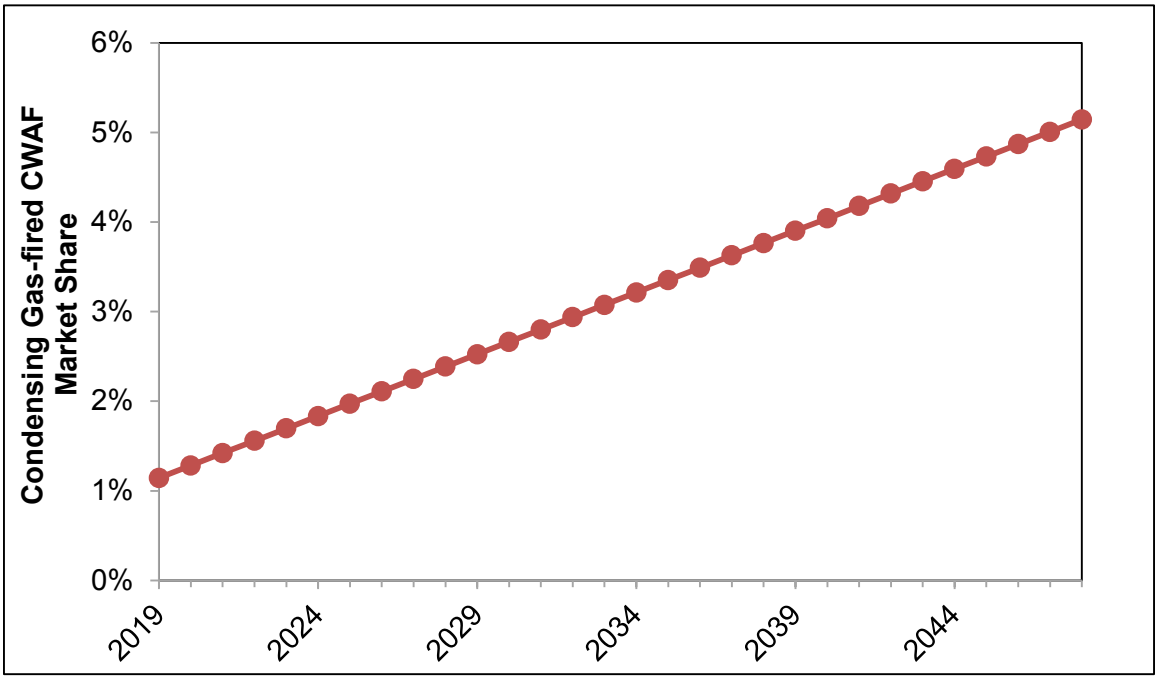

Figure 10.3.2 Projection of Market Share for Condensing Gas-fired Commercial Warm Air Furnaces in the No-New-Standards Case, 2019-2048

10.4 NATIONAL ENERGY SAVINGS

This section describes DOE's calculation of NES for CWAF under the considered TSLs.

10.4.1 Definition

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 equipment shipped in the analysis period.[c] 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 equipment of vintage V that survive in the year for which DOE calculated annual energy consumption,
UEC_V = annual energy consumption per unit of equipment 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

[c] For TSL 2, the analysis period is from the compliance date of the standard (2023) through 2048. For the other TSLs, the analysis period is from the compliance date of the standard (2019) through 2048.

V = year in which the equipment was purchased as a new unit.

The stock of equipment depends in part on annual shipments projections from chapter 9 for the no-new-standards case and each standards case. Based on the building sample in the life-cycle cost (LCC) and payback period (PBP) analysis, DOE estimated that a fraction of CWAF (2.1 percent) are shipped to residential buildings. The national energy savings from CWAF in the standards cases include the savings from both commercial and residential users of CWAF.

10.4.2 Inputs to Calculation

The inputs for calculating national energy savings are:

- average annual energy consumption per unit (*UEC*),
- shipments,
- equipment 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 equipment class, DOE developed the per-unit annual energy consumption as a function of equipment 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 10.3, along with the annual energy use data presented in chapters 7 and 8, to estimate the shipments-weighted average annual per-unit energy consumption (UEC) under the no-new-standards and standards cases.

Table 10.4.1 presents the no-new-standards case and standards case shipments-weighted UEC for gas-fired and oil-fired CWAF in the compliance year of amended standards. The values are a weighted average for commercial and residential CWAF commercial consumers.

Table 10.4.1 Average Annual Commercial Warm Air Furnace Energy Use for the No-New-Standards and Standards Cases in the Compliance Year

Equipment Class	No-New-Standards Case	Trial Standard Levels				
		1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace						
Average Annual Fuel Use (MMBtu/yr)	159.4	158.0	156.4	156.2	156.2	139.6
Average Annual Elec Use (kWh/yr)	836.7	830.2	823.3	821.5	821.5	1044.5
Oil-fired Commercial Warm Air Furnace						
Average Annual Fuel Use (MMBtu/yr)	117.4	117.4	115.6	117.4	117.0	106.6
Average Annual Elec Use (kWh/yr)	694.7	694.7	685.6	694.7	692.3	931.5

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

The annual energy use after the compliance date change according to the projected efficiency trends in each case. DOE also considered the effects of changes in climate and building shell efficiency on projected CWAF energy use. The climate adjustment factor is based on the forecast of heating degree days (HDD) from the Energy Information Administration (EIA)'s *Annual Energy Outlook 2015* (*AEO 2015*), which shows a declining trend due to warmer weather.[1] The building shell efficiency factor is also from *AEO 2015.* For both factors, DOE applied regional weights to make the factors specific to commercial and residential commercial consumers of gas and oil-fired CWAF. Due to these adjustment factors, the shipment-weighted energy use decreases by 7 percent during the analysis period.

10.4.2.2 Shipments

DOE projected shipments for each equipment 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, commercial consumer income, and equipment lifetime. As noted previously, the increased total installed cost of more-efficient equipment causes some commercial consumers to forego equipment purchases. Consequently, shipments projected under the standards cases are lower than under the no-new-standards case. The method DOE used to calculate and generate the shipments projections for each considered product class is described in detail in chapter 9, Shipments Analysis.

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 standards cases 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 Equipment Stock

The stock of equipment in any given year depends on annual shipments and the lifetime of a given equipment 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 assumed that CWAF 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 National Annual Energy Consumption

National annual energy consumption is the product of the annual energy consumption per unit and the number of units of each vintage. This calculation accounts for differences in unit energy consumption from year to year. The equation for determining AEC, presented in section 10.4.1, is repeated here.

$$AEC = \sum STOCK_V \times UEC_V$$

In determining national annual energy consumption, DOE initially calculates annual energy consumption at the site and then applies a conversion factor to calculate primary energy consumption.

10.4.2.5 Primary Energy Use Factor

DOE calculated primary energy savings (power plant consumption) from site energy savings by applying a factor to account for losses associated with the generation, transmission, and distribution of electricity. For electricity use, the conversion from site kWh to power plant primary million Btu uses a marginal heat rate factor that accounts for losses associated with the generation, transmission, and distribution of electricity. DOE derived these marginal factors using data published with *AEO 2015*, following the methodology outlined in appendix 15A. The factors depend on the sector and end-use, and also vary with time due to changes in the mix of fuels used for electric power generation. Figure 10.4.1 shows the site-to-power plant factors from 2019 to 2040. For years after 2040 (the last year in *AEO 2015*), DOE held the factors constant and equal to their 2040 values.

For fossil fuels such as natural gas, fuel oil or propane, the site energy and primary energy are the same, as energy used in processing is captured in the FFC metric.

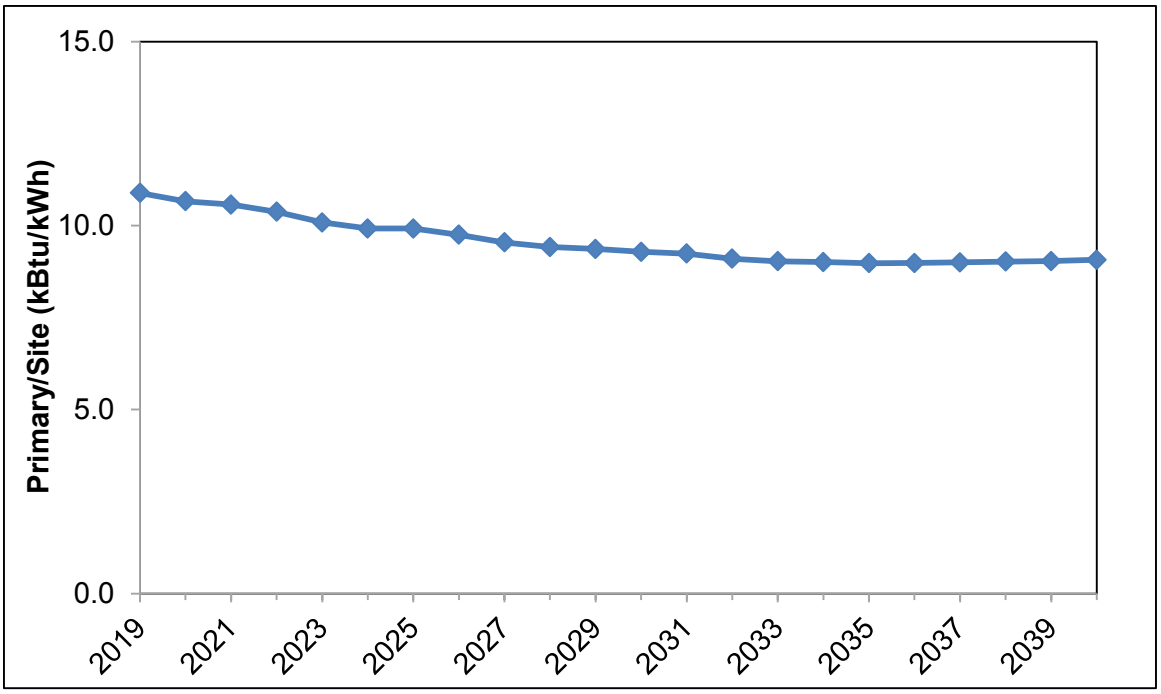

Figure 10.4.1 Site-to-Power Plant Energy Use Factor for Commercial Warm Air Furnace Electricity, 2019-2040

10.4.2.1 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 full-fuel-cycle metric by calculating the difference relative to the no-new-standards case and summing over the analysis period:

$$NES - FFC(L,y) = FFC(L=0,y) - FFC(L,y),$$

$$NES - FFC_{cum}(L) = \sum_y NES - FFC(L,y)$$

Appendix 10B describes the method used to calculate FFC energy multipliers.

Table 10.4.2 shows the upstream energy multipliers used for CWAF for selected years. For years after 2040 (the last year in the *AEO*), DOE maintained the 2040 value.

Table 10.4.2 Upstream Energy Multipliers (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

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. 10.5

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. 10.6

$$PVC = \sum TIC_y \times DF_y$$

Eq. 10.7

Where:

OCS_y = total annual savings in operating cost each year summed over vintages of the equipment stock in each year *y*,
TIC_y = total annual increase in installed cost each year summed over vintages of the equipment 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 unit of equipment (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 unit of equipment (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:

$$OCS_y = \sum STOCK_V \times UOCS_V$$

$$TIC_y = \sum STOCK_V \times UTIC_V$$

Eq. 10.8

Where:

$STOCK_V$ = stock of equipment of vintage *V* that survive in year *y* in the projection,
$UOCS_V$ = annual per-unit savings in operating cost of equipment of vintage *V*,
$UTIC_V$ = annual total per-unit increase in installed cost of equipment of vintage *V*, and
V = year in which the equipment purchased as a new unit.

As mentioned in section 10.4.1, DOE estimated that a fraction of CWAF (2.1 percent) are shipped to residential buildings. The net present value of consumer benefits in the standards cases includes the benefits from both commercial and residential CWAF users.

For TSL 2, DOE determined the *PVC* for each year from the compliance date of the standard (2023) through 2048. For the other TSLs, DOE determined the *PVC* for each year from the compliance date of the standard (2019) through 2048. DOE determined the *PVS* for each year from the applicable compliance date of the standard until the year when units purchased in the applicable analysis period 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,
- equipment 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 EL. As with calculating energy savings, DOE did not use no-new-standards-case shipments to calculate total annual installed costs for all of the equipment classes. Instead, DOE used the projected shipments and stock for each EL 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 EL. 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 equipment class as a function of equipment 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 CWAF in the compliance year for the no-new-standards case and standards cases for the two equipment classes considered.

Table 10.5.1 Average Installed Cost of Commercial Warm Air Furnaces in the Compliance Year for the No-New-Standards and Standards Cases (2014$)

Equipment Class	No-New-Standards Case	Trial Standard Levels				
		1	2*	3	4	5
Gas-fired CWAF	$2,066	$2,086	$2,018	$2,508	$2,508	$3,773
Oil-fired CWAF	$6,305	$6,305	$6,093	$6,305	$6,326	$7,765

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

DOE developed the default product price trend based on an exponential fit function derived using historical data on warm air furnaces Producer Price Index (PPI) (described in chapter 8) to project the future equipment price of CWAF sold in each year throughout the analysis period. The average estimated annual price decline rate in the default case is 0.93 percent. To investigate the impact of different equipment price projections on the consumer NPV for different standard 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.

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 equipment class by the appropriate energy price. DOE considered operating costs separately for commercial and residential users of CWAF.

Estimates of the per-unit annual energy consumption for the no-new-standards case and each standards case were presented in section 10.4.2.1. DOE projected the per-unit annual energy consumption for the no-new-standards case for all equipment 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 commercial and residential energy prices in EIA's *AEO 2015* reference case scenario.[d]

[d] The reference case is a business-as-usual estimate, given known market, demographic, and technological trends. DOE conducted sensitivity analyses using alternative economic growth scenario assumptions (see appendix 10D).

DOE described the total per-unit repair and maintenance costs for each equipment class as a function of equipment 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 10.5.2 shows the average operating cost of CWAF in the compliance year for the no-new-standards case and standards cases for the two equipment classes considered. The operating costs change over time, depending on changes in annual energy use and energy prices.

Table 10.5.2 Average Annual Operating Cost of Commercial Warm Air Furnaces in the Compliance Year for the No-New-Standards and Standards Cases (2014$)

Equipment Class	No-New-Standards Case	Trial Standard Levels				
		1	2*	3	4	5
Gas-fired CWAF	$1,705	$1,691	$1,857	$1,674	$1,674	$1,556
Oil-fired CWAF	$3,011	$3,011	$3,179	$3,011	$3,000	$2,824

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

10.5.2.3 Equipment Stock

The stock of equipment in any given year depends on annual shipments and the lifetime of a given equipment 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 the specific section for each equipment class in chapter 9 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 equipment 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. The equation for determining the total annual installed cost increase for a given TSL, which was presented in section 10.5.1, is repeated here:

$$TIC = \sum STOCK_V \times UTIC_V$$

10.5.2.5 Savings in Total Annual Operating Cost

The savings in total annual operating cost for any given TSL 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. The equation for determining the total annual savings in operating cost for a given TSL, which was presented in section 10.5.1, is repeated here.

$$OCS = \sum STOCK_V \times UOCS_V$$

As discussed in chapter 8, DOE did not apply a rebound effect to adjust its estimates of energy savings because it is unlikely that commercial consumers will use a higher-efficiency CWAF more than a baseline one.

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. 10.9

Where:

r = discount rate,
y = year of the monetary value, and
y_p = year in which the present value is being determined.

Although DOE used consumer discount rates to determine the life-cycle cost of CWAF (chapter 8), it used national discount rates to calculate national NPV. 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.[2] DOE defined the present year as 2015.

10.5.2.7 Present Value of Increased Installed Cost

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 through 2048). DOE calculated annual increases in installed cost as the difference in total installed cost for new equipment purchased each year, multiplied by the shipments in the standards case.

10.5.2.8 Present Value of Savings

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 to the time when the last unit installed during the analysis period is retired from service.

Savings represent decreases in operating cost (including electricity, repair, and maintenance) associated with the more-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 commercial warm air furnaces. See Table 10.6.1 for primary energy savings and Table 10.6.2 for full-fuel cycle 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 LCC and PBP analysis.

Table 10.6.1 Primary National Energy Savings for Commercial Warm Air Furnaces (quads)

Equipment Class	Trial Standard Levels*				
	1	2	3	4	5
Gas-fired Commercial Warm Air Furnace	0.221	0.204	0.362	0.362	2.065
Oil-fired Commercial Warm Air Furnace	0.000	0.001	0.000	0.001	0.014
Total	0.221	0.204	0.362	0.363	2.079

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10.6.2 Full-Fuel-Cycle National Energy Savings for Commercial Warm Air Furnaces (quads)

Equipment Class	Trial Standard Levels*				
	1	2	3	4	5
Gas-fired Commercial Warm Air Furnace	0.247	0.228	0.405	0.405	2.343
Oil-fired Commercial Warm Air Furnace	0.000	0.001	0.000	0.001	0.016
Total	0.247	0.229	0.405	0.406	2.359

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

10.6.2 Net Present Value of Consumer Benefit

This section provides results of calculating the NPV for each TSL considered for CWAF. Results were calculated for the nation as a whole. Results, which are cumulative, are shown as the discounted dollar value of the net savings. See Table 10.6.3 for 3-percent discount rate and Table 10.6.4 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 is produced by the LCC and PBP analysis.

Table 10.6.3 Net Present Value of Consumer Benefit for Commercial Warm Air Furnaces, Discounted at 3 Percent (billion 2014$)

Equipment Class	Trial Standard Levels*				
	1	2	3	4	5
Gas-fired Commercial Warm Air Furnace	1.066	0.964	-0.061	-0.061	2.463
Oil-fired Commercial Warm Air Furnace	0.000	0.010	0.000	0.011	0.141
Total	1.066	0.974	-0.061	-0.050	2.605

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10.6.4 Net Present Value of Consumer Benefit for Commercial Warm Air Furnaces, Discounted at 7 Percent (billion 2014$)

Equipment Class	Trial Standard Levels*				
	1	2	3	4	5
Gas-fired Commercial Warm Air Furnace	0.386	0.326	-0.360	-0.360	-0.402
Oil-fired Commercial Warm Air Furnace	0.000	0.003	0.000	0.004	0.036
Total	0.386	0.329	-0.360	-0.356	-0.366

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

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APPENDIX 10A. USER INSTRUCTIONS FOR NATIONAL IMPACT ANALYSES SPREADSHEET MODEL

TABLE OF CONTENTS

10A.1 USER INSTRUCTIONS 10A-1
10A.2 STARTUP 10A-1
10A.3 DESCRIPTION OF NATIONAL IMPACT ANALYSIS WORKSHEETS 10A-1
10A.4 BASIC INSTRUCTIONS FOR OPERATING THE NATIONAL IMPACT ANALYSIS SPREADSHEETS 10A-2

LIST OF FIGURES

Figure 10A.4.1 Default User Input Parameters (Summary) 10A-3
Figure 10A.4.2 NIA Results Summary 10A-4
Figure 10A.4.3 Setting the Spreadsheet to Automatic Calculation Mode 10A-4

APPENDIX 10A. USER INSTRUCTIONS FOR NATIONAL IMPACT ANALYSES 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) commercial warm air furnace (CWAF) rulemaking page: www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/70. From that page, follow the links to the direct final rule phase of the rulemaking and then to the analytical tools.

10A.2 STARTUP

The National Impact Analysis (NIA) spreadsheets enable the user to perform an NIA for CWAF. 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® 2007 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 amended 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 CWAFs shipped under that standard. The differences between the standards and no-new-standards 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).
Gas CWAF	Contains gas-fired CWAF NIA calculations.
Oil CWAF	Contains oil-fired CWAF NIA calculations.
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.
Historical Shipments	Contains historical shipments data for each equipment type.
Price Index	Contains the learning multipliers to adjust the manufacturer's cost over the entire analysis period.
Energy Index	Contains the energy use trend multipliers to adjust for the climate conditions during the analysis period.
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.
Supplementary Worksheets	Worksheets used for displaying outputs for documentation and downstream analyses.

10A.4 BASIC INSTRUCTIONS FOR OPERATING THE NATIONAL IMPACT ANALYSIS SPREADSHEETS

Basic instructions for operating the NIA spreadsheets are as follows:

1. Once the NIA spreadsheet file has been downloaded from the Department's web site, 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	3%
Analysis Period	Full
Energy Savings	Primary
Replace/Repair	Repair
Price Trend	Reference
Energy Trend	Decr HDD
Price Elast	Yes

TSL	1
Compliance Year	2019
Number of Years	30

Figure 10A.4.1 **Default User Input Parameters (Summary)**

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 "Primary". 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) 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").

f) Price Trend: Set to "Reference". To change value, click on the drop down menu next to cell "Price Trend" and change to desired scenario ("Reference", "High", or "Low").

g) 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").

h) Price Elasticity: Set to "Yes". To change value, click on the drop down menu next to cell "Price Elast" and change to desired scenario ("Yes" or "No").

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").

j) Compliance Year: 2023 for TSL 2; 2019 for all other TSLs.

k) Number of Years: 26 years for TSL 2; 30 years for all other TSLs.

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		Gas CWAF	Oil CWAF	Total
NPV	mi 2014$	1065.9	0.00000	1065.9
Incr Equipment Costs	mi 2014$	79.5	0.00000	79.5
Operating Cost Savings	mi 2014$	1145.4	0.00000	1145.4
Primary Energy Savings	quads	0.221	0.00000	0.221
Electricity	quads	0.009	0.00000	0.009
Natural Gas	quads	0.212		0.212
Fuel Oil	quads		0.00000	0.000
Perc of BC Consumption	%	0.8%	0.0%	0.8%

Figure 10A.4.2 **NIA Results Summary**

Note: Make sure that the spreadsheet is in automatic calculation mode. The calculation mode could be changed by (shown in Figure 10A.4.3):

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 equipment class.

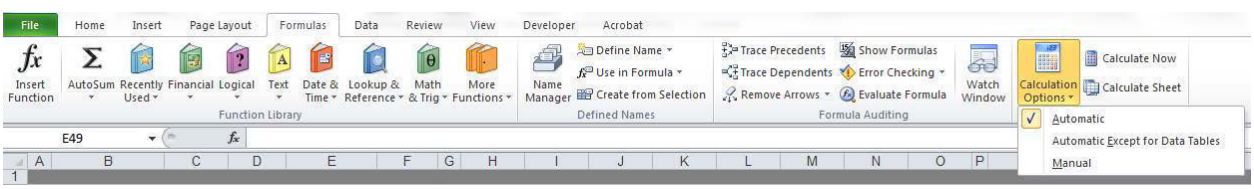

Figure 10A.4.3 **Setting the Spreadsheet to Automatic Calculation Mode**

APPENDIX 10B. FULL-FUEL-CYCLE ANALYSIS

TABLE OF CONTENTS

10B.1 INTRODUCTION 10B-1
10B.2 MARGINAL HEAT RATES.....10B-2
10B.3 FFC METHODOLOGY 10B-4
10B.4 ENERGY MULTIPLIERS FOR THE FULL FUEL CYCLE.....10B-6

LIST OF TABLES

Table 10B.2.1 Marginal Heat Rates (quads/TWh) by Sector and End-Use 10B-4
Table 10B.3.1 Dependence of FFC Parameters on *AEO* Inputs.....10B-5
Table 10B.4.1 Energy Multipliers for the Full Fuel Cycle (Based on *AEO 2015*).....10B-6

LIST OF FIGURES

Figure 10B.2.1 Fuel Specific Marginal (Solid) and Average (Dashed) Heat Rates 10B-3

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.

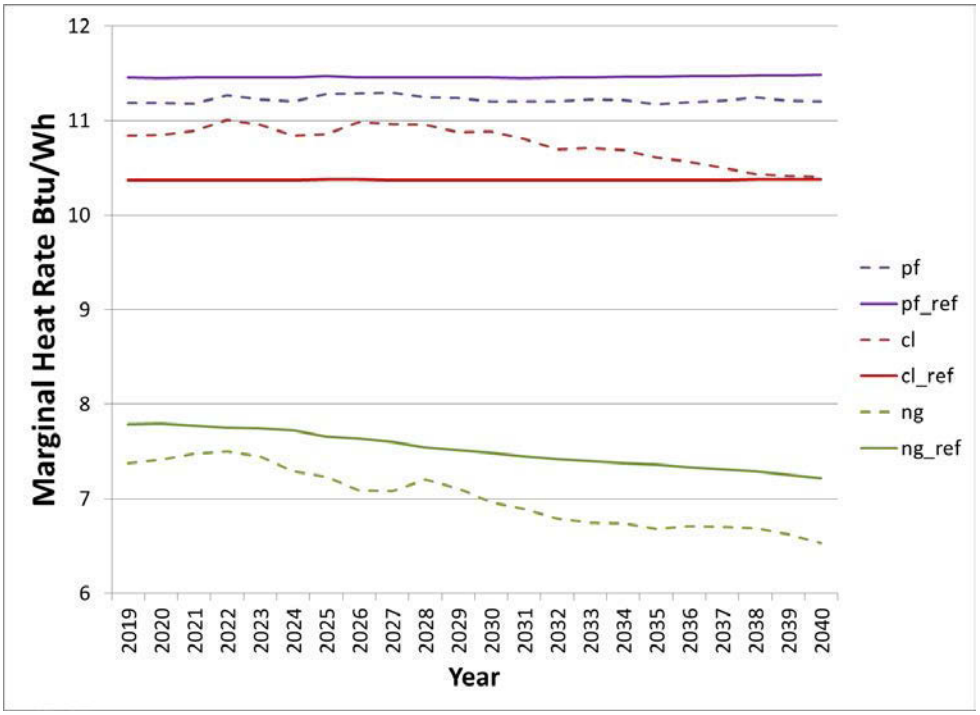

Figure 10B.2.1 Fuel Specific Marginal (Solid) and Average (Dashed) Heat Rates

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*)

	2019	2020	2025	2030	2035	2040
Electricity	1.044	1.044	1.045	1.046	1.045	1.045
Natural gas	1.119	1.123	1.124	1.123	1.122	1.123
Petroleum fuels	1.171	1.171	1.169	1.165	1.165	1.165

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APPENDIX 10C. NATIONAL NET PRESENT VALUE OF COMMERCIAL WARM AIR FURNACES USING ALTERNATIVE EQUIPMENT PRICE FORECASTS

TABLE OF CONTENTS

10C.1 INTRODUCTION 10C-1
10C.2 ALTERNATIVE COMMERCIAL WARM AIR FURNACE PRICE TREND SCENARIOS 10C-1
10C.2.1 Annual Energy Outlook 2015 Price Forecast – Low Price Decline 10C-1
10C.2.2 Exponential Fit Approach – High Price Decline 10C-1
10C.2.3 Summary 10C-3
10C.3 NET PRESENT VALUE RESULTS USING ALTERNATIVE EQUIPMENT PRICE TRENDS 10C-4

LIST OF TABLES

Table 10C.2.1 Price Trend Sensitivities 10C-3
Table 10C.3.1 NPV Using Reference Equipment Price Forecast, Discounted at 3 Percent, for Commercial Warm Air Furnaces (Billion 2014$) 10C-4
Table 10C.3.2 NPV Using Reference Equipment Price Forecast, Discounted at 7 Percent, for Commercial Warm Air Furnaces (Billion 2014$) 10C-5
Table 10C.3.3 NPV Using Alternative Equipment Price Forecast (High Price Decline Trend), Discounted at 3 Percent, for Commercial Warm Air Furnaces (Billion 2014$) 10C-5
Table 10C.3.4 NPV Using Alternative Equipment Price Forecast (High Price Decline Trend), Discounted at 7 Percent, for Commercial Warm Air Furnaces (Billion 2014$) 10C-5
Table 10C.3.5 NPV Using Alternative Equipment Price Forecast (Low Price Decline Trend), Discounted at 3 Percent, for Commercial Warm Air Furnaces (Billion 2014$) 10C-5
Table 10C.3.6 NPV Using Alternative Equipment Price Forecast (Low Price Decline Trend), Discounted at 7 Percent, for Commercial Warm Air Furnaces (Billion 2014$) 10C-6
Table 10C.3.7 Comparison of Total NPV Across All Equipment Classes for Alternative Equipment Price Forecast (Billion 2014$) 10C-6

LIST OF FIGURES

Figure 10C.2.1 Nominal and Deflated Warm Air Furnaces PPI from 1989 to 2006 ..... 10C-2
Figure 10C.2.2 Deflated Warm Air Furnaces PPI versus Year, with Exponential Fit from 1989 to 2006 ..... 10C-3
Figure 10C.2.3 Commercial Warm Air Furnaces Price Forecast Indexes 10C-4

APPENDIX 10C. NATIONAL NET PRESENT VALUE OF COMMERCIAL WARM AIR FURNACES USING ALTERNATIVE EQUIPMENT PRICE FORECASTS

10C.1 INTRODUCTION

The NPV results presented in chapter 10 are based on a future price projection derived from historical Producer Price Index (PPI) data from the Bureau of Labor Statistics (BLS). DOE collected PPI data of "warm air furnaces" from 1989 to 2014 to project future prices of commercial warm air furnaces (CWAFs). DOE also investigated the impact of different equipment price forecasts on the consumer net present value (NPV) for the considered TSLs of both gas-fired and oil-fired CWAFs. DOE considered two price sensitivity scenarios: (1) a trend based on the exponential fit using the same PPI data from 1989 to 2006, and (2) a trend based on "industrial equipment" that was forecasted in the Energy Information Administration's (EIA) *Annual Energy Outlook 2015* (*AEO 2015*).[1]

10C.2 ALTERNATIVE COMMERCIAL WARM AIR FURNACE PRICE TREND SCENARIOS

DOE considered two alternative price trends for a sensitivity analysis. One that assumes a low price decline scenario using the "Chained Price Index – industrial equipment" index forecasted for *AEO 2015*. The other assumes a high price decline scenario based on an exponential fit on the deflated producer price index for warm air furnaces from 1989 to 2006.[a]

10C.2.1 Annual Energy Outlook 2015 Price Forecast – Low Price Decline

For the low price decline scenario, DOE examined a forecast based on the "Chained price index—industrial equipment" index that was forecasted for *AEO 2015* from 2014 to 2040. This index is the most disaggregated index that includes CWAFs. To develop an inflation-adjusted index, DOE deflated the aforementioned index with the "chained price index—gross domestic product" forecasted for *AEO 2015*. To extend the price index beyond 2040, DOE used the average annual growth rate from 2031 to 2040.

10C.2.2 Exponential Fit Approach – High Price Decline

For the high price decline scenario, DOE used an inflation-adjusted warm air furnaces PPI spanning the time period of 1989-2006 from the Bureau of Labor Statistics' (BLS) to fit an exponential model with *year* as the explanatory variable. The PPI shows a steeper downward trend during this period of time, so the exponential fit represents the high price decline scenario of future price projection for CWAFs. The PPI data reflect nominal prices, adjusted for equipment quality changes. An inflation-adjusted (deflated) price index for warm air furnaces was calculated by dividing the PPI series by the Gross Domestic Product Chained Price Index.

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[a] PCU PCU333415333415C: Warm air furnaces including duct furnaces, humidifiers and electric comfort heating. Available at: www.bls.gov/ppi/

The deflated price index is presented in 2014 dollar values. Both the nominal and deflated price indexes for heating equipment manufacturing are presented below in Figure 10C.2.1.

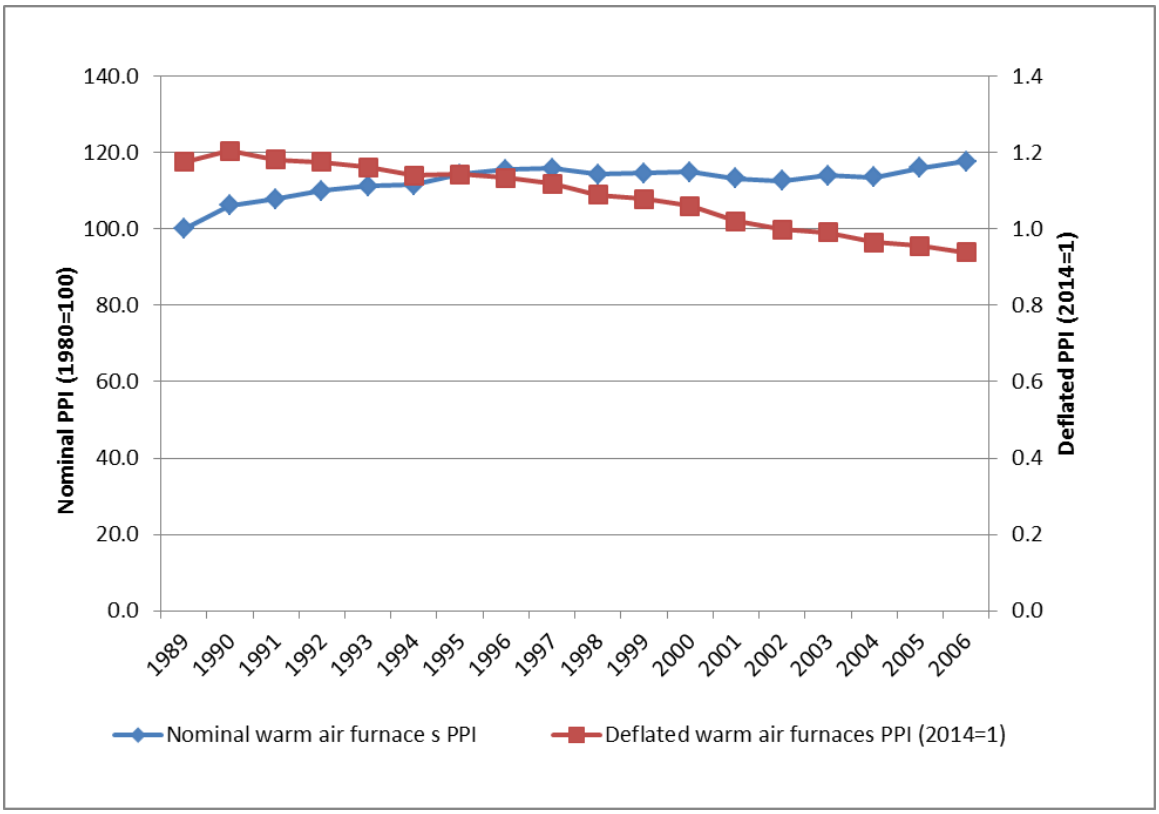

Figure 10C.2.1 Nominal and Deflated Warm Air Furnaces PPI from 1989 to 2006

In this case, the exponential function takes the form of:

$$Y = a \cdot e^{bX}$$

Eq. 10C.1

Where:

Y = warm air furnaces 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 heating equipment price index versus *year* from 1989 to 2006. See Figure 10C.2.2.

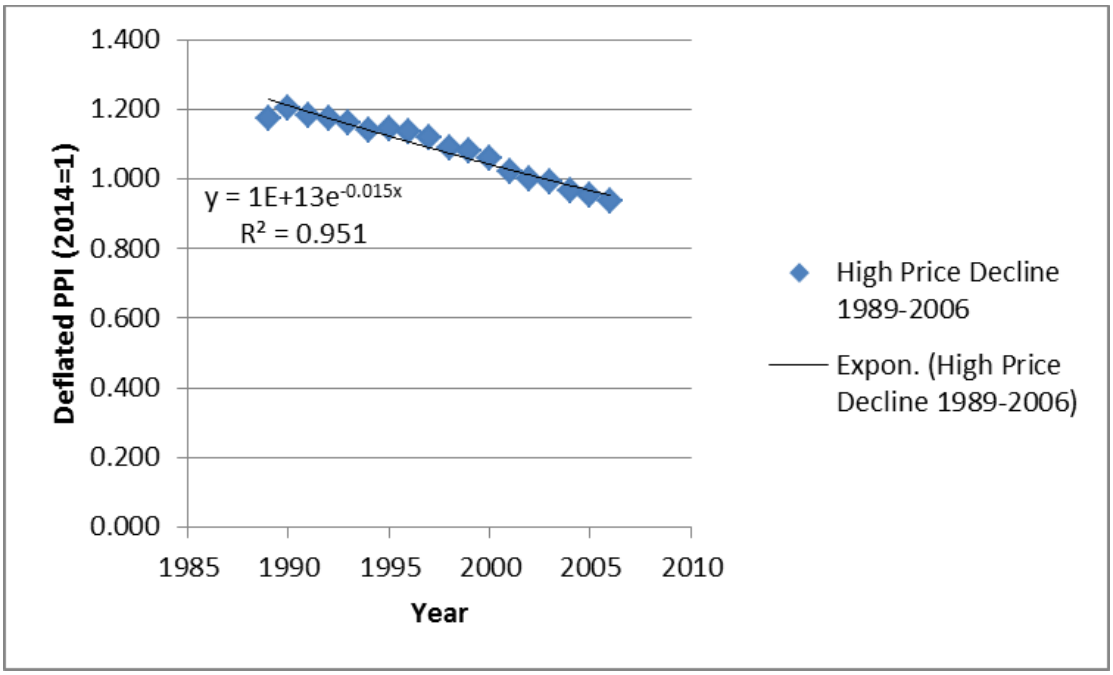

Figure 10C.2.2 Deflated Warm Air Furnaces PPI versus Year, with Exponential Fit from 1989 to 2006

The regression performed as an exponential trend line fit results in an R-square of 0.95, meaning a good fit to the data. The final estimated exponential function is:

$$Y = 1.040 \times 10^{13} \cdot e^{(-0.015)X}$$

DOE then derived a price factor index for this scenario, normalized to 2014, 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.2.3 Summary

Table 10C.2.1 shows the summary of the average annual rates of change for the product price index in each scenario. Figure 10C.2.3 shows the resulting price trends.

Table 10C.2.1 Price Trend Sensitivities

Sensitivity	Price Trend	Average Annual Rate of Change %
Medium (Default)	Exponential Fit using PPI from 1989 to 2014	-0.73
Low Price Decline	AEO2015 -" Chained price index—industrial equipment"	-0.02
High Price Decline	Exponential Fit using PPI from 1989 to 2006	-1.49

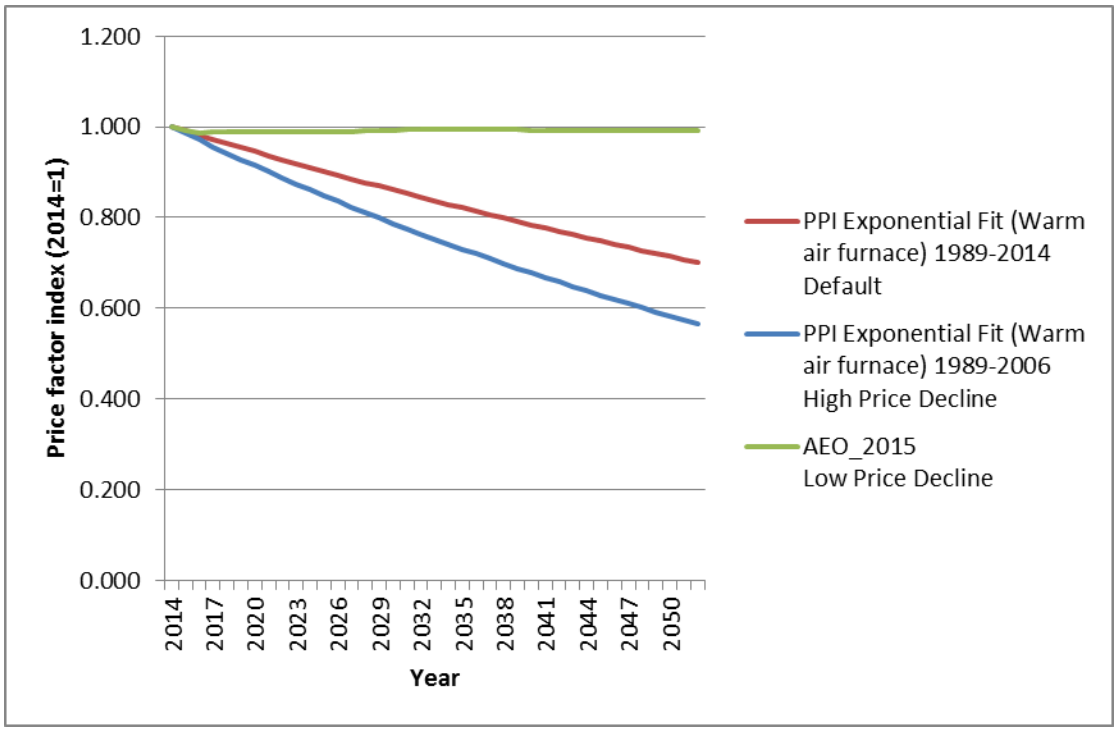

Figure 10C.2.3 Commercial Warm Air Furnaces Price Forecast Indexes

10C.3 NET PRESENT VALUE RESULTS USING ALTERNATIVE EQUIPMENT PRICE TRENDS

Table 10C.3.1 through Table 10C.3.6 present the NPV results using the alternative equipment price forecast for each key equipment class. Table 10C.3.7 compares the NPV using the three equipment price forecasts. The results are only slightly sensitive to the alternative equipment price forecasts.

Table 10C.3.1 NPV Using Reference Equipment Price Forecast, Discounted at 3 Percent, for Commercial Warm Air Furnaces (Billion 2014$)

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	1.066	0.964	-0.061	-0.061	2.463
Oil-fired Commercial Warm Air Furnace	0.000	0.010	0.000	0.011	0.141
Total	1.066	0.974	-0.061	-0.050	2.605

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10C.3.2 NPV Using Reference Equipment Price Forecast, Discounted at 7 Percent, for Commercial Warm Air Furnaces (Billion 2014$)

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.386	0.326	-0.360	-0.360	-0.402
Oil-fired Commercial Warm Air Furnace	0.000	0.003	0.000	0.004	0.036
Total	0.386	0.329	-0.360	-0.356	-0.366

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10C.3.3 NPV Using Alternative Equipment Price Forecast (High Price Decline Trend), Discounted at 3 Percent, for Commercial Warm Air Furnaces (Billion 2014$)

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	1.074	0.962	0.115	0.115	2.995
Oil-fired Commercial Warm Air Furnace	0.000	0.011	0.000	0.011	0.146
Total	1.074	0.973	0.115	0.127	3.142

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10C.3.4 NPV Using Alternative Equipment Price Forecast (High Price Decline Trend), Discounted at 7 Percent, for Commercial Warm Air Furnaces (Billion 2014$)

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.390	0.326	-0.273	-0.273	-0.150
Oil-fired Commercial Warm Air Furnace	0.000	0.003	0.000	0.004	0.038
Total	0.390	0.329	-0.273	-0.269	-0.112

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10C.3.5 NPV Using Alternative Equipment Price Forecast (Low Price Decline Trend), Discounted at 3 Percent, for Commercial Warm Air Furnaces (Billion 2014$)

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	1.052	0.965	-0.374	-0.374	1.515
Oil-fired Commercial Warm Air Furnace	0.000	0.011	0.000	0.011	0.132
Total	1.052	0.975	-0.374	-0.363	1.647

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10C.3.6 NPV Using Alternative Equipment Price Forecast (Low Price Decline Trend), Discounted at 7 Percent, for Commercial Warm Air Furnaces (Billion 2014$)

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.379	0.325	-0.511	-0.511	-0.844
Oil-fired Commercial Warm Air Furnace	0.000	0.003	0.000	0.004	0.031
Total	0.379	0.329	-0.511	-0.507	-0.812

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10C.3.7 Comparison of Total NPV Across All Equipment Classes for Alternative Equipment Price Forecast (Billion 2014$)

Price Trend Scenario	Discount Rate	Trial Standard Level				
		1	2*	3	4	5
Reference Case	3%	1.066	0.974	-0.061	-0.050	2.605
	7%	0.386	0.329	-0.360	-0.356	-0.366
High Decline Price Trend	3%	1.074	0.973	0.115	0.127	3.142
	7%	0.390	0.329	-0.273	-0.269	-0.112
Low Decline Price Trend	3%	1.052	0.975	-0.374	-0.363	1.647
	7%	0.379	0.329	-0.511	-0.507	-0.812

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

REFERENCES

1. 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 June 5, 2015.) http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

APPENDIX 10D. NATIONAL IMPACT ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR COMMERCIAL WARM AIR FURNACES

TABLE OF CONTENTS

10D.1 INTRODUCTION 10D-1
10D.2 DESCRIPTION OF HIGH AND LOW ECONOMIC SCENARIOS 10D-1
10D.3 RESULTS 10D-1
10D.3.1 National Energy Savings 10D-1
10D.3.2 Net Present Value of Consumer Impacts 10D-2
10D.3.3 Summary 10D-4

LIST OF TABLES

Table 10D.3.1 Primary National Energy Savings (Quads) – Reference Case 10D-2
Table 10D.3.2 Primary National Energy Savings (Quads) – High Economic Growth 10D-2
Table 10D.3.3 Primary National Energy Savings (Quads) – Low Economic Growth 10D-2
Table 10D.3.4 Net Present Value, Discounted at 3 Percent (Billion 2014$) – Reference Case 10D-2
Table 10D.3.5 Net Present Value, Discounted at 7 Percent (Billion 2014$) – Reference Case 10D-3
Table 10D.3.6 Net Present Value, Discounted at 3 Percent (Billion 2014$) – High Economic Growth 10D-3
Table 10D.3.7 Net Present Value, Discounted at 7 Percent (Billion 2014$) – High Economic Growth 10D-3
Table 10D.3.8 Net Present Value, Discounted at 3 Percent (Billion 2014$) – Low Economic Growth 10D-3
Table 10D.3.9 Net Present Value, Discounted at 7 Percent (Billion 2014$) – Low Economic Growth 10D-4
Table 10D.3.10 Comparison of Energy Savings and Net Present Value Results for Reference Case and High and Low Economic Growth Scenarios 10D-4

APPENDIX 10D. NATIONAL IMPACT ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR COMMERCIAL WARM AIR FURNACES

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) *Annual Energy Outlook 2015* (*AEO 2015*).[1] See appendix 8H 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 8H 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.

10D.3 RESULTS

10D.3.1 National Energy Savings

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 CWAF using the Reference Case, High Economic Growth, and Low Economic Growth scenarios.

Table 10D.3.1 Primary National Energy Savings (Quads) – Reference Case

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.221	0.204	0.362	0.362	2.065
Oil-fired Commercial Warm Air Furnace	0.000	0.001	0.000	0.001	0.014
Total	0.221	0.204	0.362	0.363	2.079

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.2 Primary National Energy Savings (Quads) – High Economic Growth

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.221	0.203	0.362	0.362	2.069
Oil-fired Commercial Warm Air Furnace	0.000	0.001	0.000	0.001	0.014
Total	0.221	0.204	0.362	0.363	2.082

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.3 Primary National Energy Savings (Quads) – Low Economic Growth

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.221	0.204	0.361	0.361	2.060
Oil-fired Commercial Warm Air Furnace	0.000	0.001	0.000	0.001	0.014
Total	0.221	0.205	0.361	0.362	2.074

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

10D.3.2 Net Present Value of Consumer Impacts

Table 10D.3.4 through Table 10D.3.9 show the national present value (NPV) results for each of the TSLs analyzed for CWAF using the 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.3.4 Net Present Value, Discounted at 3 Percent (Billion 2014$) – Reference Case

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	1.066	0.964	-0.061	-0.061	2.463
Oil-fired Commercial Warm Air Furnace	0.000	0.010	0.000	0.011	0.141
Total	1.066	0.974	-0.061	-0.050	2.605

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.5 Net Present Value, Discounted at 7 Percent (Billion 2014$) – Reference Case

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.386	0.326	-0.360	-0.360	-0.402
Oil-fired Commercial Warm Air Furnace	0.000	0.003	0.000	0.004	0.036
Total	0.386	0.329	-0.360	-0.356	-0.366

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.6 Net Present Value, Discounted at 3 Percent (Billion 2014$) – High Economic Growth

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	1.140	1.030	0.063	0.063	3.220
Oil-fired Commercial Warm Air Furnace	0.000	0.011	0.000	0.012	0.151
Total	1.140	1.041	0.063	0.075	3.371

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.7 Net Present Value, Discounted at 7 Percent (Billion 2014$) – High Economic Growth

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.410	0.346	-0.320	-0.320	-0.166
Oil-fired Commercial Warm Air Furnace	0.000	0.004	0.000	0.004	0.039
Total	0.410	0.350	-0.320	-0.316	-0.128

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.8 Net Present Value, Discounted at 3 Percent (Billion 2014$) – Low Economic Growth

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	1.021	0.925	-0.140	-0.140	2.055
Oil-fired Commercial Warm Air Furnace	0.000	0.010	0.000	0.011	0.133
Total	1.021	0.935	-0.140	-0.129	2.188

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

Table 10D.3.9 Net Present Value, Discounted at 7 Percent (Billion 2014$) – Low Economic Growth

Equipment Class	Trial Standard Levels				
	1	2*	3	4	5
Gas-fired Commercial Warm Air Furnace	0.370	0.313	-0.387	-0.387	-0.540
Oil-fired Commercial Warm Air Furnace	0.000	0.003	0.000	0.004	0.033
Total	0.370	0.316	-0.387	-0.383	-0.507

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

10D.3.3 Summary

Table 10D.3.10 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. NES and NPV results are larger for High Economic Growth scenario and smaller for Low Economic Growth scenario compared to Reference case.

Table 10D.3.10 Comparison of Energy Savings and Net Present Value Results for Reference Case and High and Low Economic Growth Scenarios

		Trial Standard Level				
		1	2*	3	4	5
Reference	Primary Energy Savings (quads)	0.221	0.204	0.362	0.363	2.079
	NPV at 3% (billion 2014$)	1.066	0.974	-0.061	-0.050	2.605
	NPV at 7% (billion 2014$)	0.386	0.329	-0.360	-0.356	-0.366
High Economic Growth	Primary Energy Savings (quads)	0.221	0.204	0.362	0.363	2.082
	NPV at 3% (billion 2014$)	1.140	1.041	0.063	0.075	3.371
	NPV at 7% (billion 2014$)	0.410	0.350	-0.320	-0.316	-0.128
Low Economic Growth	Primary Energy Savings (quads)	0.221	0.205	0.361	0.362	2.074
	NPV at 3% (billion 2014$)	1.021	0.935	-0.140	-0.129	2.188
	NPV at 7% (billion 2014$)	0.370	0.316	-0.387	-0.383	-0.507

* The compliance year is 2023 for TSL 2 and 2019 for other TSLs.

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1. 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 June 5, 2015.) http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

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CHAPTER 11. CONSUMER SUBGROUP ANALYSIS

TABLE OF CONTENTS

11.1 INTRODUCTION 11-1
11.2 SUBGROUP DEFINITIONS 11-1
11.2.1 Commercial Consumer Subgroup 11-1
11.2.2 Small Business Commercial Discount Rate 11-8
11.3 LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR SMALL BUSINESS SUBGROUP 11-9

LIST OF TABLES

Table 11.2.1 NAICS Industries by Building Type 11-2
Table 11.2.2 Example of Establishment Categories: Educational Services NAICS 611 11-4
Table 11.2.3 Maximum Number of Employees in Small Business by Building Type 11-7
Table 11.2.4 Discount Rate Difference between Small Company and Sector Average 11-9
Table 11.3.1 Average LCC and PBP Results by Efficiency Level for Gas-Fired Commercial Warm Air Furnaces for Small Businesses 11-10
Table 11.3.2 LCC Savings Relative to the Base Case Efficiency Distribution for Gas-Fired Commercial Warm Air Furnaces for Small Businesses 11-10
Table 11.3.3 Average LCC and PBP Results by Efficiency Level for Oil-Fired Commercial Warm Air Furnaces for Small Businesses 11-10
Table 11.3.4 LCC Savings Relative to the Base Case Efficiency Distribution for Oil-Fired Commercial Warm Air Furnaces for Small Businesses 11-11
Table 11.3.5 Comparison of Average LCC Savings and Median Payback Period Results for Consumer Subgroups and All Buildings 11-11

LIST OF FIGURES

Figure 11.2.1 Assembly: Relationship between Number of Employees and Value of Sales 11-5
Figure 11.2.2 Education: Relationship between Number of Employees and Value of Sales 11-5
Figure 11.2.3 Food Service: Relationship between Number of Employees and Value of Sales 11-6
Figure 11.2.4 Office: Relationship between Number of Employees and Value of Sales 11-6
Figure 11.2.5 Retail: Relationship between Number of Employees and Value of Sales 11-7

CHAPTER 11. CONSUMER SUBGROUP ANALYSIS

11.1 INTRODUCTION

The life-cycle cost (LCC) consumer subgroup analysis evaluates impacts on any identifiable groups of commercial consumers of commercial warm air furnaces (CWAF) who may be disproportionately affected by a national energy efficiency standard. DOE accomplished this, in part, by analyzing the LCC and payback period (PBPs) for those commercial consumers that fall into specific subgroups.

DOE determined the impact on commercial consumer subgroups using the LCC spreadsheet model. The standard LCC and PBP analysis (described in chapter 8) includes various types of commercial buildings that use CWAF equipment. The LCC spreadsheet model allows for the identification of certain subgroups of commercial buildings which can then be analyzed by sampling only that subgroup. (Chapter 8 explains in detail the inputs to the spreadsheet model used in determining the LCC and PBP.)

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 SUBGROUP DEFINITIONS

11.2.1 Commercial Consumer Subgroup

DOE identified small businesses as a subgroup that possibly could be disproportionately affected by CWAF efficiency standards. DOE was concerned that increases in the purchase price of equipment could have negative impacts on small businesses (*i.e.*, those with low annual revenues).

From the building sample used in the LCC and PBP analysis, DOE identified which buildings contain small businesses. To identify buildings used by small businesses, the Department used size standards from the Small Business Administration (SBA) to define which business entities are considered to be small. The SBA established size standards for types of economic activity, or industry, under the North American Industry Classification System (NAICS).[1] The building sample used in DOE's LCC and PBP analysis was defined by the building energy use and end-use load characterization analysis (chapter 7). The building sample consisted of the following six building types: assembly (*e.g.*, performing arts facilities), education, food services, office, retail, and warehouses (non-refrigerated). For each of these six building types, DOE selected and assigned specific representative economic activities from the NAICS, as summarized in Table 11.2.1.

Table 11.2.1 NAICS Industries by Building Type

Building Type	NAICS Industry	
	Code	**Industry Title**
Assembly	711 712 713	Performing arts spectator sports & related industries Museums, historical sites, & similar institutions Amusement, gambling, & recreation industries
Education	611	Educational Services
Food Service	722	Food services & drinking places
Office	5222 523 5242 531 532 533 541 621	Nondepository credit intermediation Securities intermediation & related activities Agencies, brokerages & other insurance related activities Real estate Rental & leasing services Lessors of intangible assets except copyrighted works Professional, scientific, & technical services Ambulatory health care services
Retail	441 442 443 444 445 446 447 448 451 452 453 811 812	Motor vehicle & parts dealers Furniture & home furnishings stores Electronics & appliance stores Building material & garden equipment & supplies dealers Food & beverage stores Health & personal care stores Gasoline stations Clothing & clothing accessories stores Sporting goods, hobby, book and music stores General merchandise stores Miscellaneous store retailers Repair and maintenance Personal and laundry services
Warehouse	423 424	Merchant wholesalers, durable goods Merchant wholesalers, nondurable goods

The SBA defines a small business by either its annual receipts (*i.e.*, revenues) or its number of employees. Assembly, education, food services, office, and retail businesses are generally defined to be small if annual receipts are $6 million or less. Businesses located in warehouses are considered to be small if they employ 100 or fewer people.

As described in the building energy use and end-load characterization analysis, DOE drew its building sample from the 2003 Commercial Building Energy Consumption Survey (CBECS 2003).[2,3]

CBECS 2003 provides the number of workers employed, but not the annual revenues for each of the records in its building sample. Thus, DOE needed to correlate annual revenues with the number of workers to identify the subgroup of small businesses in the building sample. Because some individual CBECS 2003 building records could represent businesses that are part

of much larger firms, the small business subgroup identified by DOE could possibly over-represent the actual number of small businesses. However, DOE feels that the results from the analysis provide an adequate indication of whether the small business subgroup would be disproportionally advantaged or disadvantaged by a proposed standard.

DOE used *Establishment and Firm Size* data series from the U.S. Census Bureau 2007 Economic Census to define the relationship between annual revenues and the number of workers for each of the relevant business activities (assembly,[4] education,[5] food services,[6] office,[7–10] and retail[11,12]). The Census data series provide annual receipts, the number of paid employees, and the number of establishments by categories of establishments. Establishment categories are based on a range of annual receipts (*e.g.*, establishments with receipts of $1 million to less than $2.5 million). Within each establishment category, DOE determined an average value for annual receipts by dividing the annual receipts by the number of establishments. It performed the same type of calculation to arrive at an average number of paid employees for each establishment category. To more clearly demonstrate how DOE used the Census Bureau data, Table 11.2.2 provides a listing of establishment categories for educational services (NAICS code 611). The primary data in Table 11.2.2 are drawn directly from the *Education Service Establishment and Firm Size* data series. The derived data (average receipts and average number of employees) are in the two right-hand columns. Note that the upper limit of what is considered a small business ($6 million annual receipts) falls within the establishment category of $5 million to $9.99 million.

Table 11.2.2 Example of Establishment Categories: Educational Services NAICS 611

Primary Data from 2007 Economic Census *Educational Services, Establishment and Firm Size* data series				**Derived Data**	
Sales size of establishment	**Establishments**	**Receipts ($1000)**	**Employees**	**Average Receipts ($)**	**Average Employees**
Establishments with sales less than $10,000	836	$5,462	1,075	$6,533	1
Establishments with sales of $10,000 to $24,999	2,166	$36,016	2,529	$16,628	1
Establishments with sales of $25,000 to $50,000	3,506	$129,055	5,759	$36,810	2
Establishments with sales of $50,000 to $99,999	6,609	$489,081	16,392	$74,002	2
Establishments with sales of $100,000 to $249,999	13,331	$2,217,064	58,906	$166,309	4
Establishments with sales of $250,000 to $499,999	9,838	$3,490,316	78,894	$354,779	8
Establishments with sales of $500,000 to $999,999	6,523	$4,542,752	82,984	$696,421	13
Establishments with sales of $1,000,000 to $2,499,999	4,373	$6,596,468	87,150	$1,508,454	20
Establishments with sales of $2,500,000 to $4,999,999	1,467	$5,049,354	53,541	$3,441,959	36
Establishments with sales of $5,000,000 to $9,999,999	781	$5,360,243	46,676	$6,863,307	60
Establishments with sales of $10,000,000 or more	534	$15,227,571	78,633	$28,516,051	147

By deriving the average receipts and numbers of employees for the establishment categories within each of the NAICS industries listed in Table 11.2.1, DOE was able to create a data set from which to establish a relationship between receipts (revenues) and number of employees (workers) for five of the building types listed in Table 11.2.1. Figure 11.2.1 through Figure 11.2.5 plot the receipt and employee data sets for each of the five building types. Because the SBA generally defines small businesses as those with annual revenues of $6 million or less, DOE plotted only data from establishment categories up to and including "establishments with sales of $5 million to $9.99 million" in Figure 11.2.1 through Figure 11.2.5. DOE did not provide a figure for warehouses because, as noted earlier, businesses located in warehouses are considered to be small if they employ 100 or fewer people.

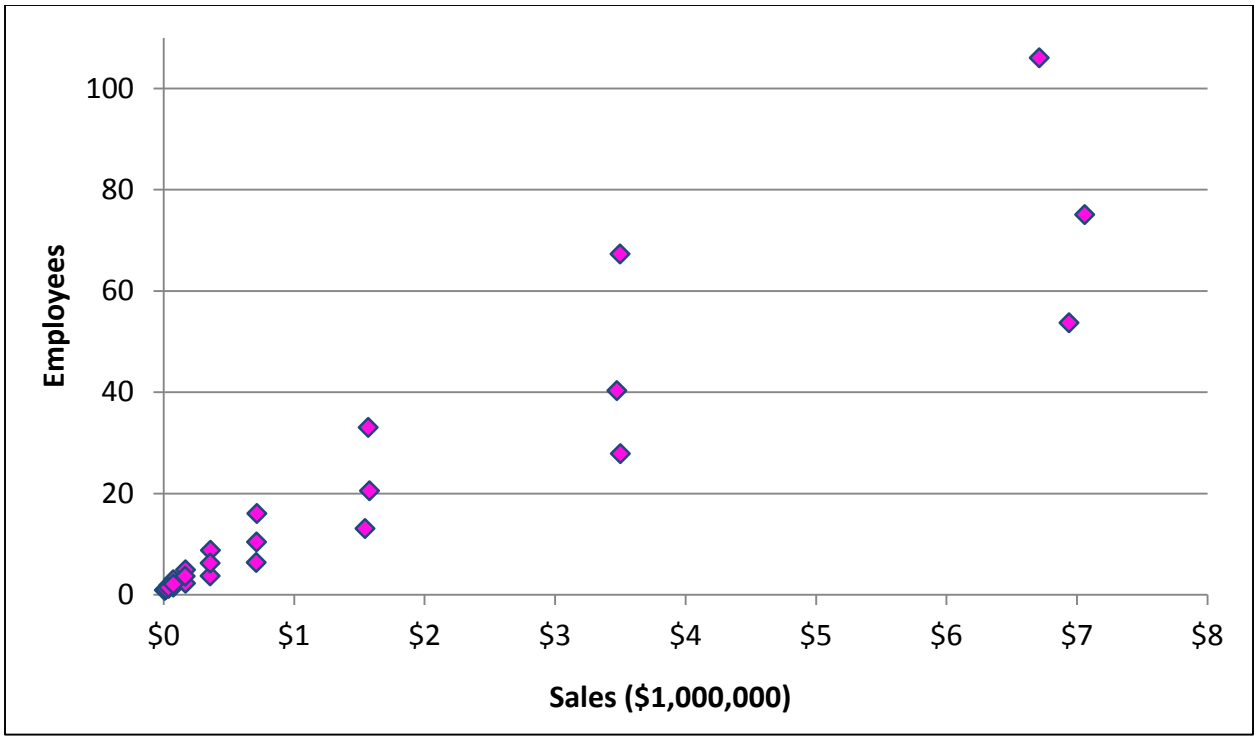

Figure 11.2.1 Assembly: Relationship between Number of Employees and Value of Sales

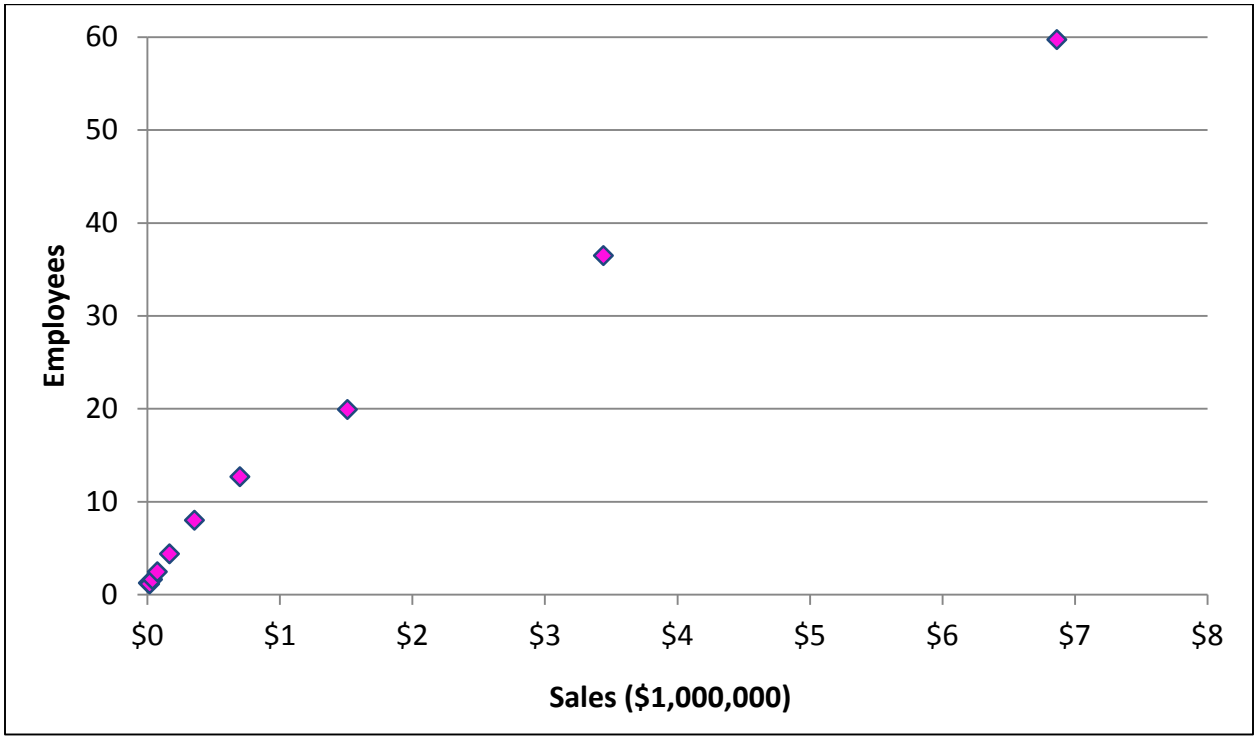

Figure 11.2.2 Education: Relationship between Number of Employees and Value of Sales

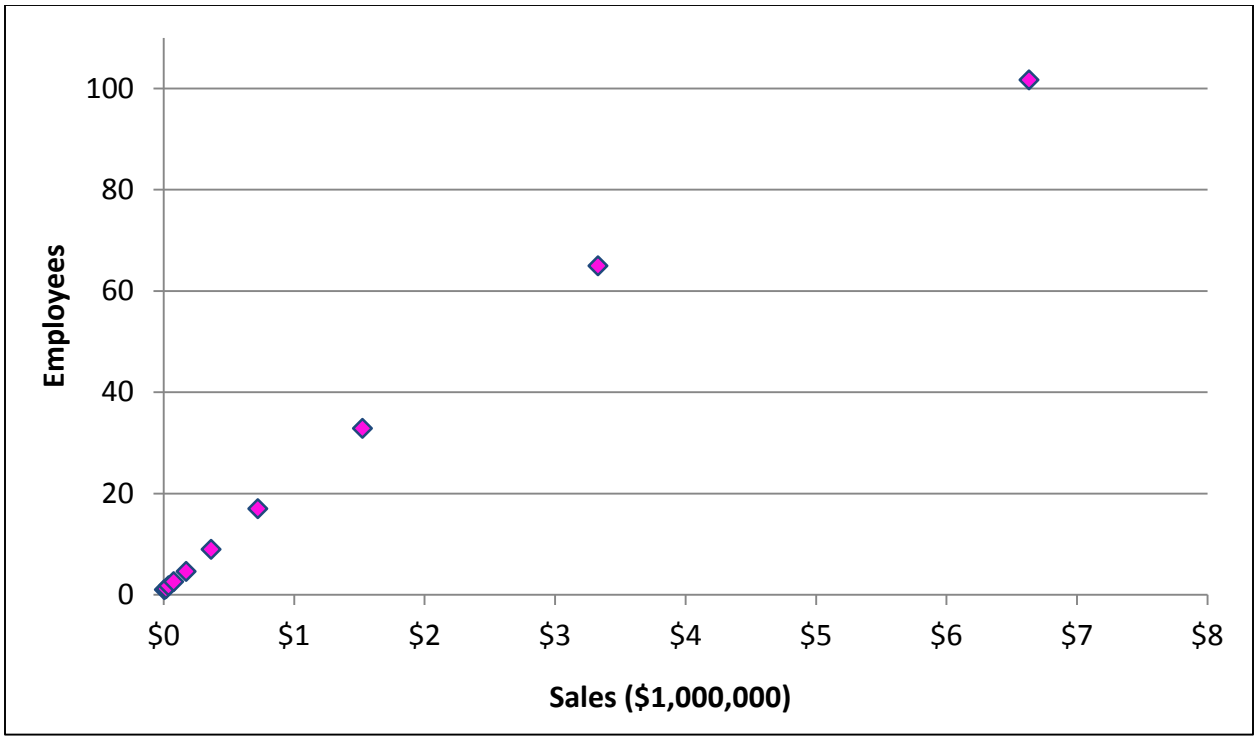

Figure 11.2.3 **Food Service: Relationship between Number of Employees and Value of Sales**

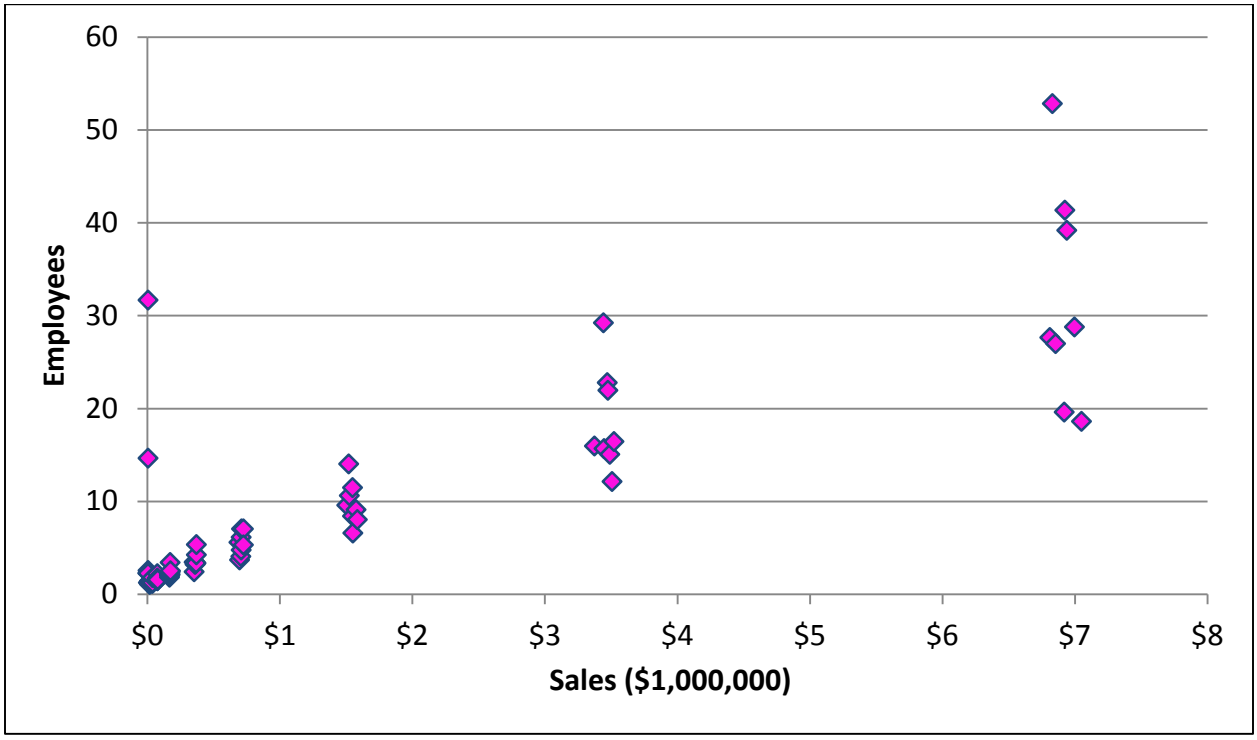

Figure 11.2.4 **Office: Relationship between Number of Employees and Value of Sales**

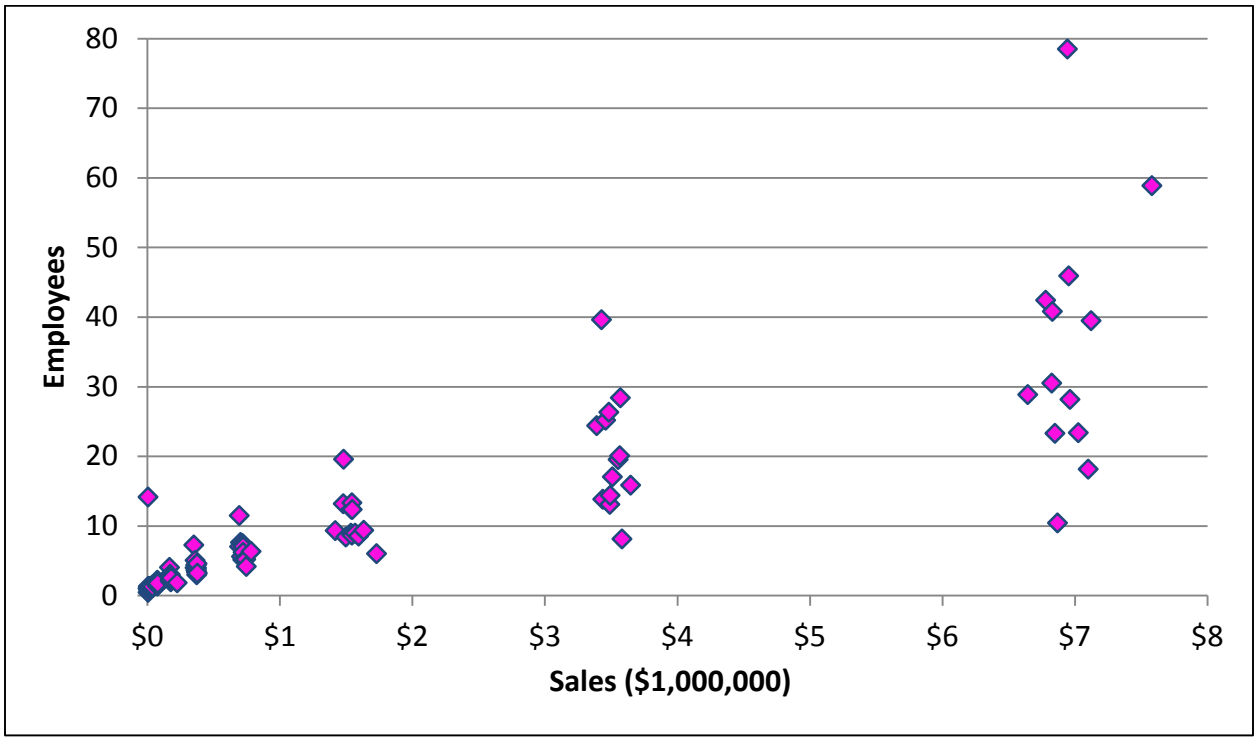

Figure 11.2.5 Retail: Relationship between Number of Employees and Value of Sales

Using the data in Figure 11.2.1 through Figure 11.2.5, DOE estimated the relationship between annual value of sales and number of employees for each building type through linear regression. Based on the regression parameters, DOE then estimated the number of employees for the assembly, education, food services, office, and retail building types associated with annual sales of $6 million.

Table 11.2.3 Maximum Number of Employees in Small Business by Building Type

Building Type	Maximum Number of Employees
Assembly	70
Education	55
Food Service	98
Office	28
Retail	32
Warehouse	100

With small businesses identified by the number of workers for each building type, DOE was able to identify from its building sample which buildings could potentially be occupied by small businesses. DOE created the small business subgroup by selecting the CBECS 2003 buildings in the commercial buildings sample with fewer employees than shown in Table 11.2.3

by building type. The small business subgroup represents approximately 50 percent of floor space in the full building sample.

11.2.2 Small Business Commercial Discount Rate

The Small Business Administration (SBA) defines a small business by its annual receipts or its number of employees. CWAF are used throughout the U.S. economy, so DOE did not assign a different distribution of CWAF applications or sectors of the economy to this subgroup.

The capital asset pricing model (CAPM) underestimates the cost of capital for small companies. In CAPM, the risk premium β is used to account for the higher returns associated with greater risk. However, for small companies, particularly very small companies, historic returns have been significantly higher than the CAPM equation predicts. This additional return can be accounted for by adding a size premium to the cost of equity for small firms:

$$k_e = R_f + (\beta \times ERP) + S$$

Eq. 11.1

Where:

k_e = cost of equity,
R_f = expected return on risk-free assets,
β = risk coefficient of the firm,
ERP = equity risk premium, and
S = size premium.

DOE obtained size premium data from Ibbotson Associates' *Stocks, Bonds, Bills, and Inflation 2009 Yearbook*.[13] For the period of 1926-2008, the average size premium for the smallest companies in all industries is 5.81 percent, implying that on average, historic performance of small companies has been 5.81 percent higher than the CAPM estimate of the small company cost of equity.[a]

DOE calculated the real weighted average cost of capital (as described in chapter 8) using the cost of equity including a size premium for small companies instead of the CAPM cost of equity.[14] Table 11.2.4 presents DOE's estimates of the discount rates for entire sectors, small companies specifically, and the small company discount rate premium.

To estimate the impact of standards specifically on small businesses, the small company discount rates for each sector were used in the life-cycle cost and payback period analysis instead of the sector average discount rates.

---

[a] In this calculation, small companies are defined as companies with market capitalization of less than or equal to $218.53 million, the Ibbotson Associates' definition of Decile 10 companies.

Table 11.2.4 Discount Rate Difference between Small Company and Sector Average

Sector*		Discount Rate		
		Average (%)	Std Dev (%)	Small Company Discount Rate Premium (%)
Retail	Entire Sector	4.30	2.09	**4.37**
	Small Companies	**8.66**	3.17	
Property Owners	Entire Sector	5.16	1.30	**3.20**
	Small Companies	**8.36**	2.08	
Medical Services	Entire Sector	4.19	1.86	**4.10**
	Small Companies	**8.30**	2.47	
Industrial	Entire Sector	4.95	1.92	**3.74**
	Small Companies	**8.69**	3.16	
Hotels	Entire Sector	5.88	2.28	**2.66**
	Small Companies	**8.53**	3.00	
Food Service	Entire Sector	4.84	2.60	**3.08**
	Small Companies	**7.91**	3.13	
Office	Entire Sector	5.40	1.85	**2.15**
	Small Companies	**7.56**	3.03	
Other	Entire Sector	4.35	1.64	**4.05**
	Small Companies	**8.40**	3.32	

* Note that it is not appropriate to calculate a separate small company discount rate for public sectors.

11.3 LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR SMALL BUSINESS SUBGROUP

Table 11.3.1 through Table 11.3.4 summarize the LCC and PBP results for the small business subgroup for each of the CWAF equipment classes. Table 11.3.5 compares them to the results for the total sample of buildings used in the overall LCC analysis. Results are provided by efficiency level (EL). Note that this is an overestimate of the impact on small businesses; many small buildings may be owned by the same company, as is the case with retail and restaurant chains. As is evident from the LCC and PBP results, the CWAF ELs are less favorable for small businesses than for the full sample of commercial consumers. The average LCC savings is still positive except for EL 2 for gas-fired CWAF.

Table 11.3.1 Average LCC and PBP Results by Efficiency Level for Gas-Fired Commercial Warm Air Furnaces for Small Businesses

Efficiency Level	TE	Average Costs *2014$*				Simple Payback *years*	Average Lifetime
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	80%	$2,087	$1,591	$23,369	$25,456	--	23
1	81%	$2,115	$1,574	$23,118	$25,233	1.6	23
2	82%	$2,544	$1,558	$22,877	$25,421	13.8	23
3	92%	$3,841	$1,446	$21,169	$25,010	12.1	23

Note: The results for each EL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

Table 11.3.2 LCC Savings Relative to the Base Case Efficiency Distribution for Gas-Fired Commercial Warm Air Furnaces for Small Businesses

Efficiency Level	TE	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	80%	0%	--
1	81%	6.5%	$223
2	82%	65.4%	-$28
3	92%	64.4%	$377

* The calculation excludes buildings with zero LCC savings (no impact).

Table 11.3.3 Average LCC and PBP Results by Efficiency Level for Oil-Fired Commercial Warm Air Furnaces for Small Businesses

Efficiency Level	TE	Average Costs *2014$*				Simple Payback *years*	Average Lifetime
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	81%	$6,414	$2,473	$38,916	$45,329	--	23
1	82%	$6,466	$2,447	$38,494	$44,961	2.0	23
2	92%	$7,904	$2,256	$35,453	$43,357	6.9	23

Note: The results for each EL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

Table 11.3.4 LCC Savings Relative to the Base Case Efficiency Distribution for Oil-Fired Commercial Warm Air Furnaces for Small Businesses

Efficiency Level	TE	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	81%	0%	--
1	82%	7.8%	$378
2	92%	49.7%	$1,754

* The calculation excludes buildings with zero LCC savings (no impact).

Table 11.3.5 Comparison of Average LCC Savings and Median Payback Period Results for Consumer Subgroups and All Buildings

Equipment Class	Efficiency Level	Average LCC Savings *2014$*		Simple Payback Period *Years*	
		Small Businesses	All	Small Businesses	All
Gas-Fired	1	$223	$284	1.6	1.4
	2	-$28	$75	13.8	12.3
	3	$377	$766	12.1	11.3
Oil-Fired	1	$378	$400	2.0	1.9
	2	$1,754	$1,817	6.9	7.5

Note: The results for each EL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

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CHAPTER 12. CWAF MANUFACTURER IMPACT ANALYSIS

TABLE OF CONTENTS

12.1 INTRODUCTION 12-1
12.2 METHODOLOGY 12-1
12.2.1 Phase I: Industry Profile 12-1
12.2.2 Phase II: Industry Cash-Flow Analysis and Interview Guide 12-2
12.2.2.1 Industry Cash-Flow Analysis 12-2
12.2.2.2 Interview Guide 12-2
12.2.3 Phase III: Subgroup Analysis 12-3
12.2.3.1 Manufacturing Interviews 12-3
12.2.3.2 Revised Industry Cash-Flow Analysis 12-3
12.2.3.3 Manufacturer Subgroup Analysis 12-3
12.2.3.4 Small-Business Manufacturer Subgroup 12-4
12.2.3.5 Manufacturing Capacity Impact 12-5
12.2.3.6 Employment Impact 12-5
12.2.3.7 Cumulative Regulatory Burden 12-5
12.3 GRIM INPUTS AND ASSUMPTIONS 12-5
12.3.1 Overview of the GRIM 12-5
12.3.2 Sources for GRIM Inputs 12-6
12.3.2.1 Corporate Annual Reports 12-6
12.3.2.2 Standard and Poor Credit Ratings 12-7
12.3.2.3 Shipment Model 12-7
12.3.2.4 Engineering Analysis 12-7
12.3.2.5 Manufacturer Interviews 12-7
12.3.3 Financial Parameters 12-8
12.3.4 Corporate Discount Rate 12-9
12.3.5 Trial Standard Levels 12-11
12.3.6 NIA Shipments 12-12
12.3.7 Production Costs 12-12
12.3.8 Conversion Costs 12-13
12.3.8.1 Capital Conversion Costs 12-14
12.3.8.2 Production Conversion Costs 12-14
12.3.9 Markup Scenarios 12-15
12.3.9.1 Preservation of Gross Margin Percentage Scenario 12-15
12.3.9.2 Preservation of Operating Profit Scenario 12-16
12.4 INDUSTRY FINANCIAL IMPACTS 12-16
12.4.1 Introduction 12-16
12.4.2 CWAF Industry Financial Impacts 12-17
12.5 IMPACTS ON SMALL BUSINESS MANUFACTURERS 12-18
12.6 OTHER IMPACTS 12-20
12.6.1 Direct Employment 12-20
12.6.2 Production Capacity 12-22
12.6.3 Cumulative Regulatory Burden 12-22

12.7 CONCLUSION 12-24
REFERENCES 12-27

LIST OF TABLES

Table 12.1 SBA and NAICS Classification of Small Businesses Potentially Affected by This Rulemaking 12-4
Table 12.2 Financial Parameters Used for GRIM Analysis (Based on 2006-2011 Company Financial Data) 12-8
Table 12.3 Financial Parameters Used to Determine No-New-Standards Case Markup 12-8
Table 12.4 No-New-Standards Case Manufacturer Markups 12-9
Table 12.5 Financial Parameters used for CWAF GRIM 12-9
Table 12.5 Cost of Equity Calculation 12-10
Table 12.6 Cost of Debt Calculation 12-11
Table 12.6 Trial Standard Levels for Energy Efficiency Analysis of CWAF Equipment 12-12
Table 12.7 Manufacturer Production Cost Breakdown ($2014) for Gas-fired CWAF 12-13
Table 12.8 Manufacturer Production Cost Breakdown ($2014) for Oil-fired CWAF 12-13
Table 12.9 Industry Cumulative Capital Conversion Cost by Efficiency Level 12-14
Table 12.10 Industry Cumulative Capital Conversion Costs by TSL 12-14
Table 12.11 Industry Cumulative Product Conversion Cost by Efficiency Level 12-15
Table 12.12 Industry Cumulative Product Conversion Costs by TSL 12-15
Table 12.13 Preservation of Gross Margin Percentage / Low Conversion Cost Scenario: Changes in INPV 12-18
Table 12.14 Preservation of Gross Margin Percentage / High Conversion Cost Scenario: Changes in INPV 12-18
Table 12.15 Preservation of Operating Profit Scenario / Low Conversion Costs Scenario: Changes in INPV 12-18
Table 12.16 Preservation of Operating Profit Scenario / High Conversion Costs Scenario: Changes in INPV 12-18
Table 12.17 Potential Changes in Total Number of Domestic Employment Workers in the CWAF Industry in 2019 12-20
Table 12.18 Percentage of Products Retired to Meet Amended Standard Levels 12-21
Table 12.19 Compliance Dates and Expected Conversion Expenses of Federal Energy Conservation Standards Affecting CWAF Manufacturers 12-23

LIST OF FIGURES

Figure 12-1 Using the GRIM to Calculate Cash Flow 12-6

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 on the 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 CWAF equipment, 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 and the various trial standard levels (TSLs) in the standards case. The qualitative part of the MIA addresses product characteristics, manufacturer characteristics, 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 CWAF industry, including 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 developed interview guides to gather information on the potential impacts on these manufacturers. In Phase III, "Subgroup Impact Analysis," DOE interviewed manufacturers representing a broad cross-section of the CWAF industry. Using information from Phase II, DOE refined its analysis in the GRIM, developed additional analyses for subgroups that required special consideration, and incorporated qualitative data from interviews into its analysis.

12.2.1 Phase I: Industry Profile

In Phase I of the MIA, DOE prepared a profile of the CWAF industry that built on the market and technology assessment prepared for this rulemaking (refer to chapter 3 of the technical support document (TSD)). Before initiating the detailed impact studies, DOE collected information on the present and past structure and market characteristics of the CWAF industry. This information included shipments, manufacturer markups, and the cost structures of various manufacturers. The industry profile includes: (1) further detail on the overall market and product characteristics; (2) estimated manufacturer market shares; (3) financial parameters such as net plant, property, and equipment; selling, general and administrative (SG&A) expenses; cost of goods sold, etc.; and (4) trends in the number of firms, market, and product characteristics. The

industry profile included a top-down cost analysis of CWAF equipment manufacturers that DOE used to derive the preliminary financial inputs for the GRIM (*e.g.*, revenues, depreciation, SG&A, and research and development (R&D) expenses).

DOE also used public information to further 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.*, Hoovers[3]), corporate annual reports, and the U.S. Census Bureau's 2013 Annual Survey of Manufacturers (ASM).[4] DOE also characterized these industries using information from its engineering analysis and the life-cycle cost analysis.

12.2.2 Phase II: Industry Cash-Flow Analysis and Interview Guide

Phase II focused on the financial impacts of potential amended energy conservation standards on manufacturers of CWAF equipment. More-stringent energy conservation standards can affect manufacturer cash flows in three distinct ways, as it can: (1) create a need for increased investment; (2) raise production costs per unit; and (3) alter 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 CWAF industry. In performing these analyses, DOE used the financial values derived during Phase I and the shipment scenarios used in the national impact analysis (NIA). In Phase II, DOE performed these preliminary industry cash-flow analyses and prepared written guides for manufacturer interviews.

12.2.2.1 Industry Cash-Flow Analysis

The GRIM uses several factors to determine a series of annual cash flows from the announcement year of amended energy conservation standards until 30 years after the standards' compliance date. These factors include annual expected revenues, costs of goods sold, SG&A, taxes, and capital expenditures related to the amended standards. Inputs to the GRIM include manufacturer production costs, markup assumptions, and shipments forecasts developed in other analyses. DOE derived the manufacturing costs from the engineering analysis and information provided by the industry. It estimated typical manufacturer markups from public 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. The financial parameters were developed using publicly available manufacturer data and were revised with information submitted confidentially during manufacturer interviews. The GRIM results are compared to no-new-standards case projections for the industry. The financial impact of amended energy conservation standards is the difference between the discounted annual cash flows in the no-new-standards case and standards case at each TSL.

12.2.2.2 Interview Guide

During Phase II of the MIA, DOE also prepared an interview guide and distributed it to manufacturers for review and consideration prior to conducting interviews as part of Phase III. The interview guide provided a starting point for identifying relevant issues and impacts of amended energy conservation standards on individual manufacturers or subgroups of

manufacturers. Most of the information received from these meetings is protected by non-disclosure agreements and resides with DOE's contractors. The MIA interview topics included (1) key issues; (2) characteristics and technology; (3) conversion costs; (4) distribution channels; (5) market share, product mix, and industry consolidation; (6) cumulative regulatory burden; (7) financial parameters; (8) small business issues; and (9) other issues.

Appendix 12A contains the interview guide prepared and distributed to CWAF manufacturers as part of Phase III of the MIA.

12.2.3 Phase III: Subgroup Analysis

For its GRIM analysis, DOE presented the impacts on all equipment classes of CWAF as a whole. DOE sought to obtain feedback from industry on the approaches used in the GRIM, on key issues and concerns, and on industry sub-groups that require additional analysis.

12.2.3.1 Manufacturing 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. The interview process provides an opportunity for manufacturers to express their views on important issues privately, allowing confidential or sensitive information to be considered in the rulemaking process. DOE sought to obtain feedback from industry on the approaches used in the GRIMs and to isolate key issues and concerns.

DOE used these interviews to tailor the GRIM to reflect financial characteristics unique to the CWAF industry. Interviews were scheduled well in advance to provide every opportunity for key individuals to be available for comment. Although a written response to the questionnaire was acceptable, DOE sought interactive interviews, which help clarify responses and identify additional issues. The resulting information provides valuable inputs to the GRIM developed for the equipment classes.

12.2.3.2 Revised Industry Cash-Flow Analysis

In Phase II of the MIA, DOE provided manufacturers with preliminary GRIM input financial figures for review and evaluation. During the interviews, DOE requested comments on the values it selected for the parameters. DOE revised its industry cash-flow model based on this feedback. Section 12.3.3 provides more information on how DOE calculated the parameters.

12.2.3.3 Manufacturer Subgroup Analysis

Using average cost assumptions to develop an industry cash-flow estimate may not adequately assess differential impacts of amended energy conservation standards among 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. To address this possible impact, DOE used the results of the industry characterization analysis in Phase I to group manufacturers that exhibit similar characteristics.

During the interviews, DOE discussed the potential subgroups and subgroup members it identified for the analysis. DOE asked manufacturers and other interested parties to suggest what subgroups or characteristics are the most appropriate to analyze. As described in section 12.2.3, DOE presents the industry impacts on CWAF equipment manufacturers as a whole because most of the equipment classes represent the same market served by the same manufacturers. However, as discussed below, DOE identified one manufacturer subgroup that warranted a separate impact analysis: small manufacturers.

12.2.3.4 Small-Business Manufacturer Subgroup

DOE investigated whether small business manufacturers should be analyzed as a manufacturer subgroup. DOE used the Small Business Administration (SBA) small business size standards effective on November 5, 2010, as amended, and the North American Industry Classification System (NAICS) code, presented in Table 12.1, to determine whether any small entities would be affected by the rulemaking.[5] For the equipment classes under review, the SBA bases its small business definition on the total number of employees for a business, its subsidiaries, and its parent companies. An aggregated business entity with fewer employees than the listed limit is considered a small business.

Table 12.1 SBA and NAICS Classification of Small Businesses Potentially Affected by This Rulemaking

Industry Description	Revenue Limit	Employee Limit	NAICS
Air−conditioning and Warm Air Heating Equipment and Commercial and Industrial Refrigeration Equipment Manufacturing	N/A	750	333415

DOE used publicly available and proprietary information to identify potential small manufacturers. DOE's research involved industry trade association membership directories (including AHRI[a]) , individual company websites, and market research tools (e.g., Hoovers reports[b]) to create a list of companies that manufacture or sell the CWAF equipment covered by this rulemaking. DOE also asked industry representatives if they were aware of any other small manufacturers during manufacturer interviews. DOE reviewed publicly-available data and contacted companies on its list, as necessary, to determine whether they met the SBA's definition of a small business manufacturer of covered CWAF equipment. DOE screened out companies that do not offer equipment covered by this rulemaking, do not meet the definition of a "small business," or are foreign-owned and operated. DOE was able to determine that two manufacturers meet the SBA's definition of a "small business" and manufacture products covered by this rulemaking.

Based on this analysis, DOE identified two small business manufacturers of CWAF equipment. DOE reports the potential impact of this rulemaking on the small manufacturer in section 12.5.

[a] Based on listings in the AHRI directory accessed on August 2, 2013 (Available at: https://www.ahridirectory.org/ahridirectory/pages/home.aspx).
[b] Hoovers | Company Information | Industry Information | Lists, D&B (2013) (Available at: http://www.hoovers.com/) (Last accessed April 3, 2013).

12.2.3.5 Manufacturing Capacity Impact

One significant outcome of amended energy conservation standards could be the obsolescence of existing manufacturing assets, including tooling and investment. The manufacturer interview guides have a series of questions to help identify impacts of amended standards on manufacturing capacity, specifically capacity utilization and plant location decisions in the United States, with and without amended standards; the ability of manufacturers to upgrade or remodel existing facilities to accommodate the new requirements; the nature and value of any stranded assets; and estimates for any one-time changes to existing plant, property, and equipment (PPE). 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 12.3.9. DOE's discussion of the capacity impact can be found in section 12.6.3.

12.2.3.6 Employment Impact

The impact of amended energy conservation standards on employment is an important consideration in the rulemaking process. To assess how domestic direct employment patterns might be affected, the interviews explored current employment trends in the CWAF industry. The interviews also solicited manufacturer views on changes in employment patterns that may result from more stringent standards. The employment impacts section of the interview guide focused on current employment levels associated with manufacturers at each production facility, expected future employment levels with and without amended energy conservation standards, and differences in workforce skills and issues related to the retraining of employees. The employment impacts are reported in section 12.6.1.

12.2.3.7 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 other Federal regulations that impact other products made by the CWAF manufacturers. Discussion of the cumulative regulatory burden can be found in section 12.6.4.

12.3 GRIM INPUTS AND ASSUMPTIONS

The GRIM 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. Data and assumptions from these sources are then fed into an accounting model that calculates the industry cash flow both with and without amended energy conservation standards.

12.3.1 Overview of the GRIM

The basic structure of the GRIM, illustrated in Figure 12-1, 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 a number of inputs to arrive at a series of annual cash flows, beginning with the base year of the analysis, 2015, and continuing

to 2048. The model calculates the INPV by summing the stream of annual discounted cash flows during this period and adding a discounted terminal value.[6]

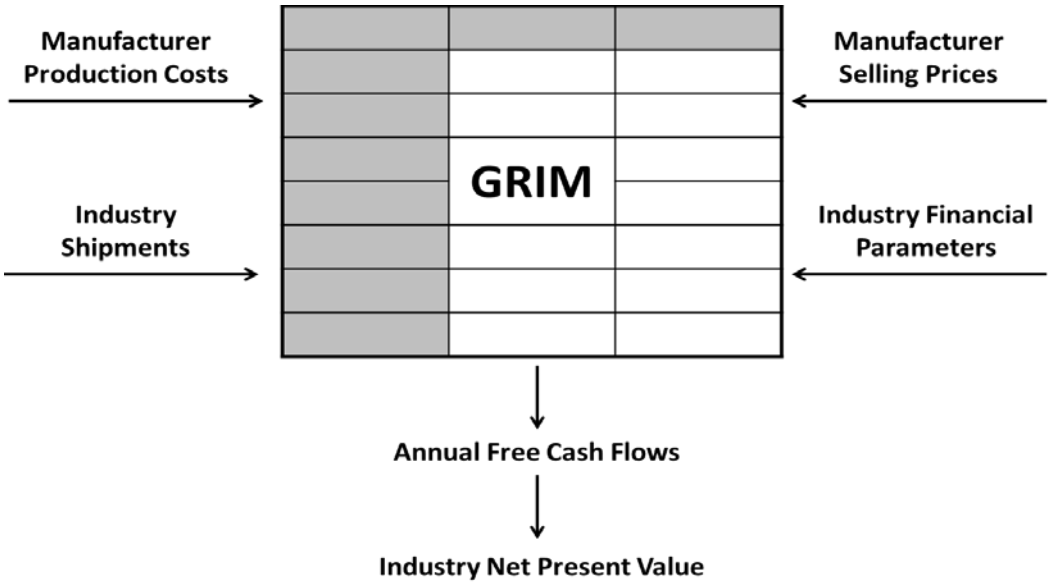

Figure 12-1 Using the GRIM to Calculate Cash Flow

The GRIM projects cash flows using standard accounting principles and compares changes in INPV between the no-new-standards case scenario and the standard-case scenario induced by amended energy conservation standards. The difference in INPV between the no-new-standards case and the standard case(s) represents the estimated financial impact of the amended energy conservation standard on manufacturers. Appendix 12A provides more technical details and user information for the GRIM.

12.3.2 Sources for GRIM Inputs

The GRIM uses several different sources for data inputs in determining industry cash flow. These sources include prior company profiles, census data, rulemaking financial metrics, the shipments model, the engineering analysis, and the manufacturer interviews.

12.3.2.1 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 freely 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 manufacturers that manufacture CWAF. Since these companies do not provide detailed information about their individual product lines, DOE used the financial information for the entire companies as its initial estimates of the financial

parameters in the GRIM analysis. These figures were later revised using feedback from interviews to be representative of manufacturing for each product grouping. 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

12.3.2.2 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.

12.3.2.3 Shipment Model

The GRIM used no-new-standards case and standards case shipment projections derived from DOE's shipments model in the NIA. Chapter 9 of the TSD describes the methodology and analytical model DOE used to forecast shipments.

12.3.2.4 Engineering Analysis

The engineering analysis establishes the relationship between manufacturer selling price (MSP) and energy efficiency for the equipment covered in this rulemaking. DOE conducted the engineering analysis using the reverse-engineering approach to estimate the costs of achieving various efficiency levels for gas-fired and oil-fired CWAF equipment. To develop cost estimates, DOE conducted a price analysis, based upon physical teardowns of selected units, cost estimates from publically available sources, and price quotes from manufacturers during interviews. DOE then developed a cost model to determine manufacturer production costs (MPCs). By applying derived manufacturer markups to the MPC and shipping costs, DOE calculated the MSP and constructed industry cost-efficiency curves. See Chapter 5 for a complete discussion of the engineering analysis.

12.3.2.5 Manufacturer Interviews

During the course of the MIA, DOE conducted interviews with a representative cross-section of manufacturers. DOE also interviewed manufacturers representing a significant portion of sales in every equipment class. During these discussions, DOE obtained information to determine and verify GRIM input assumptions in each industry. Key topics discussed during the interviews and reflected in the GRIM include:

- capital conversion costs (one-time investments in PPE);
- financial metrics;

- 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.

12.3.3 Financial Parameters

Table 12.2 provides financial parameters for give public companies engaged in manufacturing and selling CWAF equipment. The values listed are averages over a six-year period (2006 to 2011).

Table 12.2 Financial Parameters Used for GRIM Analysis (Based on 2006-2011 Company Financial Data)

Parameter	Industry-Weighted Average	Manufacturers				
		A	B	C	D	E
Tax Rate (% of Taxable Income)	26.3	28.0	15.4	33.8	41.3	17.8
Working Capital (% of Revenue)	6.0	6.8	2.9	10.0	13.7	13.5
SG&A (% of Revenue)	11.3	11.3	10.0	21.1	25.3	18.4
R&D (% of Revenues)	2.5	3.2	1.2	1.4	2.7	1.6
Depreciation (% of Revenues)	2.2	2.3	2.0	1.5	4.0	1.8
Capital Expenditures (% of Revenues)	2.2	1.8	2.4	1.8	4.4	1.1

While most of these companies also manufacture additional products beyond those covered by this rulemaking, DOE used these parameters as initial estimates. During interviews, manufacturers were asked to provide feedback for the parameters listed in Table 12.2. DOE adjusted the financial parameters using manufacturer feedback and market share information.

In addition to these parameters, DOE used financial information sourced from SEC filings for the five public manufacturers to determine an average manufacturer markup.

Table 12.3 Financial Parameters Used to Determine No-New-Standards Case Markup

	Manufacturer				
	A	B	C	D	E
Average Net Revenues (Million $)	3,262	2,085	200	650	710
Corporate Gross Margin	27	14	27	32	28
Markup	1.37	1.17	1.37	1.48	1.39

Table 12.3 lists the average net revenues, estimated corporate gross margin, and estimated manufacturer markup for the years 2006 to 2011 for the five manufacturers. The weighted average of the estimated manufacturer markup based on public filings by these five companies is 1.27. 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 adjusted its estimate manufacturer markup and applied the values listed in Table 12.4 for covered equipment.

Table 12.4 No-New-Standards Case Manufacturer Markups

Equipment	Markup
Gas-Fired CWAF	1.31
Oil-Fired CWAF	1.28

DOE used its standard methodology of determining initial GRIM financial input based on SEC filings and public documents. During interviews, manufacturers were asked to provide their own figures for the parameters listed in Table 12.3. Where applicable, DOE adjusted the parameters in the GRIM using manufacturer feedback and market share information. The adjusted financial parameters are shown in the table below.

Table 12.5 Financial Parameters used for CWAF GRIM

Parameter	Value
Tax Rate (% of Taxable Income)	26.3%
Working Capital (% of Revenue)	6.0%
SG&A (% of Revenue)	11.3%
R&D (% of Revenues)	2.5%
Depreciation (% of Revenues)	2.2%
Capital Expenditures (% of Revenues)	2.2%
Cost of Capital	8.9%

12.3.4 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 CWAF industry based on seven 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:

$$\textit{Cost of Equity} = \textit{Riskless Rate of Return} + \beta \times \textit{Risk Premium}$$

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 CWAF industry is 9.6 percent (Table 12.5).

Table 12.6 Cost of Equity Calculation

Parameter	Industry Weighted Average	A	B	C	D	E
(1) Average Beta	0.73	1.10	0.37	1.06	0.85	1.64
(2) Average Yield on 10-Year Bonds (1928-2012)	5.20					
(3) Market Risk Premium	6.01					
Cost of Equity (2)+[(1)*(3)]	9.6	11.8	7.4	11.6	10.3	15.1
Equity/Total Capital	68.6	70.6	71.2	50.4	63.1	70.9

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 seven 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 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 5.20 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.[c] DOE added these spreads to the estimated risk-free rate of 5.20 to determine the gross cost of debt for each company. It then calculated an industry weighted average gross cost of debt of 6.4 percent. Since 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 12.6 presents the derivation of the cost of debt and the capital structure of the industry (*i.e.*, the debt ratio (debt/total capital)).

Table 12.7 Cost of Debt Calculation

Parameter	Industry Weighted Average	A	B	C	D	E
S&P Bond Rating		AAA	AAA	AA	A+	A-
(1) Avg. Yield on 10-Yr Bonds (1928-2012)	5.20					
(2) Gross Cost of Debt	6.4	6.60	5.85	7.70	11.20	7.70
(3) Tax Rate	22.4	35.8	50.5	10.5	2.1	1.1
Net Cost of Debt (2) x [1-(3)]	4.9	4.8	4.9	5.1	6.6	6.3
Debt/Total Capital	31.4	29.4	28.8	49.6	36.9	29.1

Using public information for these five companies, the initial estimate for the industry's nominal WACC was approximately 5.04 percent. Subtracting an inflation rate of 3.09 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 straw-man GRIM is 5.83 percent. DOE also asked for feedback on the discount rate during manufacturer interviews. Based on this feedback, DOE used a discount rate of 8.9 percent in the GRIM.

12.3.5 Trial Standard Levels

DOE developed a number of efficiency levels for each type of equipment class. TSLs were then developed by selecting likely groupings of efficiency levels for all equipment types. Table 12.4 presents the TSLs used for energy efficiency analysis in the GRIM.

[c] For two of the seven manufacturers, S&P bond ratings were not available. In these cases, DOE estimated the companies' synthetic bond ratings based on their interest coverage ratio. The interest coverage ratio is calculated as the ratio of earnings before interest and taxes (EBIT) to current interest expenses, with the present value of operating leases reclassified as debt. The estimated synthetic bond ratings are based on a valuation method available through the NYU Stern School of Business and may be found at: http://www.stern.nyu.edu/~adamodar/pc/ratings.xls

Table 12.8 Trial Standard Levels for Energy Efficiency Analysis of CWAF Equipment

Equipment Class	No-New-Standards Case	TSL 1	Recommended TSL	TSL 3	TSL 4	TSL 5
Gas-fired CWAF ≥225,000 Btu/h	Baseline	EL 1	EL 1	EL 2	EL 2	EL 3
Oil-fired CWAF ≥225,000 Btu/h	Baseline	Baseline	EL 1	Baseline	EL 1	EL 2

12.3.6 NIA Shipments

The GRIM estimates manufacturer revenues based on total-unit-shipment forecasts and the distribution of these values by efficiency level. Changes in the efficiency mix at each standard level are a key driver of manufacturer finances. For this analysis, the GRIM applied the NIA shipments forecasts.

As part of the shipments analysis, DOE estimated the no-new-standards case shipment distribution by efficiency level for each equipment class. In the standards case, DOE determined efficiency distributions for cases in which a potential standard applies for 2019 and beyond. DOE assumed that all shipments in the no-new-standards case that did not meet the standard under consideration would meet the new standard in 2019 under a roll-up scenario. Consumers in the no-new-standards case who purchase units above the standard level are not affected as they are assumed to continue to purchase the same no-new-standards case unit in the standards case. See chapter 11 of the TSD for more information on the CWAF equipment standards-case shipments.

12.3.7 Production Costs

Changes in production costs affect revenues and gross profits. Products that are more efficient typically cost more to produce than baseline products (as shown in chapter 5 of the TSD). For the MIA, DOE used the MPCs derived in the engineering analysis.

Manufacturing a higher efficiency product is typically more expensive than manufacturing a baseline product. MPCs increase at higher efficiency levels due to the use of more raw material and more complex components, which are more costly than baseline components. These changes in MPC can affect the revenues, gross margins, and cash flow of the industry, making these product cost data key GRIM inputs for DOE's analysis.

To calculate baseline MSP, DOE followed a three-step process. First, DOE derived MPCs from the engineering and teardown analyses. Second, DOE applied a manufacturer markup, which varies with the markup scenario (discussed in detail in section 12.3.8), to the MPCs. The engineering analysis also provided shipping costs, which was included in the MSP calculation. DOE estimated MSPs for each efficiency level within each equipment class using the following formula:

$$\textit{Manufacturing Selling Price} = (\textit{Manufacturer Production Cost} \times \textit{Markup}) + \textit{Shipping Cost}$$

Table 12.5 through Table 12.6 show the production cost estimates used in the GRIM for each analyzed equipment class.

Table 12.9 Manufacturer Production Cost Breakdown ($2014) for Gas-fired CWAF

Efficiency Level	Materials (%)	Labor (%)	Depreciation (%)	Overhead (%)	MPC ($)	Shipping Cost ($)	Mark-up	MSP ($)
Baseline	85.4	10.8	2.9	1.0	359.78	0.00	1.31	471.31
EL 1	85.5	10.6	2.9	1.0	374.87	0.00	1.31	491.08
EL 2	85.7	10.4	2.9	1.0	619.48	0.00	1.31	811.52
EL 3	85.7	8.2	4.0	2.1	1,073.81	43.15	1.31	1,449.84

Table 12.10 Manufacturer Production Cost Breakdown ($2014) for Oil-fired CWAF

Efficiency Level	Materials (%)	Labor (%)	Depreciation (%)	Overhead (%)	MPC ($)	Shipping Cost ($)	Mark-up	MSP ($)
Baseline	76.8	12.1	5.0	6.1	1,613.43	69.43	1.28	2,134.62
EL 1	76.6	12.2	5.1	6.1	1,638.20	75.76	1.28	2,172.66
EL 2	79.4	11.3	3.8	5.4	2,304.24	83.31	1.28	3,032.74

DOE's rulemakings cover both CWAF and CUAC/CUHP. Gas-fired furnaces installed and CUAC/CUHP systems typically share the same cabinet. DOE accounted for the cabinet costs and overall shipping costs in the CUAC/CUHP engineering analysis rulemaking. As a result, the gas-fired furnace MSPs do not include the cost of cabinet or the shipping cost of the baseline system. However, DOE does include any incremental shipping costs that are a result of the amended standards for the gas-fired furnace equipment.

12.3.8 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 plant, property, and equipment to adapt or change existing production facilities in order to fabricate and assemble new product designs that comply with amended energy conservation standards. Product conversion costs are one-time investments in research, development, testing, marketing and other costs to make product designs comply with amended energy conservation standards.

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. Two methodologies were used to develop conversion cost estimates for High and Low scenarios: (1) a Top-Down approach using feedback from manufacturer interviews to gather data on the level of costs expected at each efficiency level, and (2) a Bottom-up approach using engineering analysis inputs derived from the product teardown analysis and engineering model

described in chapter 5 of the TSD to evaluate the investment required to design, manufacturer, and release equipment that meets a higher energy conservation standard.

12.3.8.1 Capital Conversion Costs

For estimating capital conversion costs, the Top-Down approach took available feedback from manufacturers and market share weighted the responses to arrive at an approximation representative of the industry as a whole. Responses from manufacturers with the greatest market share were given the greatest weight, while responses from manufacturers with the lowest market share were given the lowest weight. The Bottom-up approach took capital conversion costs from the engineering analysis on a per manufacturer basis to develop an industry wide cost estimate. This analysis include the expected equipment, tooling, conveyor and plant costs associated with CWAF production, as estimated by DOE based on product tear-down and manufacturers plant tours. The results of the two methodologies were integrated to create high and a low capital conversion cost scenarios. The scenarios are shown in Table 12.6 and Table 12.7.

Table 12.11 Industry Cumulative Capital Conversion Cost by Efficiency Level

Equipment Type	EL	Low Scenario ($M)	High Scenario ($M)
Gas-Fired CWAF	EL 1 - 81%	0.60	4.43
Gas-Fired CWAF	EL 2 - 82%	1.20	4.48
Gas-Fired CWAF	EL 3 - 92%	62.80	63.72
Oil-Fired CWAF	EL 1 - 82%	0.30	0.70
Oil-Fired CWAF	EL 2 - 92%	1.20	10.10

Table 12.12 Industry Cumulative Capital Conversion Costs by TSL

TSL	Low Scenario ($M)	High Scenario ($M)
1	0.6	4.4
Recommended	0.9	5.1
3	1.2	4.5
4	1.5	5.2
5	64.0	73.8

12.3.8.2 Production Conversion Costs

Product conversion costs for CWAFs are primarily driven by re-development and testing expenses. As the standard increases, increasing levels of re-development effort are required to meet the efficiency requirements as more equipment models require redesign. Additionally expected product conversion costs ramp up discontinuously where DOE expects condensing technology to be necessary to meet a revised energy conservation standard.

To estimate costs for product R&D, the Top-Down approach developed average costs per product platform based on feedback from manufacturers. Manufacturer feedback focused on the human capital investments, such as engineering and lab technician time necessary to update designs. In the Bottom-up approach, DOE used vendor quotes, industry product information, and

engineering cost model data to estimate the expenses associated with thermal efficiency testing, heat limit testing, product safety testing, reliability testing, and engineering effort. The results of the two methodologies were integrated to create high and a low product conversion cost scenarios. The scenarios are shown in Table 12.11 and Table 12.12

Table 12.13 Industry Cumulative Product Conversion Cost by Efficiency Level

Equipment Type	EL	Low Scenario ($M)	High Scenario ($M)
Gas-Fired CWAF	EL1 - 81%	6.31	11.25
Gas-Fired CWAF	EL2 - 82%	12.59	36.56
Gas-Fired CWAF	EL3 - 92%	16.89	72.13
Oil-Fired CWAF	EL1 - 82%	0.26	5.82
Oil-Fired CWAF	EL1 - 92%	1.38	11.48

Table 12.14 Industry Cumulative Product Conversion Costs by TSL

TSL	Low Scenario ($M)	High Scenario ($M)
1	6.3	11.3
Recommended	6.6	17.1
3	12.6	36.6
4	12.9	42.4
5	18.3	83.6

12.3.9 Markup Scenarios

DOE used multiple standards case markup scenarios to represent the uncertainty about the impacts of energy conservation standards on prices and profitability. In the no-new-standards case, DOE used the same markups applied in the engineering analysis. In the standards case, DOE modeled two markup scenarios to represent the uncertainty about the potential impacts on prices and profitability following the implementation of amended energy conservation standards: (1) a preservation of gross margin percentage scenario and (2) a preservation of operating profit scenario. These scenarios lead to different markups values that, when applied to the inputted MPCs, result in varying revenue and cash flow impacts.

12.3.9.1 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. As production costs increase with efficiency, this scenario implies that the absolute dollar markup will increase as well. DOE assumed the non-production cost markup—which includes SG&A expenses, R&D expenses, interest, and profit— to be 1.31 for Gas-fired and 1.28 for Oil-fired CWAF. This markup is consistent with the one DOE assumed in the engineering analysis. Manufacturers indicated that it is optimistic to assume that, as their MPCs increase in response to an energy conservation standard, they would be able to maintain the same gross margin percentage markup.

Therefore, DOE assumes that this scenario represents a high bound to industry profitability under an energy conservation standard.

12.3.9.2 Preservation of Operating Profit Scenario

During interviews, multiple manufacturers expressed concern that the higher production costs could harm profitability. Because of market characteristics, several manufacturers suggested that the additional costs of higher minimum efficiency products could not be fully passed through to customers. Incorporating this feedback, DOE modeled the preservation of operating profit scenario.

In the preservation of operating profit scenario, manufacturer markups are set so that operating profit one year after the compliance date of the new energy conservation standards is the same as in the no-new-standards case. Under this scenario, as the cost of production and the cost of sales go up, manufacturers are generally required to reduce their markups to a level that maintains no-new-standards case operating profit. The implicit assumption behind this markup scenario is that the industry can only maintain only its operating profit in absolute dollars after the standard. Operating margin in percentage terms is squeezed (reduced) between the no-new-standards case and standards case.

12.4 INDUSTRY FINANCIAL IMPACTS

Using the inputs and scenarios described in the previous sections, the GRIM estimated indicators of financial impacts on the CWAF industry. The following sections detail additional inputs and assumptions for CWAF equipment. The main results of the MIA are also reported in this section. The MIA consists of two key financial metrics: INPV and annual cash flows.

12.4.1 Introduction

The INPV measures the industry value and is used in the MIA to compare the economic impacts of different TSLs in the standards case. 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 2015 to 2048, the same analysis period used in the NIA (chapter 10 of the TSD). This timeframe models both the short-term impacts on the industry from the base year of the analysis until the compliance date (2015 until 2019) and a long-term assessment over the 30-year analysis period used in the NIA (2019 – 2048).

In the MIA, DOE compares the INPV of the no-new-standards case (no amended energy conservation standards) to that of each TSL in the standards case. The difference between the no-new-standards case and a standards-case INPV is an estimate of the economic impacts that implementing that particular TSL would have on the industry. The markup scenarios are described in greater detail in section.

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 1 or 2 years could strain the industry's access to capital. Consequently, the 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.

Annual cash flows are discounted to the base year, 2015. After the standards announcement date (*i.e.*, the publication date of the final rule), industry cash flows begin to decline as companies use their financial resources to prepare for the 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 every 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 standard 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 energy conservation standard. 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, higher inventory carrying to sell more expensive products, and higher accounts receivable for more expensive products. Depending on these two competing factors, cash flow can be either positively or negatively affected in the year the standard takes effect.

12.4.2 CWAF Industry Financial Impacts

The combination of markup scenarios and conversion costs scenarios results in 4 sets of results: (1) Preservation of Gross Margin Percentage and Low Conversion Costs scenario, (2) Preservation of Gross Margin Percentage and High Conversion Costs scenario, (3) Preservation of Operating Profit and Low Conversion Costs scenario, (4) Preservation of Operating Profit and High Conversion Costs scenario. DOE presents the highest and lowest INPV results from the combined scenarios to portray the range of potential impacts on the industry.

The low end of the range of impacts is the Preservation of Gross Margin Percentage and Low Conversion Costs scenario presented in Table 12.13. The middle of the range of impacts is the Preservation of Gross Margin and High Conversion Costs scenario in Table 12.14 and the Preservation of Gross Operating Profit and Low Conversion Costs scenario in Table 12.15. The high end of the range of impacts is the Preservation of Operating Profit and High Conversion Costs scenario Table 12.16.

Table 12.15 Preservation of Gross Margin Percentage / Low Conversion Cost Scenario: Changes in INPV

	Units	No-New-Standards Case	Trial Standard Level				
			1	Recommended	3	4	5
INPV	2014$ M	96.3	92.6	90.5	125.2	124.8	143.5
Change in INPV	2014$ M	-	(3.8)	(5.9)	28.8	28.4	47.2
	(%)	-	(3.9)	(6.1)	29.9	29.5	49.0

Table 12.16 Preservation of Gross Margin Percentage / High Conversion Cost Scenario: Changes in INPV

	Units	No-New-Standards Case	Trial Standard Level				
			1	Recommended	3	4	5
INPV	2014$ M	96.3	86.5	83.5	106.2	101.2	85.5
Change in INPV	2014$ M	-	(9.9)	(12.9)	9.9	4.8	(10.9)
	(%)	-	(10.3)	(13.4)	10.3	5.0	(11.3)

Table 12.17 Preservation of Operating Profit Scenario / Low Conversion Costs Scenario: Changes in INPV

	Units	No-New-Standards Case	Trial Standard Level				
			1	Recommended	3	4	5
INPV	2014$ M	96.3	91.9	90.0	84.4	84.0	39.3
Change in INPV	2014$ M	-	(4.5)	(6.4)	(11.9)	(12.3)	(57.1)
	(%)	-	(4.6)	(6.6)	(12.4)	(12.8)	(59.3)

Table 12.18 Preservation of Operating Profit Scenario / High Conversion Costs Scenario: Changes in INPV

	Units	No-New-Standards Case	Trial Standard Level				
			1	Recommended	3	4	5
INPV	2014$ M	96.3	85.8	83.0	65.5	60.4	(19.3)
Change in INPV	2014$ M	-	(10.6)	(13.4)	(30.9)	(35.9)	(115.7)
	(%)	-	(11.0)	(13.9)	(32.0)	(37.3)	(120.1)

12.5 IMPACTS ON SMALL BUSINESS MANUFACTURERS

Small manufacturers, niche equipment manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. As discussed in section IV.K, using average cost assumptions to develop an industry cash-flow estimate may be inadequate to assess differential impacts among manufacturer subgroups.

For CWAF, DOE identified and evaluated the impact of amended energy conservation standards on one subgroup: small manufacturers. The SBA defines a “small business” as having

750 employees or less for NAICS 333415, "Air-Conditioning and Warm Air Heating Equipment and Commercial and Industrial Refrigeration Equipment Manufacturing."

DOE conducted a market survey using available public information to identify small manufacturers of covered equipment. DOE's research involved industry trade association membership directories (including AHRI[d]) , individual company websites, and market research tools (e.g., Hoovers reports[e]) to create a list of companies that manufacture or sell the CWAF equipment covered by this rulemaking. DOE also asked industry representatives if they were aware of any other small manufacturers during manufacturer interviews. DOE reviewed publicly-available data and contacted companies on its list, as necessary, to determine whether they met the SBA's definition of a small business manufacturer of covered CWAF equipment. DOE screened out companies that do not offer equipment covered by this rulemaking, do not meet the definition of a "small business," or are foreign-owned and operated. DOE was able to determine that three manufacturers meet the SBA's definition of a "small business" and manufacture products covered by this rulemaking. Of the three, one offers gas-fired CWAF equipment and the other two offer oil-fired CWAF equipment.

The small gas-fired CWAF manufacturer accounts for 17 of the 254 gas-fired CWAF listing in the AHRI Directory. This small manufacturer offers product exclusively at baseline. At the proposed level of TSL 4, the manufacturer will need to update its equipment offerings to meet a standard at EL 3, or 82% TE. As with all manufacturers in the CWAF market, the small CWAF manufacturers will evaluate the upfront investments in redesigning against the likely revenue opportunities and value of these product lines to their business.

If existing cabinet designs can accommodate a larger heat exchanger and the small manufacturer is able to increase the efficiency of their product lines with relatively straight forward heat exchanger growth, they will likely stay in the market. However, depending on the business' level of focus the CWAF market, a larger redesign involving significant heat exchanger design changes, extensive cabinet re-tooling, or research efforts that require extensive and expensive testing could lead the smaller manufacturer to exit the market.

The first small oil-fired CWAF manufacturer accounts for 11 of the 16 oil-fired CWAF listing in the AHRI Directory. This small oil-fired furnace manufacturer produces some of the most efficient products on the market at 92% TE. The second small oil-fired manufacturer produces the most efficient non-condensing equipment on the market at 84% TE. These two small oil-fired manufacturers would unlikely be at a technological disadvantage relative to its competitors at the recommended TSL. It is possible the small manufacturers will have a competitive advantage given their technological lead and experience in the niche market of high efficiency commercial oil furnaces.

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[d] Based on listings in the AHRI directory accessed on August 2, 2013 (Available at: https://www.ahridirectory.org/ahridirectory/pages/home.aspx).
[e] Hoovers | Company Information | Industry Information | Lists, D&B (2013) (Available at: http://www.hoovers.com/) (Last accessed April 3, 2013).

12.6 OTHER IMPACTS

12.6.1 Direct Employment

To quantitatively assess the impacts of energy conservation standards on employment, DOE used the GRIM to estimate the domestic labor expenditures and number of employees in the no-new-standards case and at each TSL from 2015 through 2048. DOE used statistical data from the U.S. Census Bureau's 2013 ASM, the results of the engineering analysis, and interviews with manufacturers to determine the inputs necessary to calculate industry-wide 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 were then 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 U.S. Census Bureau's 2013 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 original equipment manufacturer (OEM) 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.

Using the GRIM, DOE estimates in the absence of new energy conservation standards, there would be 232 domestic production workers for CWAF equipment. The employment impact estimates shown in Table 12.17 below are a range of potential production employment levels that could exist following the compliance date of new energy conservation standards. Impacts shown are independent of the employment impacts from the broader U.S. economy, which are documented in the Employment Impact Analysis, chapter 13 of the TSD.

Table 12.19 Potential Changes in Total Number of Domestic Employment Workers in the CWAF Industry in 2019

		Trial Standard Level			
	1	Recommended	3	4	5
Total Number of Domestic Production Workers in 2019 (no production location change)	104 to 231	100 to 232	21 to 320	14 to 320	2 to 228
Change from No-New-Standards Case Estimate (232) of Domestic Production Workers in 2019	(128) to (1)	(132) to 0	(211) to 88	(218) to 88	(230) to (4)

*Numbers in parentheses represent negative values.

The upper bound of the range assumes that manufacturers would continue to produce the same scope of covered equipment within the United States, and assumes that domestic

production would not shift to countries with lower labor costs. At TSLs 1 and 2, the upper bound shows little change in employment from the baseline due to a constant level of production labor expenditure. The major costs and changes for increasing product efficiency at lower levels would be for capital, not labor.

The lower bound assumes that as the standard increases, manufacturers choose to retire sub-standard product lines rather than invest in manufacturing facility conversions and product redesigns. DOE assumes manufacturers take the lowest investment option and do not relocate any production facilities to lower-cost countries. In this scenario, there is a loss of employment because manufacturers consolidate and operate fewer production lines. Since this is intended to be a worst-case scenario for employment, there is no consideration given to the fact that there may be employment growth in higher-efficiency lines. Table 12.18 represents the percentage of products retired for each TSL to meet the adopted standard levels.

Table 12.20 Percentage of Products Retired to Meet Amended Standard Levels

TSL	Products Retired (%)
1	55.0
Recommended	57.0
3	91.0
4	94.0
5	99.0

DOE does not attempt to estimate the portion of production that occurs in other countries. Rather, the direct employment figure captures the maximum number of domestic production workers based on the available data and DOE's methodology. One noted constraint is that the production worker calculation methodology only takes into account the labor required for the most basic product that meets the equipment standard – it does not take into account additional features that manufacturers use to differentiate premium products, optional features and add-ons, or components in the cabinet that do not contribute to the cooling and heating functions. In the absence of amended energy conservation standards, DOE estimates that the industry would employ 232 domestic production workers in 2019, based on the following equation:

$$Annual\ Domestic\ Production\ Employment = \frac{ILE}{PWHW} \div PWAH$$

Where:

ILE = Industry Labor Expenditure at Baseline in 2019 × 100% US Labor percentage ($8.8M),
PWHW = Production Worker Hourly Wage ($19.07 / hour), and
PWAH = Production Worker Annual Hours (1,977 hours / year)

12.6.2 Production Capacity

According to the certain CWAF manufacturers interviewed, amended energy conservation standards could lead to decreased production capacity. Most manufacturers indicated there would be little to no production capacity decrease at 81% and 82% efficiency levels, but at 92% there would be significant capacity shortfall. This feedback is consistent with the engineering analysis, which found there would be sufficient capacity at current levels to meet slightly higher efficiency standards, but significant investment requirements for higher efficiency condensing furnace standards.

Except at the max-tech level, any necessary redesign of CWAF models would not fundamentally change the assembly of the equipment. Any bottlenecks are more likely to come from the redesign, testing, and certification process rather than from production capacity. To that end, some interviewed manufacturers expressed concern that the redesign of all products would require a significant portion of their engineering resources and there may not be enough in-house testing capacity to meet the amended standard.

12.6.3 Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of several impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. For the cumulative regulatory burden analysis, DOE looks at other significant product-specific regulations that could affect CWAF equipment manufacturers that will take effect 3 years before or after the compliance date of amended energy conservation standards for these products[f]. In addition to the amended energy conservation regulations on CWAF equipment, several other Federal regulations apply to these products and other equipment produced by the same manufacturers.

[f] The compliance date for CWAF equipment is in the year 2023.

Table 12.21 Compliance Dates and Expected Conversion Expenses of Federal Energy Conservation Standards Affecting CWAF Manufacturers

Federal Energy Conservation Standards	Approximate Compliance Date	Estimated Total Industry Conversion Expense
2007 Residential Furnaces & Boilers * 72 FR 65136 (Nov. 19, 2007)	2015	$88M (2006$)
2010 Gas Fired and Electric Storage Water Heaters 75 FR 20112 (April 16, 2010)	2015	$95.4M (2009$)
2011 Residential Furnaces ** 76 FR 37408 (June 27, 2011); 76 FR 67037 (Oct. 31, 2011)	2015	$2.5M (2009$)
2011 Residential Central Air Conditioners and Heat Pumps ** 76 FR 37408 (June 27, 2011); 76 FR 67037 (Oct. 31, 2011)	2015	$ 26.0M (2009$)
Walk-in Coolers and Freezers 79 FR 32049 (June 3, 2014)	2017	$35.2M (2012$)
Commercial and Industrial Fans and Blowers †	2018	TBD
Commercial Unitary Air Conditioners and Heat Pumps†	2019	$226.4 (2013$)
Furnace Fans 79 FR 38129 (July 3, 2014)	2019	$40.6M (2012$)
Packaged Terminal Air Conditioners and Heat Pumps 80 FR 43162 (July 21, 2015); 80 FR 56894 (Sept. 21, 2015)	2019	$7.6M (2013$)
Residential Boilers †	2019	TBD
Commercial Packaged Boilers †	2019	TBD
Single Package Vertical Units 80 FR 57438 (Sept. 23, 2015)	2019	$9.2M (2014$)
Residential Non-Weatherized Gas Furnaces †	2019	TBD
Residential Central Air Conditioners and Heat Pumps †	2021	TBD
Residential Water Heaters †	2021	TBD

* Conversion expenses for manufacturers of oil-fired furnaces and for manufacturers of gas-fired and oil-fired boilers associated with the November 2007 final rule for residential furnaces and boilers are excluded from this figure. With regard to oil-fired furnaces, the 2011 direct final rule for residential furnaces sets a higher standard and earlier compliance date for oil-fired furnaces than the 2007 final rule. As a result, manufacturers will be required design to the 2011 direct final rule standard. The conversion costs associated with the 2011 direct final rule are listed separately in this table. With regard to gas-fired and oil-fired boilers, 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.

**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 final rule for this energy conservation standard has not been published. For energy conservation standards which have published a NOPR, DOE lists the compliance date and conversion costs for the proposed standard level. However, standard level and analytic results are not finalized until the publication of the final rule. For energy

conservation standards which have not yet reached the NOPR publication phase of the rulemaking, information is not yet available.

12.7 CONCLUSION

The following section summarizes the impacts for the scenarios DOE believes are most likely to capture the range of impacts on CWAF equipment manufacturers as a result of energy conservation standards. DOE also notes that while these scenarios bound the range of most plausible impacts on manufacturers, there potentially could be circumstances that cause manufacturers to experience impacts outside of this range.

As noted in section 12.3 (Sources for GRIM Inputs), the MIA uses the Engineering Analysis' manufacturer production costs and the Shipments Analysis' sales forecasts as inputs. Two key trends in these inputs help drive the MIA results. First, the increase in efficiency at TSLs below max-tech can be accomplished with very little incremental production cost. This is highlighted in the engineering results, as shown in the table below:

Incremental Manufacturing Cost Increases[g]

Equipment Type	Baseline	EL1	EL2	EL3
Gas-fired CWAF	-	$15.09	$244.61	$454.33
Oil-fired CWAF	-	$24.77	$666.04	n/a

At levels below TSL 2, gas-fired equipment MPCs increase by 4 percent at most and oil-fired MPC increase by 2 percent at most. Furthermore, at levels below TSL 2, total industry shipments over the analysis period remain the same. Since DOE's analysis indicates there are no significant changes to variable production costs and no significant changes in total shipments at TSL 2, today's proposed standard, manufacturer markups are also unlikely to vary significantly at those TSLs and will have limited impact on the change in industry value between the no-new-standards case and standards cases.

However, conversion costs provided by manufacturers in interviews were quite high relative to industry value. As a result, conversion costs have a significant impact on industry value. In particular, product conversion costs and time requirements were a concern for the industry. Manufacturer input during interviews indicated higher product conversion costs than initially expected by DOE. As a result, the Department modeled a sensitivity related to conversion costs. DOE applied two different methodologies to estimate conversion costs: Top-down and Bottom-up approach, as described in section 12.3.8 (Conversion Costs).

In its analysis, DOE ran 4 scenarios based on combinations from 2 markup scenarios and 2 conversion cost scenarios. The complete results are shown in section 12.4.2 (CWAF Industry Financial Impacts). The results presented below represent the upper-bound and lower-bound from those scenarios.

[g] Data pulled from Appendix 12B of the CWAF final rule TSD.

TSL 1 represents EL 1 (81%) for gas-fired CWAF and baseline (81%) for oil-fired CWAF. At this level, DOE estimates 55 percent of the industry platforms would require redesign at a total industry conversion cost of $6.9 million to $15.7 million. DOE estimates impacts on INPV for CWAF manufacturers to range from a change in INPV of -11.0 percent to -3.9 percent, or $10.6 million to -$3.8 million. At this potential standard level, industry free cash flow is estimated to decrease by as much as 72.3 percent to $2.2 million, compared to the no-new-standards case value of $7.3 million in 2018, the year before the compliance date (2019).

The recommended TSL represents EL 1 (81% for gas-fired and 82% for oil-fired) across all equipment classes. At this level, DOE estimates 57.0 percent of the industry platforms would require redesign at a total industry conversion cost of $7.5 million to $22.2 million. DOE estimates impacts on INPV for CWAF manufacturers to range from a change in INPV of -13.9 percent to -6.1 percent, or a change of -$13.4 million to -$5.9 million. At this potential standard level, industry free cash flow is estimated to decrease by as much as 119.3 percent to -$1.5 million, compared to the no-new-standards case value of $7.3 million in 2022, the year before the compliance date (2023).

Much of this drop in free cash flow at the recommended TSL is due to conversion cost expenses manufacturers must make before the compliance year. However, industry noted that the alignment of the commercial unitary air conditioner and heat pump and CWAF effective dates would allow for coordination of redesign and testing expenses. If this occurs, there would be a reduction in the total conversion costs associated with today's direct final rule. These synergies that result from the alignment of the commercial unitary air conditioner and heat pump and CWF effective dates would result in INPV impacts and free cash flow impacts that are less severe than forecasted by the GRIM model.

TSL 3 represents EL 2 (82%) for gas-fired CWAF and baseline (81%) for oil-fired CWAF. At this level, DOE estimates 91 percent of the industry platforms would require redesign at a total industry conversion cost of $13.8 million to $41.0 million DOE estimates impacts on INPV for CWAF manufacturers to range from a change in INPV of -32.0 percent to 29.9 percent, or -$30.9 million to $28.4 million. At this potential standard level, industry free cash flow is estimated to decrease by as much as 196.5 percent to -$7.5 million, compared to the no-new-standards case value of $7.3 million in 2018. A key indicator of impact on the industry is industry free cash flow. The negative free cash flow indicates that players in the industry would need to access cash reserves or borrow money from capital markets to cover conversion costs.

TSL 4 represents EL 2 (82%) for gas-fired CWAF and EL 1 (82%) for oil-fired CWAF. At this level, DOE estimates 94 percent of the industry platforms would require redesign at a total industry conversion cost of $14.4 million to $47.6 million. DOE estimates impacts on INPV for CWAF manufacturers to range from a change in INPV of -37.3 percent to 29.5 percent, or -$35.9 million to $28.4 million. At this potential standard level, industry free cash flow is estimated to decrease by as much as 233.4 percent to -$10.4 million, compared to the no-new-standards case value of $7.3 million in 2018. The negative free cash flow indicates that players in the industry would need to access cash reserves or borrow money from capital markets to cover conversion costs.

TSL 5 represents max-tech across all equipment classes (i.e., EL 3 (92%) for gas-fired CWAF and EL 2 (92%) for oil-fired CWAF). At this level, DOE estimates 99 percent of the industry platforms would require redesign at a total industry conversion cost of $82.3 million to $157.4 million. DOE estimates impacts on INPV for CWAF manufacturers to range from a change in INPV of -120.1 percent to 49.0 percent, or -$115.7 million to $47.2 million. At this potential standard level, industry free cash flow is estimated to decrease by as much as 861.3 percent to -$59.5 million relative to the no-new-standards case value of $7.3 million in 2018.

At max-tech, the vast majority of the industry does not offer condensing commercial furnaces today and would need to develop condensing technology for commercial applications. Implementing a condensing commercial furnace would likely have design implications for the cooling side of the HVAC product and for the chassis that houses both the cooling and heating components.

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APPENDIX 12A MANUFACTURER IMPACT ANALYSIS INTERVIEW GUIDE

TABLE OF CONTENTS

12A.1..MANUFACTURER IMPACT ANALYSIS INTERVIEW GUIDE FOR COMMERCIAL WARM AIR FURNACES ..... …….12A-1

12A.1 MANUFACTURER IMPACT ANALYSIS INTERVIEW GUIDE FOR COMMERCIAL WARM AIR FURNACES

Introduction

As part of the rulemaking process for amended energy conservation standards for Commercial Warm Air Furnaces (CWAF), the Department of Energy (DOE) conducts 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 amended 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 CWAF 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 questions intended to solicit more qualitative comments. Topics covered will include:

1) **Key Issues**
2) **Characteristics and Technologies**
3) **Conversion Costs**
4) **Distribution Channels**
5) **Market Share / Product Mix / Consolidation**
6) **Cumulative Regulatory Burden**
7) **Financial Parameters**
8) **Impacts on Small Businesses**
9) **Other Issues**

The U.S. Department of Energy (DOE) is conducting a rulemaking to review the energy conservation standards for commercial warm air furnaces. This rulemaking was initiated with the publication of a request for information (RFI) (available at: http://www.regulations.gov/#!docketDetail;D=EERE-2013-BT-STD-0021-0001) which provides background on the history of the commercial warm air furnace standards, statutory authority, rulemaking phases, and analysis conducted at each phase.

Covered equipment for this rulemaking include:

Table 1.1 Equipment Classes for Commercial Warm Air Furnaces under Consideration for the Rulemaking

Commercial Warm Air Furnace Type	Characteristics
Gas-fired Warm Air Furnace	Gas-fired warm air furnace; Input capacity greater than 225,000 Btu/h
Oil-fired Warm Air Furnace	Oil-fired warm air furnace; Input capacity greater than 225,000 Btu/h

1 KEY ISSUES

DOE is interested in understanding the impact of amended energy conservation standards on manufacturers. This section provides an opportunity for manufacturers to identify high priority issues that DOE should take into consideration.

1.1 In general, what are the key concerns for your company regarding the commercial warm air furnace rulemaking? Are any of these concerns specific to a particular equipment class?

1.2 How would amended energy conservation standards affect your ability to compete in the marketplace?

2 COMMERCIAL WARM AIR FURNACE CHARACTERISTICS AND TECHNOLOGIES

2.1 DOE has preliminarily identified the following design features as those that impact energy use and are generally incorporated into "baseline" (i.e., 80% thermal efficiency for gas furnaces and 81% thermal efficiency for oil furnaces) commercial furnaces. Please provide comment on the listed characteristics, as well as any other characteristics that are not listed but are included in baseline models.

Table 2.1 Baseline Design Features by Equipment Class

Equipment Class	Characteristics	Manufacturer Feedback
Gas-Fired	• **Induced draft PSC fan motor** • **Multiple In-shot steel burners** • **Direct spark igniter or hot surface igniter** • **Aluminized steel (tubular) heat exchanger (HX) coated for corrosion resistance** • **Dimples on flue side tubes**	
Oil-Fired	• **Induced draft** • **Single-stage burner** • **Electronic ignition** • **Steel heat exchanger** • **PSC belt-drive blower motor**	

2.2 Table 2.2 below provides technology options identified by DOE that can increase thermal efficiency. Please comment on any information regarding the technologies used to achieve higher thermal efficiencies for your equipment, including any technologies that are not listed.

Table 2.2 Technology Options for Achieving Higher Thermal Efficiencies for Commercial Warm Air Furnaces

Design Features	Impact on Thermal Efficiency	Manufacturing Cost
Technologies Needed to Achieve 81-82% Thermal Efficiency		
Increased HX surface area		
Two-stage or modulating burners		
Improved flue side HX enhancements		
Larger combustion inducer (to overcome the pressure drop of the increased HX area)*		
logies Needed to Achieve 90% Thermal Efficiency (Condensing)		
Secondary HX (stainless steel or aluminized steel)		
Upgraded housing for combustion blowers (to overcome the pressure drop of the increased HX area)*		
Stainless steel impellers		

Condensate heater (to prevent condensate freezing)*		
Draining condensate into interior space (to prevent condensate freezing)*		

* Note: these technologies do not directly lead to a higher thermal efficiency, but would allow the implementation of other technologies that would cause the furnace to operate more efficiently.

2.3 Can you provide data or comment on thermal efficiency improvements attributable to increasing the heat exchanger area? How does this differ between aluminized steel heat exchangers and stainless steel heat exchangers?

2.4 Does the thickness of the heat exchanger tube affect thermal efficiency? If so, what is the range of thickness from 80% to 90% thermal efficiencies? Does thickness of the heat exchanger tube vary based on input capacity?

2.5 Does your company currently offer a commercial furnace that utilizes condensing technology? If not, have you considered using this technology option? What are the primary drivers in the decision of whether or not to offer equipment with this technology option?

2.6 How do design options vary by capacity? Are there technical or other factors that make the cost of implementing a given technology higher for some capacities than for others?

2.7 What are your primary constraints when designing more efficient products (e.g. safety issues, cost, comfort, etc.)?

2.8 As mentioned above, DOE found that baseline equipment typically uses 2-stage burners. Do you offer commercial furnaces with single stage burners? Also, what factors cause you to implement a multi-stage burner or modulating burner design?

2.9 For oil-fired commercial furnaces, do changes in the burner (e.g., different models and/or manufacturers) affect thermal efficiency? What causes these changes in performance?

2.10 DOE is aware that oil burners are shipped with several nozzles, allowing the installer to determine fuel input rating in the field. Does varying the firing rate (i.e., interchanging these nozzles) affect thermal efficiency? If so, by how much?

2.11 How does the electricity consumption of furnace components (i.e. fans, ignition systems, power burners) change with respect to thermal efficiency? Can you quantify the differences in the electricity consumption of these components between furnaces with different thermal efficiencies?

3 CONVERSION COSTS

3.1 What levels of capital expenditure and equipment investment would be necessitated by higher standard levels? Please describe what those investments entail and provide a dollar estimate.

3.2 What level of product conversion costs (one-time product investments – such as the investment in R&D, product redesign, testing, and revised marketing materials) would you anticipate at higher standard levels? Please describe what they are and provide your best estimate of their respective magnitudes.

3.3 How would the imposition of new energy conservation standards affect production capacity at your domestic production facilities? Would a new standard result in stranded capital assets?

3.4 If DOE were to adopt a thermal efficiency standard high enough to effectively require the use of condensing technology, would you be able to convert your manufacturing lines to meet this standard with three years of lead time from when the standard is announced and when the standard goes into effect?

4 DISTRIBUTION CHANNELS

4.1 What distribution channels are used from the manufacturer to the end user?

4.2 What is the share of product (by efficiency and/or equipment class) going through each distribution channel?

5 MARKET SHARE, PRODUCT MIX, AND INDUSTRY CONSOLIDATION

5.1 What is your company's approximate market share of commercial furnace sales as a whole?

5.2 What is your company's approximate market share in each of the equipment classes?

5.3 Who are your primary competitors? Can you provide an estimate of their market shares in each equipment class?

5.4 What is the approximate percentage of your company's shipments in each equipment class?

5.5 What is the approximate percentage of your company's shipments at each efficiency level (80%, 81%, 82%, & ≥ 90% thermal efficiency) for both gas and oil fired equipment?

5.6 How would your company's equipment mix and marketing strategy change with changes in the efficiency standard?

5.7 How many of the packaged rooftop units include a furnace?

5.8 Would you expect your market share to change if DOE were to amend the thermal efficiency standard?

5.9 Could amended thermal efficiency standards disproportionately advance or harm the competitive position of some firms? If so, why?

5.10 Could amended standards result in disproportionate economics or performance penalties for particular consumer/user subgroups?

5.11 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?

5.12 In the absence of new standards, how would you expect the fractions of equipment shipments, related to the efficiency levels listed in 5.5, to change over the next five and ten years?

5.13 Would amended standards affect the level of industry consolidation?

5.14 How would you expect shipments to change for the industry as a whole as a function of higher standards and why?

5.15 What percentage of domestic sales are products imported from outside the United States (e.g., Canada, Mexico, etc.)?

5.16 Absent amended standards, are commercial furnace production facilities being relocated to foreign countries?

6 CUMULATIVE REGULATORY BURDEN

6.1 Are there recent or impending regulations on commercial furnaces or other equipment you manufacture that would impose a cumulative burden on the industry in conjunction with revised efficiency standards? If so, what is the total expected impact of those other regulations?

7 FINANCIAL METRICS

7.1 **Please compare your company's equipment financial parameters to the estimated values tabulated below:**

GRIM Input	Definition	Estimated Value	Your Actual
Income Tax Rate	Corporate effective income tax paid (percentage of earnings before taxes, EBT)	23%	
Discount Rate	Weighted average cost of capital (inflation-adjusted weighted average of corporate cost of debt and return on equity)	5%	
Working Capital	Current assets less current liabilities (percentage of revenues)	5.4%	
SG&A	Selling, general, and administrative expenses (percentage of revenues)	12.0%	
R&D	Research and development expenses (percentage of revenues)	2.0%	
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)	2.2%	
Cost of Goods Sold	Includes material, labor, overhead, and depreciation (percentage of revenues)	79.2%	

7.2 **DOE defines markup as the ratio of manufacturer selling price (MSP) to manufacturer production cost (MPC). As an average across all product classes, DOE estimated a markup of 1.27. Is this markup representative of your business? If not, please provide your markups below:**

Commercial Furnace Type	Estimated Markup	Your Actual
Gas-fired Warm Air Furnace	1.27	
Oil-fired Warm Air Furnace	1.27	

7.3 **Do markups vary between gas-fired and oil-fired products?**

7.4 **Do markups increase for high efficiency products?**

7.5 **What other product characteristics or features affect markup?**

8 SMALL BUSINESS ISSUES

8.1 **The Small Business Association (SBA) denotes a small business in the commercial furnace industry as having less than 750 employees. By this definition, is your company considered a small business?**

8.2 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.

8.3 Below is an initial list of small manufacturers of commercial furnaces. Please provide feedback on the correctness of this list. Information on additional small manufacturers would be greatly appreciated.

- **Adams Manufacturing**
- **Hastings HVAC, Inc**
- **Heat Controller, Inc**

9 OTHER ISSUES

9.1 Do you have an estimate of the commercial furnace lifetime? Typically how long do your customers use your furnaces before replacing them? Is this affected by the air conditioner side of packaged systems? Is lifetime related to efficiency of the furnace?

9.2 How long are the warranties offered for your commercial furnaces and what is covered?

9.3 What is the typical or anticipated cost of testing to demonstrate DOE compliance with the current test procedure? What testing, in addition to testing to show DOE compliance for regulated products, do all or most equipment typically undergo? How much do these additional tests cost? What is the primary cost associated with testing, *i.e.* labor, equipment, time? Are the tests conducted in-house or at a third-party lab?

9.4 Based on your experience with efficiency testing/rating, what have you found to be the margin for error with the current DOE test procedure for commercial furnaces?

9.5 Please describe how annual maintenance/repair costs of commercial furnaces change as a result of improved thermal efficiency. Which design changes could result in different repair/maintenance costs? What are the maintenance requirements at each efficiency level? Could you list any major reparable components?

9.6 Are there any patent, technology, other issues that would prevent your company or competitors from implementing higher-efficiency designs?

9.7 Are shipping costs relatively similar across all efficiency levels or do higher efficiency units cost more to ship? Please comment on this as it relates to your equipment lines.

9.8 Generally, how much does it cost to ship a full trailer of equipment to the next member of the distribution chain? How are trailers generally loaded? That is, are they always sent out full, or sometimes partially empty?

9.9 Generally, who pays for the cost of shipping your equipment to the next member of the distribution chain? Is it included in the purchase price, does your company provide shipping, does the purchaser arrange shipping, or is another arrangement used?

9.10 If DOE were to adopt a condensing level as a Federal Standard, would there be concerns with training and educating the installers/servicers on how to properly service and install condensing equipment within the three year timeframe until the standard becomes effective?

9.11 The secondary heat exchanger in a condensing furnace will cause increased pressure drop which leads to more power consumption by the air circulation fan to overcome that pressure drop. Can you comment on the magnitude of the increased pressure drop and associated increase in fan power consumption for a condensing commercial furnace design?

9.12 The DOE test procedure specifies that efficiency testing be conducted at an external static pressure of 0.25 in. H2O for equipment 225,000 – 281,000 Btu/h and 0.3 in. H2O for equipment greater than 281,000 Btu/h. How much external static pressure is typically encountered in the field?

9.13 DOE acknowledges that the highest non-condensing thermal efficiency level for gas-fired units currently on the market is 82%. DOE is also aware that 82% efficient furnaces may have issues with regards to condensate management and corrosion in certain installations. What are the significant challenges and issues with dealing with corrosion at the 82% thermal efficiency level? What (if any) special strategies do you use to minimize the occurrence of or impact of corrosive condensate in commercial furnaces at 82% thermal efficiency? Do these issues and challenges apply to all locations and climate zones in the US or only to certain installations?

APPENDIX 12B. GOVERNMENT REGULATORY IMPACT MODEL (GRIM) OVERVIEW

TABLE OF CONTENTS

12B.1 Introduction and Purpose 1
12B.2 Model Description.....1

LIST OF TABLES

Table 12B.2.1 Detailed Cash Flow Example.....4

APPENDIX 12B. GOVERNMENT REGULATORY IMPACT MODEL (GRIM) OVERVIEW

12B.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(s) 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 no-new-standards case) and under different trial standard levels (*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.

12B.2 MODEL DESCRIPTION

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. Below are definitions of listed items on the printout of the output sheet of the GRIM.

(1) ***Unit Sales:*** Total annual shipments for the industry were obtained from the National Impact Analysis Spreadsheet.

(2) ***Revenues:*** Annual revenues – computed by multiplying products' unit prices at each efficiency level by the appropriate manufacturer markup.

(3) ***Labor:*** The portion of cost of goods sold (COGS) that includes direct labor, commissions, dismissal pay, bonuses, vacation, sick leave, social security contributions, fringe, and assembly labor up-time.

(4) ***Material:*** The portion of COGS that includes materials.

(5) ***Overhead:*** The portion of COGS that includes indirect labor, indirect material, energy use, maintenance, depreciation, property taxes, and insurance related to assets. While included in overhead, the depreciation is shown as a separate line item.

(6) ***Depreciation:*** The portion of overhead that includes an allowance for the total amount of fixed assets used to produce that one unit. Annual depreciation is computed as a percentage of ***COGS.*** While included in overhead, the depreciation is shown as a separate line item.

(7) ***Stranded Assets:*** In the year the standard becomes effective, a one-time write-off of stranded assets is accounted for.

(8) ***Standard SG&A:*** Selling, general, and administrative costs are computed as a percentage of ***Revenues (2)***.

(9) ***R&D:*** GRIM separately accounts for ordinary research and development (R&D) as a percentage of ***Revenues (2)***.

(10) ***Product Conversion Costs:*** Product conversion costs are one-time investments in research, development, testing, marketing, and other costs focused on making products designs comply with the new energy conservation standard. The GRIM allocates these costs over the period between the standard's announcement and compliance dates.

(11) ***Earnings Before Interest and Taxes (EBIT):*** Includes profits before deductions for interest paid and taxes.

(12) ***EBIT as a Percentage of Sales (EBIT/Revenues):*** GRIM calculates EBIT as a percentage of sales to compare with the industry's average reported in financial statements.

(13) ***Taxes:*** Taxes on ***EBIT (11)*** are calculated by multiplying the tax rate contained in Major Assumptions by ***EBIT (11)***.

(14) ***Net Operating Profits After Taxes (NOPAT):*** Computed by subtracting ***Cost of Goods Sold ((3) to (6))***, ***SG&A (8)***, ***R&D (9)***, ***Product Conversion Costs (10)***, and ***Taxes (13)*** from ***Revenues (2)***.

(15) ***NOPAT repeated***: NOPAT is repeated in the Statement of Cash Flows.

(16) ***Depreciation repeated***: Depreciation and Stranded Assets are added back in the Statement of Cash Flows because they are non-cash expenses.

(17) ***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.

(18) ***Cash Flow From Operations***: Calculated by taking ***NOPAT (15)***, adding back non-cash items such as a ***Depreciation (16)***, and subtracting the ***Change in Working Capital (17)***.

(19) ***Ordinary Capital Expenditures:*** Ordinary investments in property, plant, and equipment to maintain and replace existing production assets, computed as a percentage of ***Revenues (2)***.

(20) ***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 the new regulation. The GRIM allocates these costs over the period between the standard's announcement and compliance dates.

(21) ***Capital Investment:*** Total investments in property, plant, and equipment are computed by adding ***Ordinary Capital Expenditures (19)*** and ***Capital Conversion Costs (20)***.

(22) ***Free Cash Flow:*** Annual cash flow from operations and investments; computed by subtracting ***Capital Investment (21)*** from ***Cash Flow from Operations (18)***.

(23) ***Terminal Value:*** Estimate of the continuing value of the industry after the analysis period. Computed by growing the Free Cash Flow at the beginning of 2048 at a constant rate in perpetuity.

(24) ***Present Value Factor:*** Factor used to calculate an estimate of the present value of an amount to be received in the future.

(25) ***Discounted Cash Flow: Free Cash Flows (22)*** multiplied by the ***Present Value Factor (24)***. For the end of 2048, the discounted cash flow includes the discounted ***Terminal Value (23)***.

(26) ***Industry Value thru the end of 2048:*** The sum of ***Discounted Cash Flows (25)***.

Table 12B.2.1 Detailed Cash Flow Example

No STDs Case DCF | **Navigation**

Industry Income Statement (in 2014$ millions)	2014	2015 (Ancmt Yr)	2016	2017	2018	2019 (Std Yr)	2020	2021	2022
Revenues	$ 107.6	$ 106.3	$ 107.4	$ 108.3	$ 109.7	$ 108.3	$ 108.6	$ 108.9	$ 108.9
Shipping Cost	0.416	0.401	0.406	0.409	0.414	0.144	0.146	0.148	0.149
Shipments	0.209	0.209	0.214	0.218	0.223	0.229	0.232	0.235	0.238
Revenue - Shipping	107.201	105.907	107.039	107.878	109.269	108.156	108.432	108.704	108.775
- Materials	$ 69.8	$ 69.0	$ 69.7	$ 70.3	$ 71.2	$ 70.6	$ 70.7	$ 70.9	$ 71.0
- Labor	$ 8.7	$ 8.6	$ 8.7	$ 8.8	$ 8.9	$ 8.8	$ 8.8	$ 8.8	$ 8.8
- Depreciation	$ 2.5	$ 2.4	$ 2.5	$ 2.5	$ 2.5	$ 2.4	$ 2.4	$ 2.4	$ 2.4
- Overhead	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 0.8	$ 0.8	$ 0.9	$ 0.9
- Standard SG&A	$ 12.1	$ 12.0	$ 12.1	$ 12.2	$ 12.3	$ 12.2	$ 12.3	$ 12.3	$ 12.3
- R&D	$ 2.7	$ 2.6	$ 2.7	$ 2.7	$ 2.7	$ 2.7	$ 2.7	$ 2.7	$ 2.7
- Product Conversion Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
- Stranded Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Earnings Before Interest and Taxes (EBIT)	$ 10.4	$ 10.3	$ 10.4	$ 10.4	$ 10.6	$ 10.6	$ 10.7	$ 10.7	$ 10.7
Per Unit EBIT *($/unit)*	$ 49.58	$ 49.02	$ 48.52	$ 47.98	$ 47.48	$ 46.52	$ 46.03	$ 45.54	$ 45.06
EBIT/Revenues (%)	*9.6%*	*9.6%*	*9.6%*	*9.6%*	*9.6%*	*9.8%*	*9.8%*	*9.8%*	*9.8%*
- Taxes	$ 2.7	$ 2.7	$ 2.7	$ 2.7	$ 2.8	$ 2.8	$ 2.8	$ 2.8	$ 2.8
Net Operating Profit after Taxes (NOPAT)	**$ 7.6**	**$ 7.6**	**$ 7.6**	**$ 7.7**	**$ 7.8**	**$ 7.8**	**$ 7.9**	**$ 7.9**	**$ 7.9**
Cash Flow Statement									
NOPAT	$ 7.6	$ 7.6	$ 7.6	$ 7.7	$ 7.8	$ 7.8	$ 7.9	$ 7.9	$ 7.9
+ Depreciation	$ 2.5	$ 2.4	$ 2.5	$ 2.5	$ 2.5	$ 2.4	$ 2.4	$ 2.4	$ 2.4
+ Loss on Disposal of Stranded Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
- Change in Working Capital	$ -	$ (0.1)	$ 0.1	$ 0.1	$ 0.1	$ (0.1)	$ 0.0	$ 0.0	$ 0.0
Cash Flows from Operations	$ 10.1	$ 10.1	$ 10.0	$ 10.1	$ 10.2	$ 10.3	$ 10.3	$ 10.3	$ 10.3
- Ordinary Capital Expenditures	$ 2.4	$ 2.3	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4
- Capital Conversion Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Free Cash Flow	**$ 7.7**	**$ 7.7**	**$ 7.7**	**$ 7.7**	**$ 7.8**	**$ 8.0**	**$ 7.9**	**$ 7.9**	**$ 7.9**
Discounted Cash Flow									
Free Cash Flow	$ 7.7	$ 7.7	$ 7.7	$ 7.7	$ 7.8	$ 8.0	$ 7.9	$ 7.9	$ 7.9
Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Present Value Factor	*0.000*	*1.000*	*0.918*	*0.843*	*0.774*	*0.711*	*0.653*	*0.600*	*0.551*
Discounted Cash Flow	**$ -**	**$ 7.7**	**$ 7.0**	**$ 6.5**	**$ 6.1**	**$ 5.7**	**$ 5.1**	**$ 4.7**	**$ 4.4**
INPV at Baseline $ 96.3									
Net PPE	$ 16.1	$ 16.0	$ 15.9	$ 15.8	$ 15.7	$ 15.7	$ 15.7	$ 15.6	$ 15.6
Net PPE as % of Sales	15.0%	15.1%	14.8%	14.6%	14.4%	14.5%	14.4%	14.4%	14.3%
Net Working Capital	$ 6.5	$ 6.4	$ 6.4	$ 6.5	$ 6.6	$ 6.5	$ 6.5	$ 6.5	$ 6.5
Return on Invested Capital (ROIC)	33.84%	33.71%	34.11%	34.45%	34.92%	35.32%	35.44%	35.56%	35.63%
Weighted Average Cost of Capital (WACC)	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
Return on Sales (EBIT/Sales)	9.64%	9.65%	9.65%	9.65%	9.65%	9.83%	9.83%	9.83%	9.83%

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

CHAPTER 13. EMISSIONS IMPACT ANALYSIS

TABLE OF CONTENTS

13.1 INTRODUCTION 13-1
13.2 AIR QUALITY REGULATIONS AND EMISSIONS IMPACTS 13-2
13.3 EMISSIONS IMPACT RESULTS 13-3

LIST OF TABLES

Table 13.3.1 Cumulative Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces* 13-4

LIST OF FIGURES

Figure 13.3.1 Commercial Warm Air Furnaces: CO_2 Total Emissions Reduction 13-5
Figure 13.3.2 Commercial Warm Air Furnaces: SO_2 Total Emissions Reduction 13-5
Figure 13.3.3 Commercial Warm Air Furnaces: NO_x Total Emissions Reduction 13-6
Figure 13.3.4 Commercial Warm Air Furnaces: Hg Total Emissions Reduction 13-6
Figure 13.3.5 Commercial Warm Air Furnaces: CH_4 Total Emissions Reduction 13-7
Figure 13.3.6 Commercial Warm Air Furnaces: N_2O Total Emissions Reduction 13-7

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).[4] 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).[2]

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 commercial buildings.

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 rule, EPA established a standard for hydrogen chloride as a surrogate for acid gas hazardous air

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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),

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 2023-2048 for the selected TSL (TSL 2), and 2019-2048 for the remaining TSLs. 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 Commercial Warm Air Furnaces*

	TSL**				
	1	2	3	4	5
Power Sector and Site Emissions					
CO_2 (million metric tons)	11.8	10.9	19.3	19.3	108.7
SO_2 (thousand tons)	0.390	0.384	0.613	0.645	-10.1
NO_X (thousand tons)	16.5	16.8	27.1	28.8	194
Hg (tons)	0.001	0.001	0.002	0.002	-0.043
CH_4 (thousand tons)	0.280	0.260	0.457	0.459	1.02
N_2O (thousand tons)	0.030	0.029	0.049	0.050	0.056
Upstream Emissions					
CO_2 (million metric tons)	1.65	1.53	2.71	2.72	17.37
SO_2 (thousand tons)	0.013	0.014	0.021	0.024	-0.061
NO_X (thousand tons)	26.4	24.4	43.3	43.5	279
Hg (tons)	0.000	0.000	0.000	0.000	0.000
CH_4 (thousand tons)	158	146	260	260	1,672
N_2O (thousand tons)	0.003	0.003	0.005	0.005	0.024
Total Emissions					
CO_2 (million metric tons)	13.4	12.4	22.0	22.0	126
SO_2 (thousand tons)	0.403	0.398	0.634	0.669	-10.2
NO_X (thousand tons)	43.0	41.2	70.5	72.2	473
Hg (tons)	0.001	0.001	0.002	0.002	-0.043
CH_4 (thousand tons)	159	146	260	260	1,673
CH_4 (thousand tons CO_2eq)†	4,440	4,096	7,289	7,292	46,831
N_2O (thousand tons)	0.033	0.032	0.054	0.055	0.080
N_2O (thousand tons CO_2eq)†	8.78	8.40	14.3	14.6	21.2

* Negative values refer to an increase in emissions.
** For TSL 2, the NES is forecasted over the lifetime of equipment sold from 2023-2048. For the other TSLs, the NES is forecasted over the lifetime of equipment sold from 2019-2048.
† CO_2eq is the quantity of CO_2 that would have the same global warming potential (GWP).

Figure 13.3.1 through Figure 13.3.6 show the annual reductions for total emissions for each type of emission from each TSL. The reductions reflect the lifetime impacts of products sold in 2023-2048 for the selected TSL (TSL 2), and 2019-2048 for the remaining TSLs.

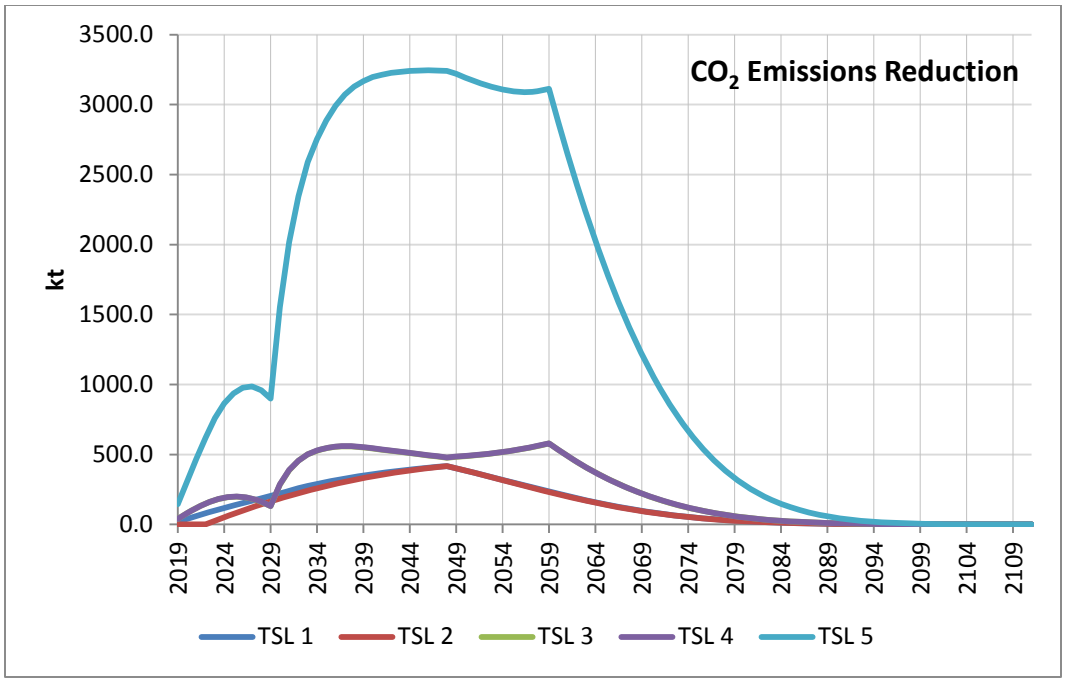

Figure 13.3.1 Commercial Warm Air Furnaces: CO_2 Total Emissions Reduction

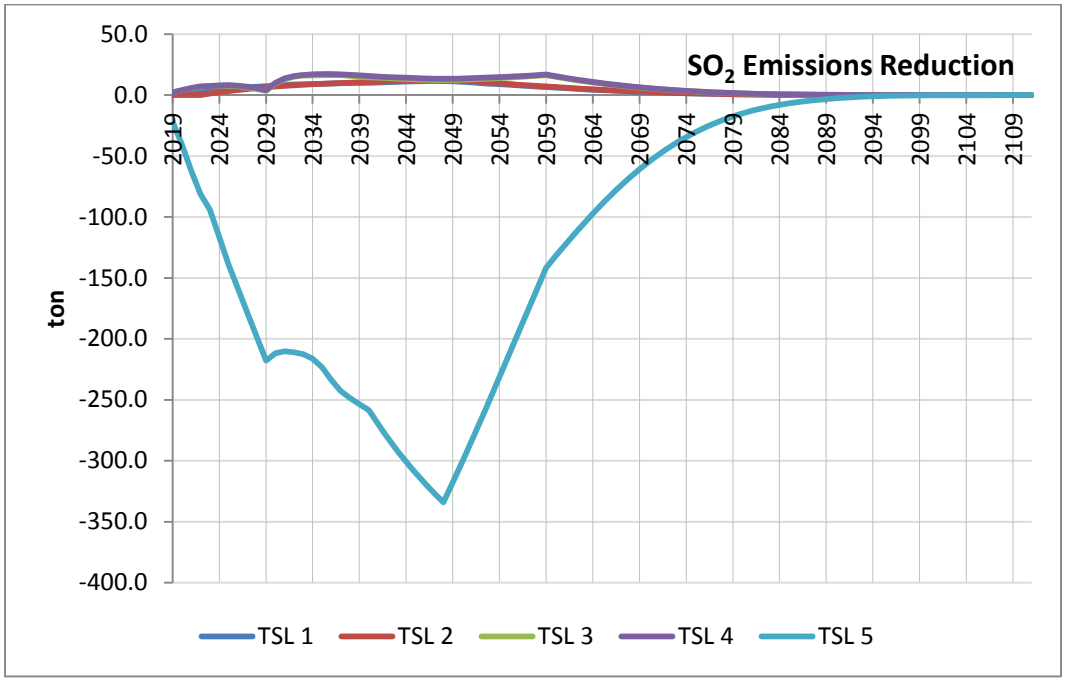

Figure 13.3.2 Commercial Warm Air Furnaces: SO_2 Total Emissions Reduction

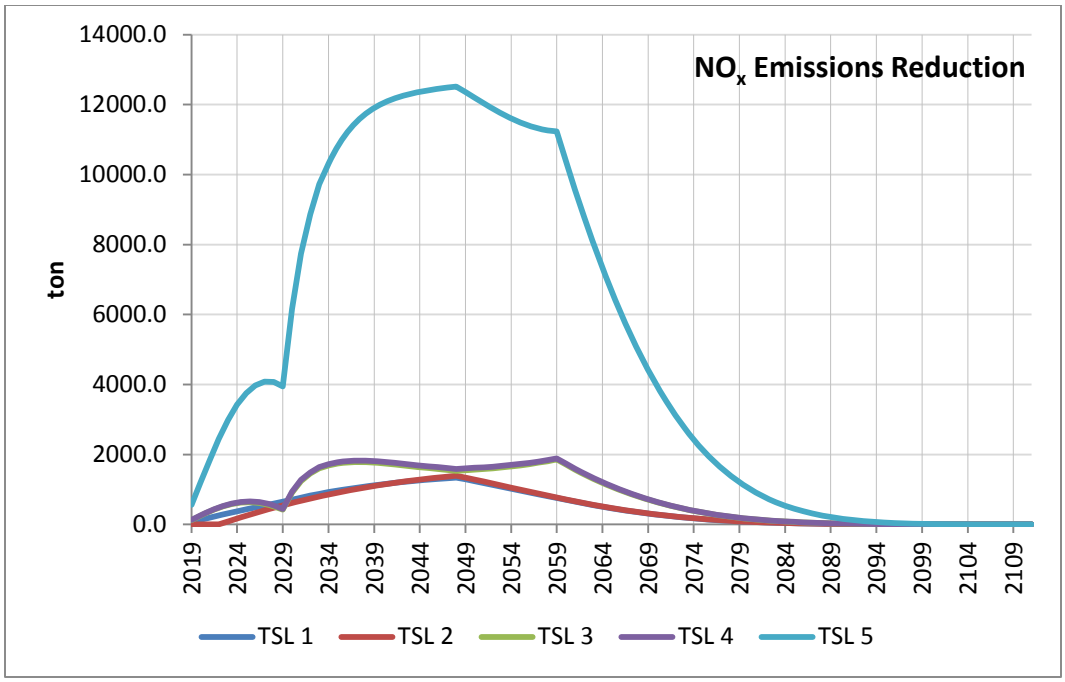

Figure 13.3.3 Commercial Warm Air Furnaces: NO_x Total Emissions Reduction

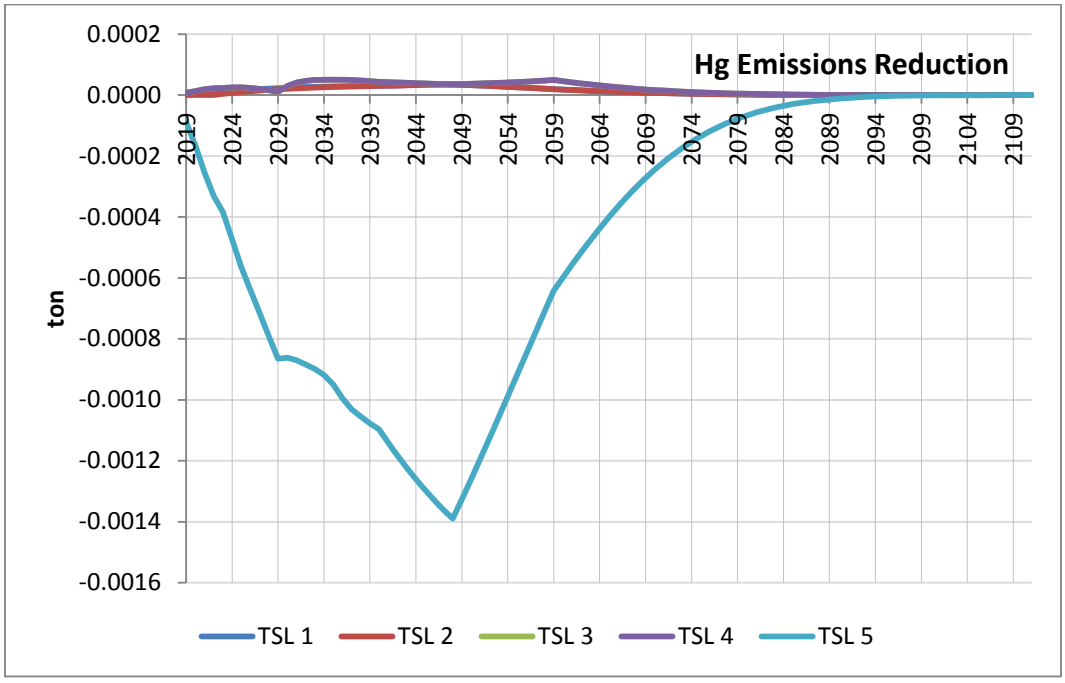

Figure 13.3.4 Commercial Warm Air Furnaces: Hg Total Emissions Reduction

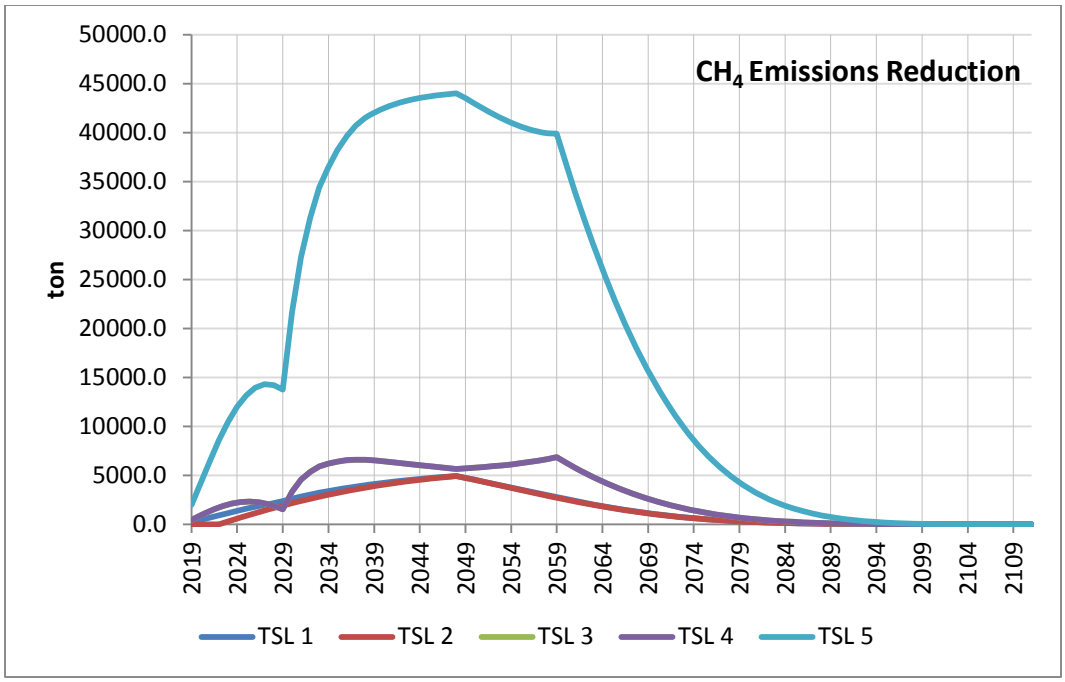

Figure 13.3.5 Commercial Warm Air Furnaces: CH_4 Total Emissions Reduction

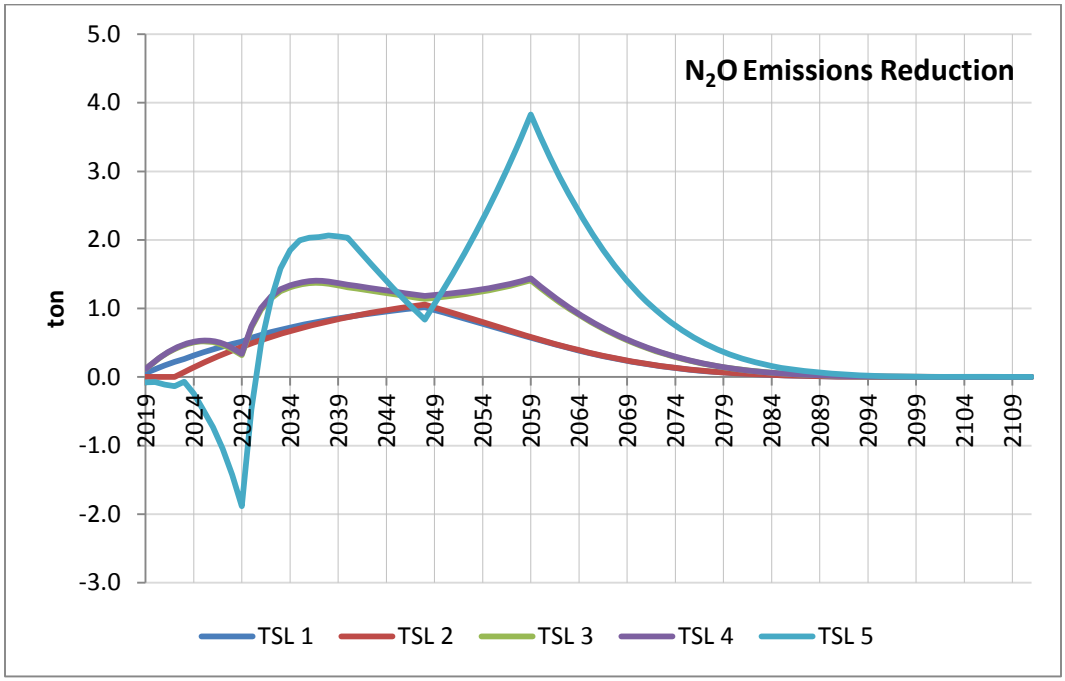

Figure 13.3.6 Commercial Warm Air Furnaces: N_2O Total Emissions Reduction

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APPENDIX 13A. EMISSIONS ANALYSIS METHODOLOGY

TABLE OF CONTENTS

13A.1 INTRODUCTION 13A-1
13A.2 POWER SECTOR AND SITE EMISSIONS FACTORS 13A-1
13A.3 UPSTREAM FACTORS 13A-2
13A.4 DATA TABLES 13A-2

LIST OF TABLES

Table 13A.4.1 Site Combustion Emissions Factors 13A-3
Table 13A.4.2 Power Sector Emissions Factors for CO_2 (Tons of CO_2 per kWh of Site Electricity Use) 13A-3
Table 13A.4.3 Power Sector Emissions Factors for Hg (tons/TWh) 13A-4
Table 13A.4.4 Power Sector Emissions Factors for NO_x (tons/MWh) 13A-5
Table 13A.4.5 Power Sector Emissions Factors for SO_2 (tons/MWh) 13A-6
Table 13A.4.6 Power Sector Emissions Factors for CH_4 (tons/MWh) 13A-7
Table 13A.4.7 Power Sector Emissions Factors for N_2O (tons/MWh) 13A-8
Table 13A.4.8 Electricity Upstream Emissions Factors 13A-8
Table 13A.4.9 Natural Gas Upstream Emissions Factors 13A-9
Table 13A.4.10 Fuel Oil Upstream Emissions Factors 13A-9

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 of 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 factors

published by the Environmental Protection Agency (EPA),[3] which are constant in time. These factors are presented in Table 13A.4.1.

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

TABLE OF CONTENTS

14.1 INTRODUCTION 14-1
14.2 MONETIZING CARBON DIOXIDE EMISSIONS 14-1
14.2.1 Social Cost of Carbon 14-1
14.2.2 Monetizing Carbon Dioxide Emissions 14-1
14.2.3 Current Approach and Key Assumptions 14-2
14.3 VALUATION OF OTHER EMISSIONS REDUCTIONS 14-5
14.4 RESULTS 14-6

LIST OF TABLES

Table 14.2.1 Annual SCC Values from 2010 Interagency Report, 2010 – 2050 (in 2007 dollars per metric ton) 14-4
Table 14.2.2 Annual SCC Values from 2013 Interagency Update (Revised July 2015), 2010–2050 (in 2007 dollars per metric ton CO_2) 14-4
Table 14.3.1 National Benefit per Ton for Emissions from Electricity Generating Units (2011$) 14-6
Table 14.4.1 Estimates of Global Present Value of CO_2 Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces 14-7
Table 14.4.2 Estimates of Domestic Present Value of CO_2 Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces 14-8
Table 14.4.3 Estimates of Present Value of NO_X Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces 14-9

CHAPTER 14. MONETIZATION OF EMISSION REDUCTIONS BENEFITS

14.1 INTRODUCTION

As part of its assessment of energy conservation standards for commercial warm air furnaces (CWAF), 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.[b] (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,[c] 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).[d] Table 14.2.2 shows the updated sets of SCC estimates in five year increments from 2010 to 2050. Appendix 14B 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.

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[b] *Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*. Interagency Working Group on Social Cost of Carbon, United States Government, February 2010. http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf

[c] 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.

[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. http://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

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.[e] 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.

[e] 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).[3] If the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2012),[4] 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.

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

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 TSL.

Table 14.4.1 Estimates of Global Present Value of CO_2 Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces

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	70.0	341	549	1039
2	62.6	310	500	946
3	110	544	879	1658
4	110	546	882	1663
5	614	3,053	4,940	9,314
Upstream Emissions				
1	9.84	47.9	77.1	146
2	8.80	43.5	70.3	133
3	15.5	76.5	124	233
4	15.5	76.8	124	234
5	99.0	490	793	1,495
Total Emissions				
1	79.8	388	626	1,185
2	71.4	353	571	1,078
3	126	620	1,003	1,891
4	126	622	1,006	1,897
5	713	3,543	5,733	10,809

* For each of the four cases, the corresponding SCC value for emissions in 2015 is $12.2, $40.0, $62.3, and $117 per metric ton (2014$).

** For TSL 2, the NES is forecasted over the lifetime of equipment sold from 2023-2048. For the other TSLs, the NES is forecasted over the lifetime of equipment sold from 2019-2048.

DOE calculated domestic values as a range of from 7 percent to 23 percent of the global values. Results for domestic values are presented in Table 14.4.2.

Table 14.4.2 Estimates of Domestic Present Value of CO_2 Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces

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	4.9 to 16.1	23.8 to 78.3	38.4 to 126.2	72.7 to 239.0
2	4.4 to 14.4	21.7 to 71.2	35.0 to 115.1	66.2 to 217.5
3	7.7 to 25.3	38.1 to 125.1	61.5 to 202.2	116.1 to 381.3
4	7.7 to 25.4	38.2 to 125.5	61.7 to 202.8	116.4 to 382.5
5	43.0 to 141.3	213.7 to 702.2	345.8 to 1,136.2	652.0 to 2,142.2
Upstream Emissions				
1	0.7 to 2.3	3.4 to 11.0	5.4 to 17.7	10.2 to 33.6
2	0.6 to 2.0	3.0 to 10.0	4.9 to 16.2	9.3 to 30.6
3	1.1 to 3.6	5.4 to 17.6	8.7 to 28.5	16.3 to 53.7
4	1.1 to 3.6	5.4 to 17.7	8.7 to 28.6	16.4 to 53.8
5	6.9 to 22.8	34.3 to 112.7	55.5 to 182.3	104.7 to 343.9
Total Emissions				
1	5.6 to 18.4	27.2 to 89.4	43.8 to 143.9	82.9 to 272.5
2	5.0 to 16.4	24.7 to 81.2	39.9 to 131.2	75.5 to 248.1
3	8.8 to 28.9	43.4 to 142.7	70.2 to 230.6	132.4 to 435.0
4	8.8 to 29.0	43.6 to 143.1	70.4 to 231.4	132.8 to 436.4
5	49.9 to 164.0	248.0 to 814.9	401.3 to 1,318.5	756.6 to 2,486.1

* 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 presents the present value of cumulative NO_X emissions reductions for each TSL, calculated using seven-percent and three-percent discount rates.

Table 14.4.3 Estimates of Present Value of NO_X Emissions Reduction for Potential Standards for Commercial Warm Air Furnaces

TSL	3% discount rate	7% discount rate
	Million 2014$	
Power Sector and Site Emissions		
1	46.1	16.3
2	44.9	14.7
3	72.2	24.7
4	76.8	26.3
5	516.3	173.6
Upstream Emissions		
1	73.6	26.0
2	65.4	21.4
3	115.3	39.5
4	115.7	39.6
5	741.3	249.3
Total Emissions		
1	119.6	42.3
2	110.4	36.1
3	187.6	64.2
4	192.4	65.9
5	1257.6	422.9

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APPENDIX 14A. SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866

TABLE OF CONTENTS

14A.1 EXECUTIVE SUMMARY 14A-1
14A.2 MONETIZING CARBON DIOXIDE EMISSIONS 14A-2
14A.3 SOCIAL COST OF CARBON VALUES USED IN PAST REGULATORY ANALYSES 14A-4
14A.4 APPROACH AND KEY ASSUMPTIONS 14A-5
14A.4.1 Integrated Assessment Models 14A-6
14A.4.2 Global versus Domestic Measures of SCC 14A-11
14A.4.3 Valuing Non-CO_2 Emissions 14A-13
14A.4.4 Equilibrium Climate Sensitivity 14A-14
14A.4.5 Socioeconomic and Emissions Trajectories 14A-17
14A.4.6 Discount Rate 14A-19
14A.5 REVISED SCC ESTIMATES 14A-26
14A.6 LIMITATIONS OF THE ANALYSIS 14A-33
14A.7 A FURTHER DISCUSSION OF CATASTROPHIC IMPACTS AND DAMAGE FUNCTIONS 14A-35
14A.8 CONCLUSION 14A-38
14A.9 ANNEX 14A-46
14A.9.1 Other (non-CO_2) gases 14A-47
14A.9.2 Extrapolating Emissions Projections to 2300 ..... 14A-49

LIST OF TABLES

Table 14A.1.1 Social Cost of CO_2, 2010 – 2050 (in 2007 dollars) 14A-2
Table 14A.4.1 Summary Statistics for Four Calibrated Climate Sensitivity Distributions 14A-15
Table 14A.4.2 Socioeconomic and Emissions Projections from Select EMF-22 Reference Scenarios 14A-18
Table 14A.5.1 Disaggregated Social Cost of CO_2 Values by Model, Socioeconomic Trajectory, and Discount Rate for 2010 (in 2007 dollars) 14A-30
Table 14A.5.2 Social Cost of CO_2, 2010 – 2050 (in 2007 dollars) 14A-32
Table 14A.5.3 Changes in the Average Annual Growth Rates of SCC Estimates between 2010 and 2050 ..... 14A-32
Table 14A.7.1 Probabilities of Various Tipping Points from Expert Elicitation 14A-36
Table 14A.9.1 Annual SCC Values: 2010–2050 (in 2007 dollars) 14A-46
Table 14A.9.2 2010 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/ton CO_2) 14A-57
Table 14A.9.3 2010 Global SCC Estimates at 3 Percent Discount Rate (2007$/ton CO_2) 14A-58
Table 14A.9.4 2010 Global SCC Estimates at 5 Percent Discount Rate (2007$/ton CO_2) 14A-59

Table 14A.9.5 Additional Summary Statistics of 2010 Global SCC Estimates 14A-60

LIST OF FIGURES

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..... 14A-10
Figure 14A.4.2 Annual Consumption Loss for Lower Temperature Changes in DICE, FUND, and PAGE 14A-11
Figure 14A.4.3 Estimates of the Probability Density Function for Equilibrium Climate Sensitivity (°C) 14A-16
Figure 14A.5.1 Level of Global GDP across EMF Scenarios 14A-31
Figure 14A.9.2 Sulfur Dioxide Emission Scenarios 14A-49
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.) 14A-51
Figure 14A.9.4 World GDP, 2000-2300 (Post-2100 extrapolations assume GDP per capita growth declines linearly, reaching zero in the year 2300) 14A-52
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) 14A-53
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) 14A-54
Figure 14A.9.7 Global Non-CO_2 Radiative Forcing, 2000-2300 (Post-2100 extrapolations assume constant non-CO_2 radiative forcing after 2100). 14A-55
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)..... 14A-56
Figure 14A.9.9 Histogram of Global SCC Estimates in 2010 (2007$/ton CO_2), by discount rate* 14A-59

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.

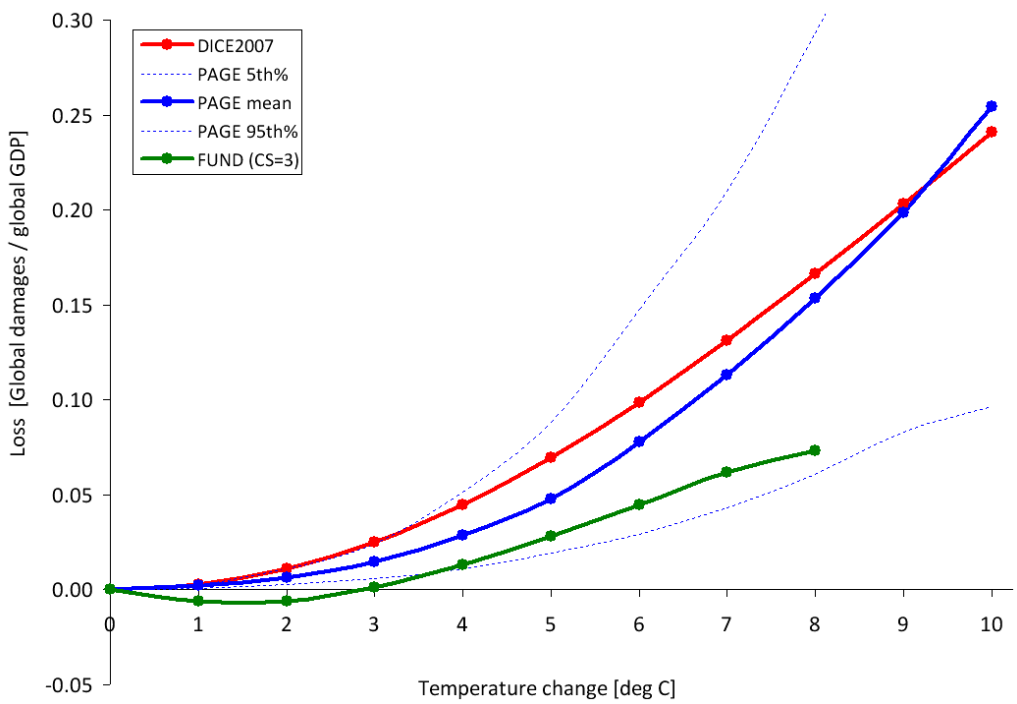

Figure 14A.4.1 Annual Consumption Loss as a Fraction of Global GDP in 2100 Due to an Increase in Annual Global Temperature in the DICE, FUND, and PAGE models[f]

[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.

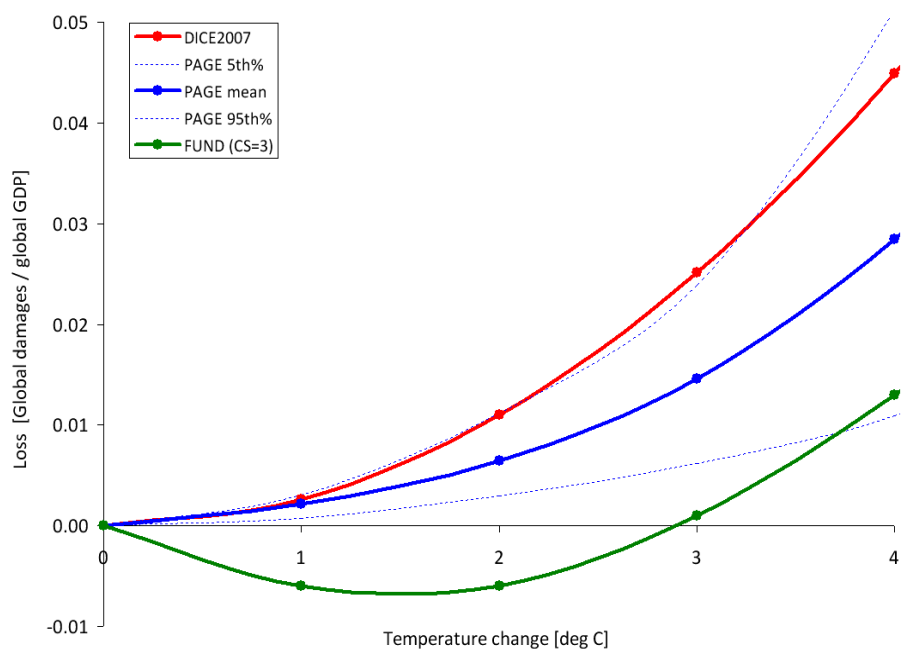

Figure 14A.4.2 Annual Consumption Loss for Lower Temperature Changes in DICE, FUND, and PAGE

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.

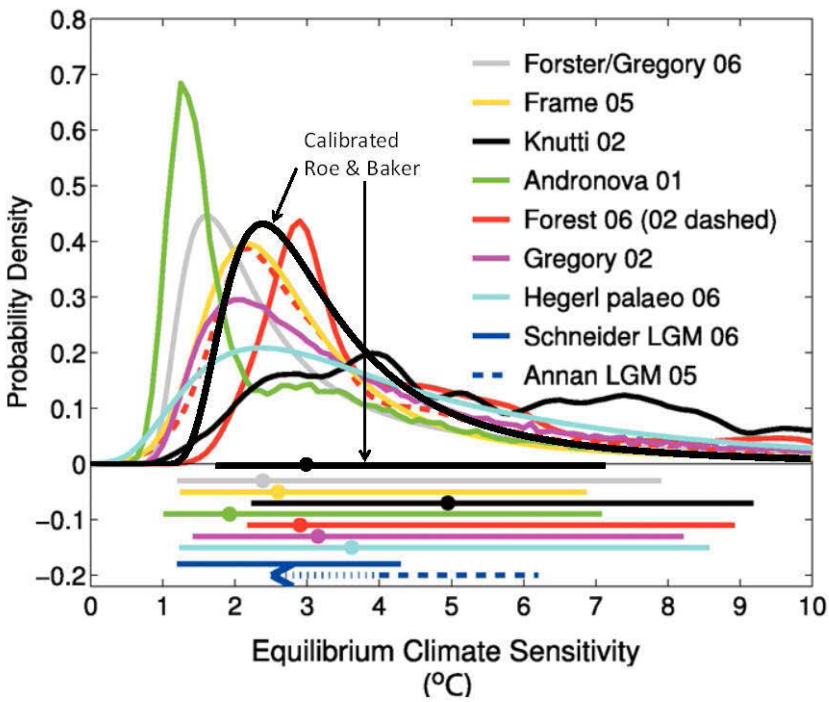

Figure 14A.4.3 Estimates of the Probability Density Function for Equilibrium Climate Sensitivity (°C)

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.

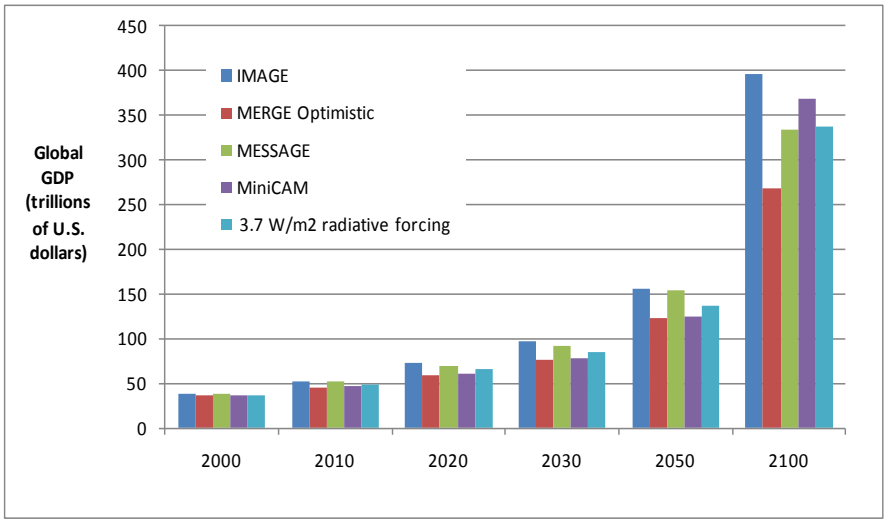

Figure 14A.5.1 Level of Global GDP across EMF Scenarios

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.

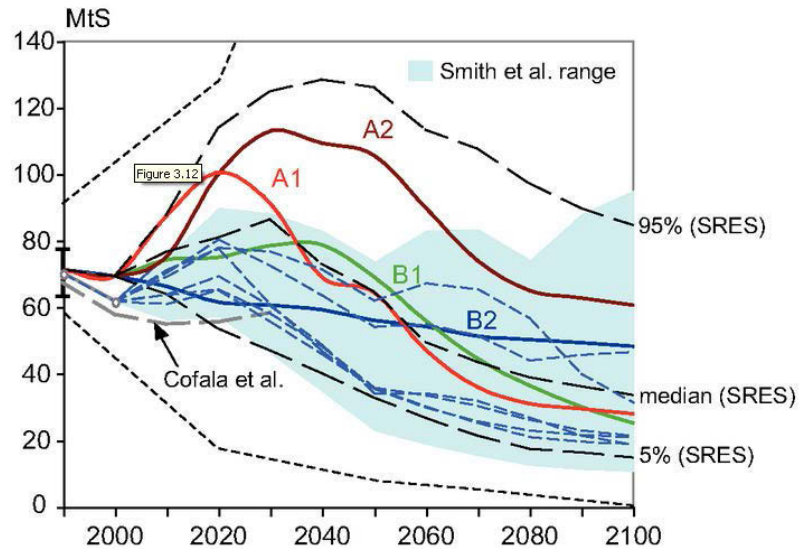

Figure 14A.9.2 Sulfur Dioxide Emission Scenarios

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

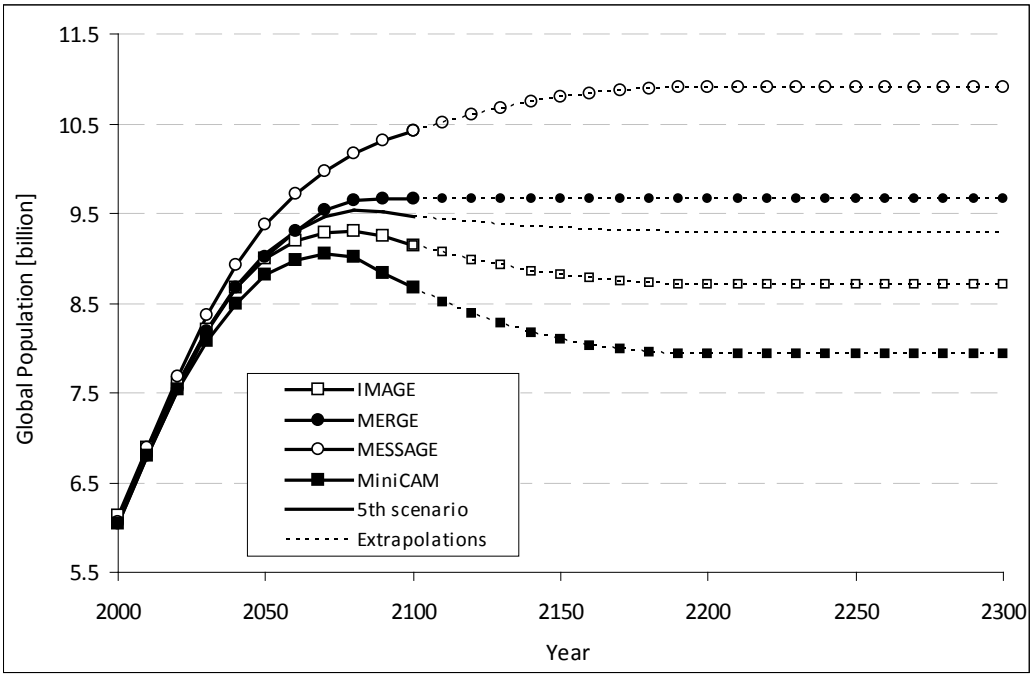

Figure 14A.9.3 Global Population, 2000-2300 (Post-2100 extrapolations assume the population growth rate changes linearly to reach a zero growth rate by 2200.)

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.

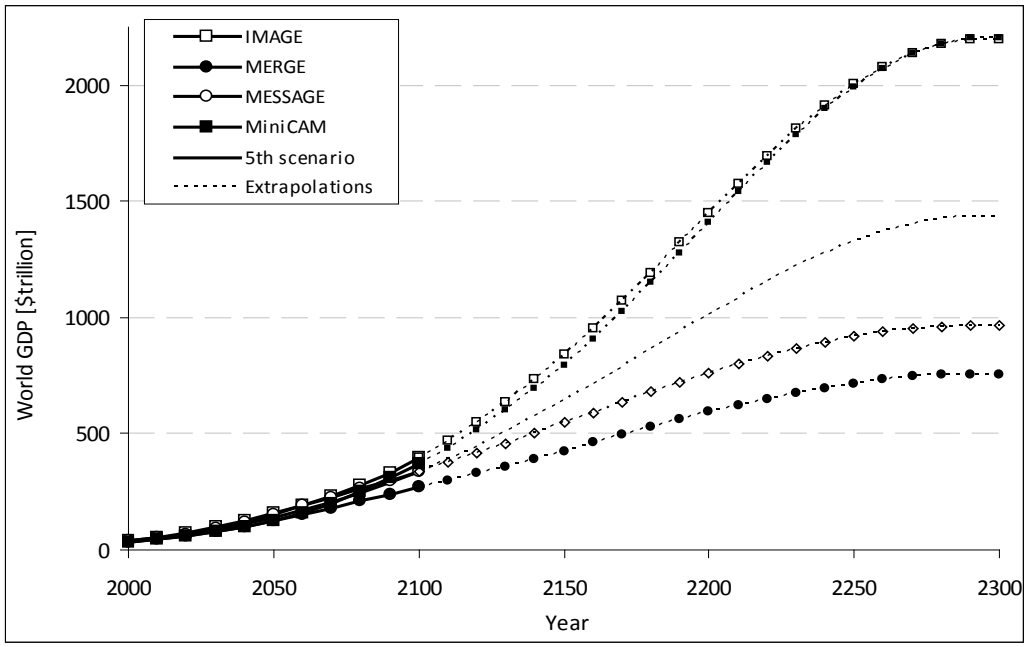

Figure 14A.9.4 World GDP, 2000-2300 (Post-2100 extrapolations assume GDP per capita growth declines linearly, reaching zero in the year 2300)

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.

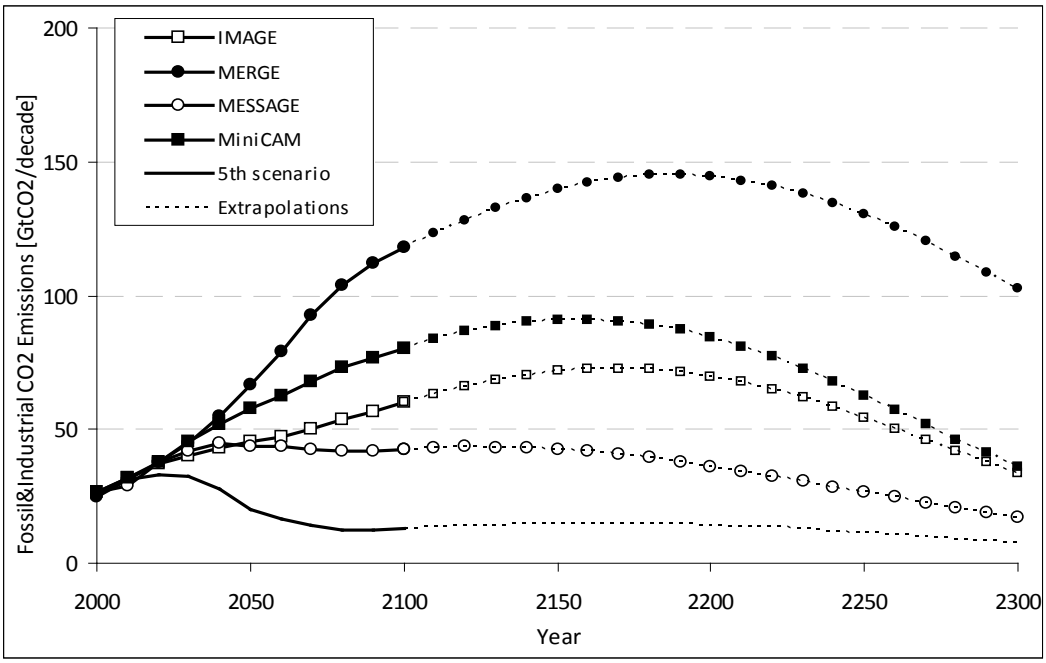

Figure 14A.9.5 Global Fossil and Industrial CO_2 Emissions, 2000-2300 (Post-2100 extrapolations assume growth rate of CO_2 intensity (CO_2/GDP) over 2090-2100 is maintained through 2300)

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.

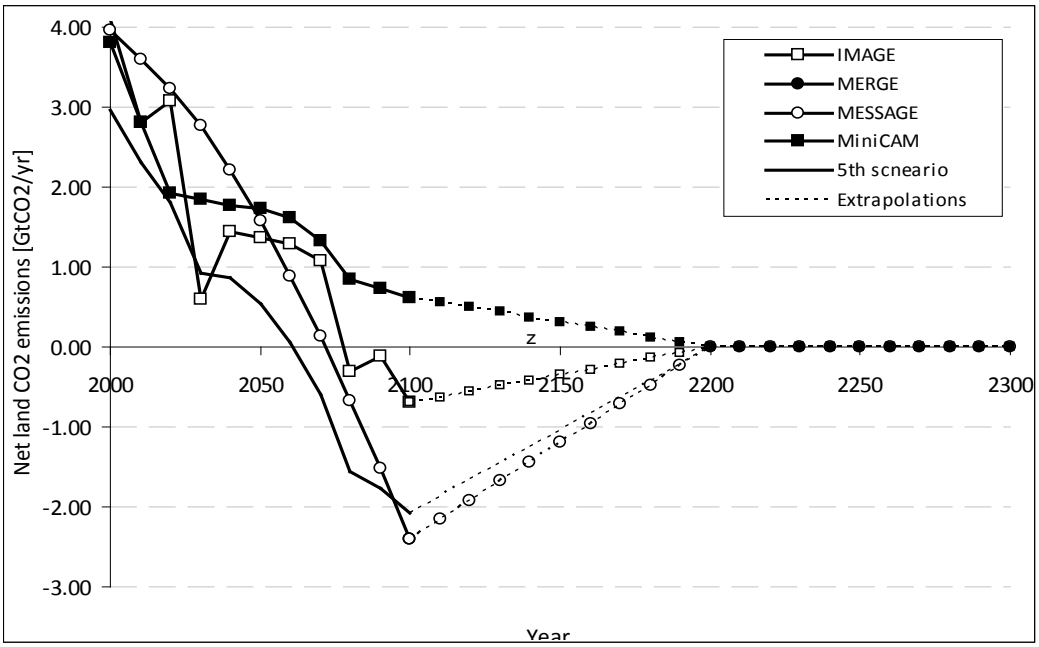

Figure 14A.9.6 Global Net Land Use CO_2 Emissions, 2000-2300 (Post-2100 extrapolations assume emissions decline linearly, reaching zero in the year 2200)[kk]

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).

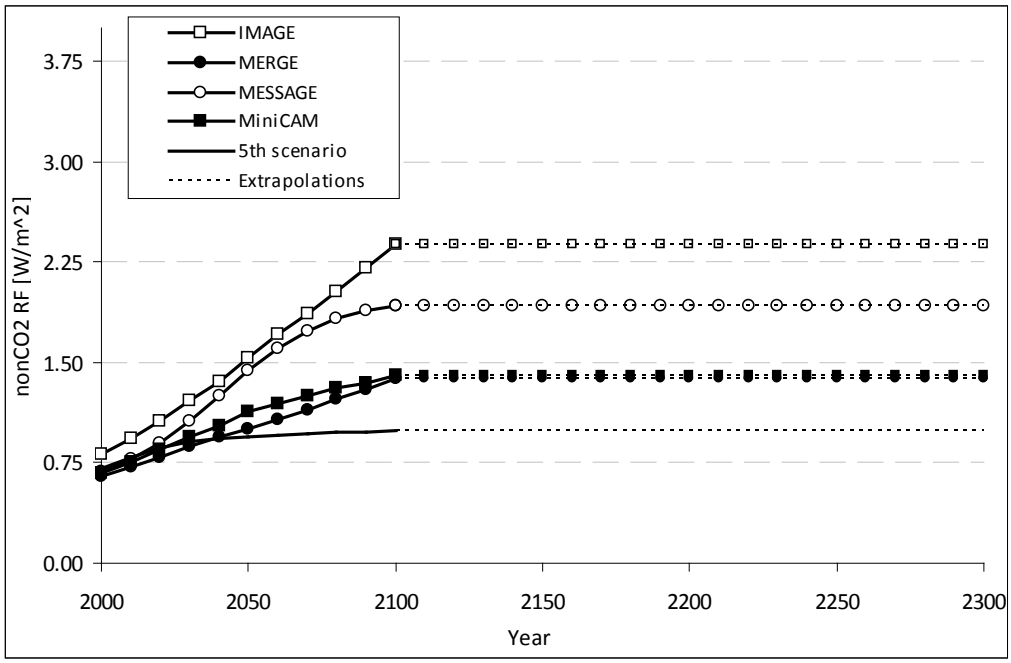

Figure 14A.9.7 Global Non-CO_2 Radiative Forcing, 2000-2300 (Post-2100 extrapolations assume constant non-CO_2 radiative forcing after 2100)

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.

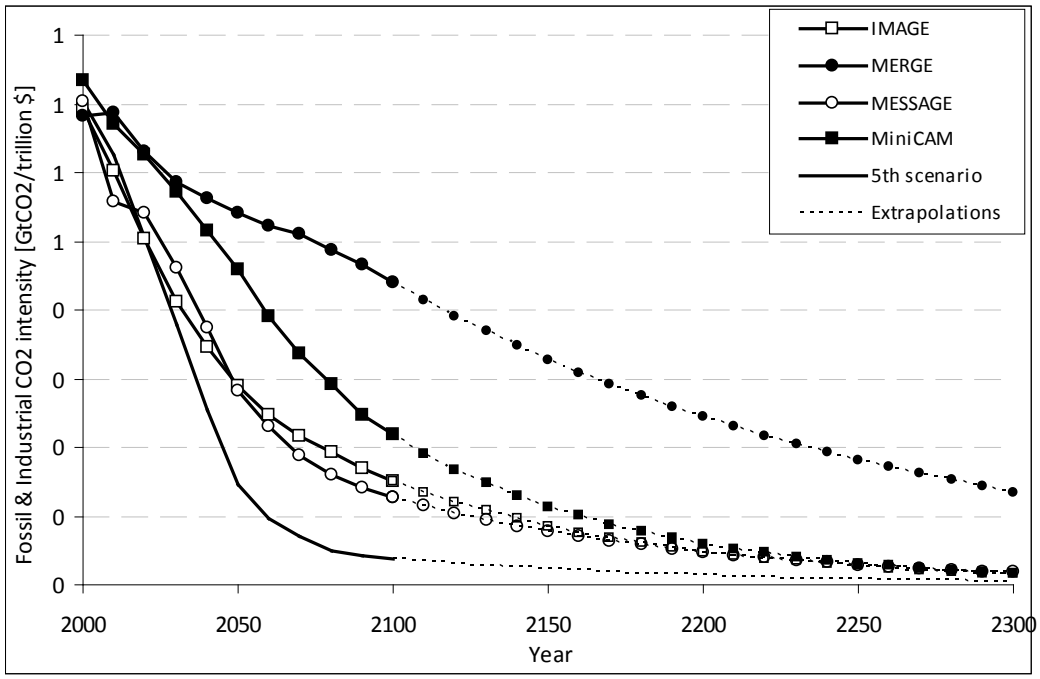

Figure 14A.9.8 Global CO_2 Intensity (fossil & industrial CO_2 emissions/GDP), 2000-2300 (Post-2100 extrapolations assume decline in CO_2/GDP growth rate over 2090-2100 is maintained through 2300)

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

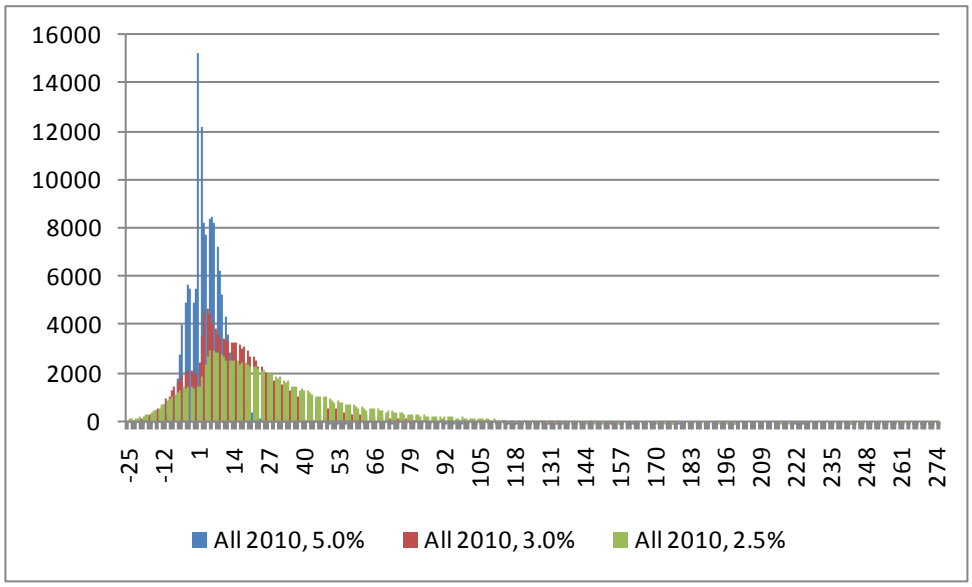

Figure 14A.9.9 Histogram of Global SCC Estimates in 2010 (2007$/ton CO_2), by discount rate*

* 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

TABLE OF CONTENTS

14B.1 PREFACE 14B-1
14B.2 EXECUTIVE SUMMARY 14B-1
14B.3 PURPOSE 14B-2
14B.4 SUMMARY OF MODEL UPDATES 14B-3
14B.4.1 DICE 14B-3
14B.4.1.1 Carbon Cycle Parameters 14B-4
14B.4.1.2 Sea Level Dynamics 14B-4
14B.4.1.3 Re-calibrated Damage Function 14B-5
14B.4.2 FUND 14B-6
14B.4.2.1 Space Heating 14B-6
14B.4.2.2 Sea Level Rise and Land Loss 14B-6
14B.4.2.3 Agriculture 14B-7
14B.4.2.4 Temperature Response Model 14B-7
14B.4.2.5 Methane 14B-8
14B.4.3 PAGE 14B-8
14B.4.3.1 Sea Level Rise 14B-8
14B.4.3.2 Revised Damage Function to Account for Saturation 14B-8
14B.4.3.3 Regional Scaling Factors 14B-9
14B.4.3.4 Probability of a Discontinuity 14B-9
14B.4.3.5 Adaptation 14B-9
14B.4.3.6 Other Noteworthy Changes 14B-10
14B.5 REVISED SCC ESTIMATES 14B-10
14B.6 OTHER MODEL LIMITATIONS OR RESEARCH GAPS 14B-12
14B.7 ANNEX A 14B-15
14B.8 ANNEX B 14B-1

LIST OF TABLES

Table 14B.2.1 Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per ton of CO_2) 14B-2
Table 14B.4.1 Summary of Key Model Revisions Relevant to the Interagency SCC 14B-3
Table 14B.5.1 Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per ton of CO_2) 14B-11
Table 14B.5.2 Average Annual Growth Rates of SCC Estimates between 2010 and 2050 ..... 14B-12
Table 14B.7.1 Annual SCC Values: 2010-2050 (2007$/ton CO_2) 14B-15
Table 14B.7.2 202 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/ton CO_2) 14B-16
Table 14B.7.3 SCC Estimates at 3 Percent Discount Rate (2007$/ton CO2) 14B-16

Table 14B.7.4 2020 Global SCC Estimates at 5 Percent Discount Rate (2007$/ton CO_2) 14B-17
Table 14B.7.5 Additional Summary Statistics of 2020 Global SCC Estimates 14B-1

LIST OF FIGURES

Figure 14B.5.1 Distribution of SCC Estimates for 2010 (in 2007$ per ton CO_2) 14B-11

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] http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866/eo13563_01182011.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: http://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] http://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.

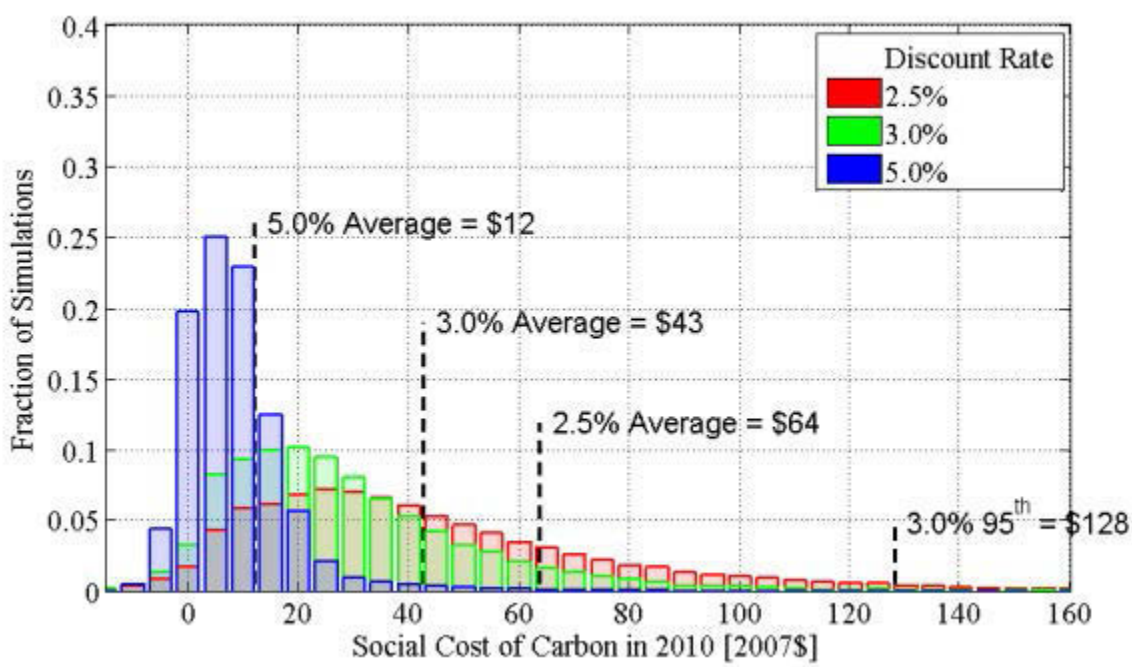

Figure 14B.5.1 Distribution of SCC Estimates for 2010 (in 2007$ per ton CO_2)

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

TABLE OF CONTENTS

15.1 INTRODUCTION 15-1
15.2 METHODOLOGY 15-1
15.3 UTILITY IMPACT RESULTS 15-2
15.3.1 Installed Capacity 15-2
15.3.2 Electricity Generation 15-5
15.3.3 Results Summary 15-8

LIST OF TABLES

Table 15.3.1 Commercial Warm Air Furnaces: Summary of Utility Impact Results* 15-8

LIST OF FIGURES

Figure 15.3.1 Commercial Warm Air Furnaces: Total Electric Capacity Reduction 15-3
Figure 15.3.2 Commercial Warm Air Furnaces: Coal Capacity Reduction 15-3
Figure 15.3.3 Commercial Warm Air Furnaces: Nuclear Capacity Reduction 15-4
Figure 15.3.4 Commercial Warm Air Furnaces: Gas Combined Cycle Capacity Reduction 15-4
Figure 15.3.5 Commercial Warm Air Furnaces: Renewables Capacity Reduction 15-5
Figure 15.3.6 Commercial Warm Air Furnaces: Total Generation Reduction 15-6
Figure 15.3.7 Commercial Warm Air Furnaces: Coal Generation Reduction 15-6
Figure 15.3.8 Commercial Warm Air Furnaces: Nuclear Generation Reduction 15-7
Figure 15.3.9 Commercial Warm Air Furnaces: Gas Combined Cycle Generation Reduction 15-7
Figure 15.3.10 Commercial Warm Air Furnaces: Renewables Generation Reduction 15-8

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 *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 commercial warm air furnaces (CWAF).

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 CWAF, DOE used the impact factors for space heating in commercial buildings.

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. 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.

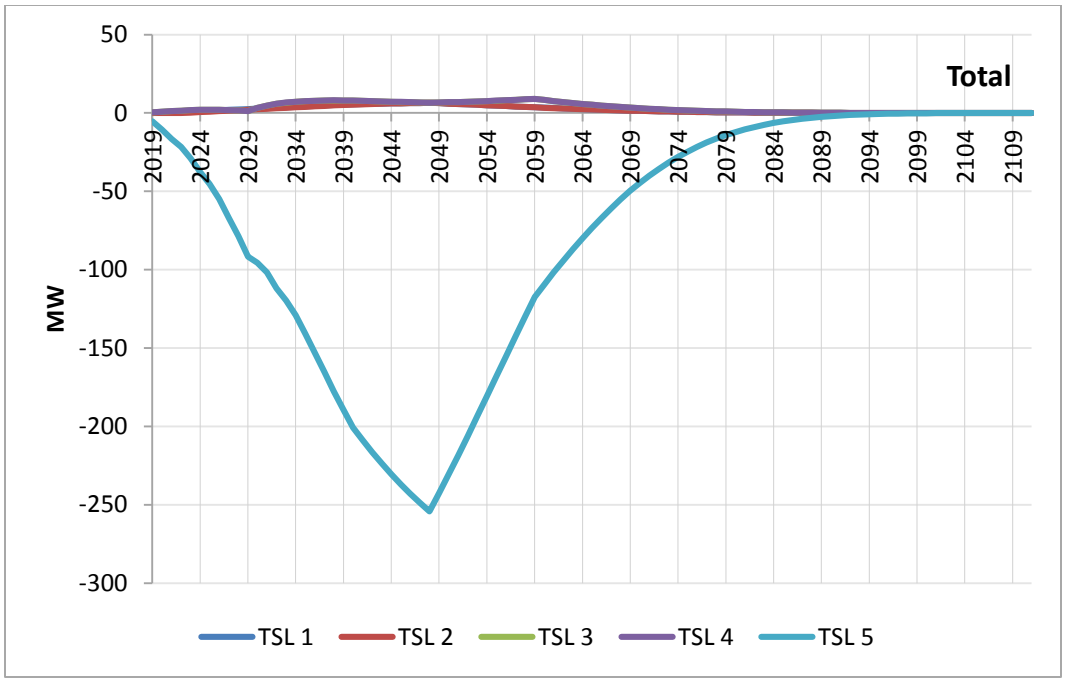

Figure 15.3.1 Commercial Warm Air Furnaces: Total Electric Capacity Reduction

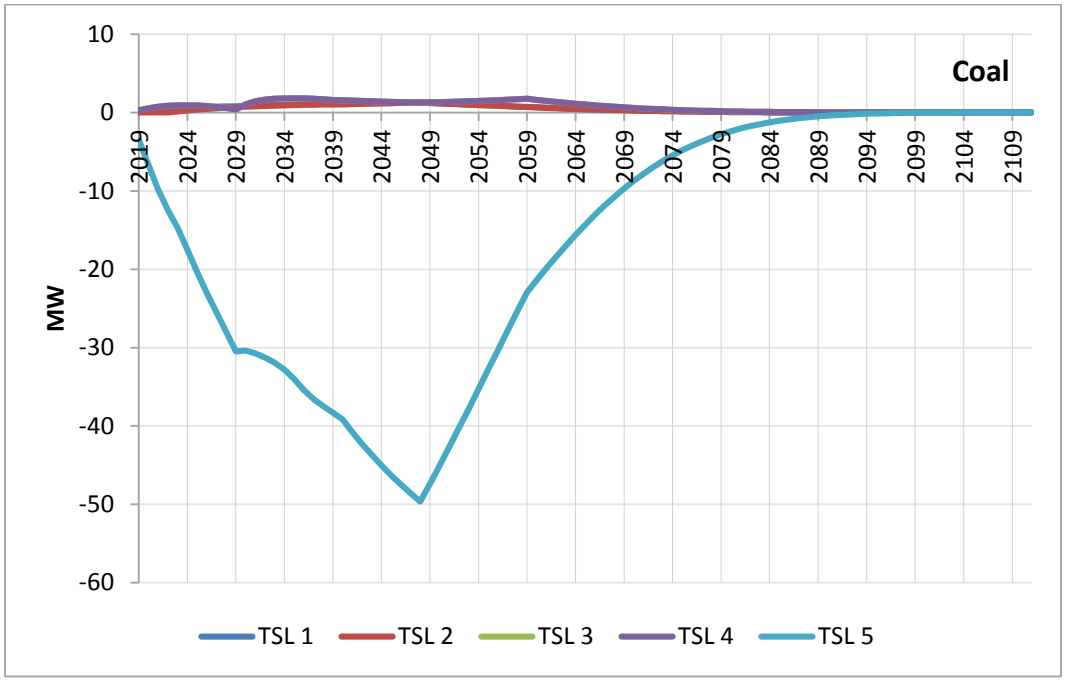

Figure 15.3.2 Commercial Warm Air Furnaces: Coal Capacity Reduction

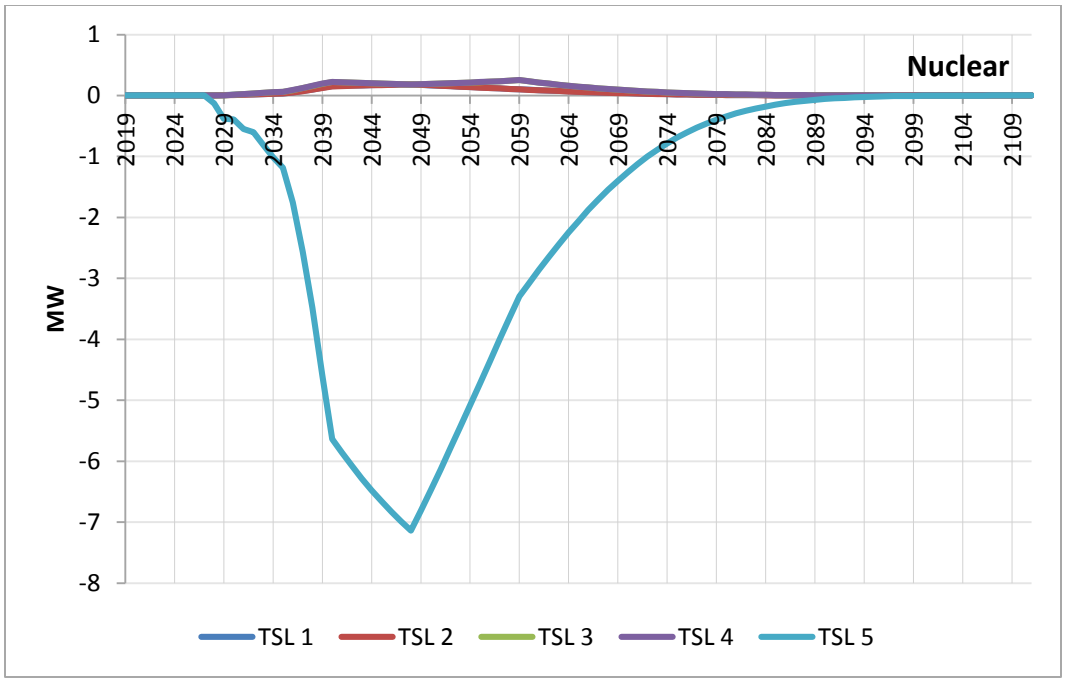

Figure 15.3.3 Commercial Warm Air Furnaces: Nuclear Capacity Reduction

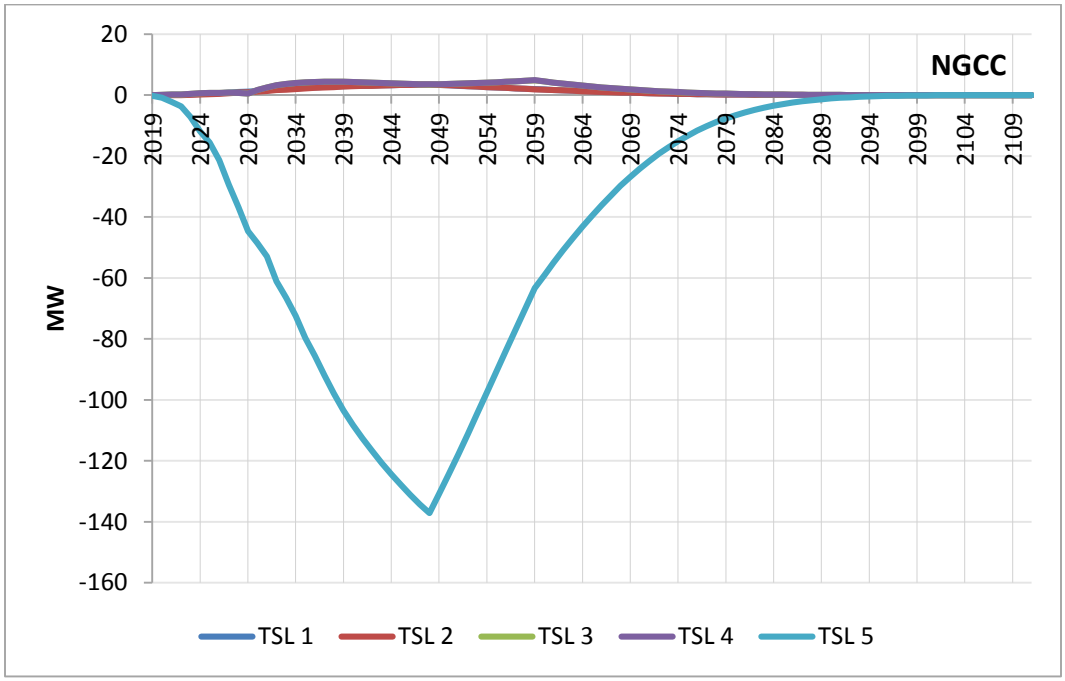

Figure 15.3.4 Commercial Warm Air Furnaces: Gas Combined Cycle Capacity Reduction

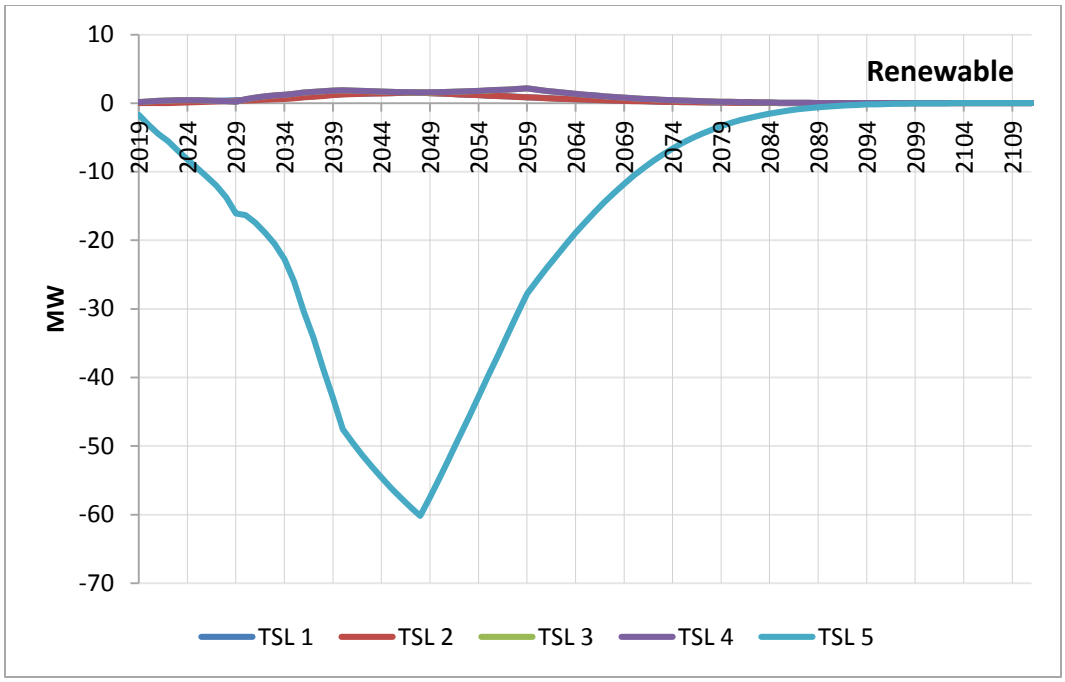

Figure 15.3.5 Commercial Warm Air Furnaces: Renewables Capacity Reduction

15.3.2 Electricity Generation

The figures in this section show the annual change in electricity generation that result for each TSL by fuel type. The change by fuel type has been calculated based on factors calculated as described in appendix 15A.

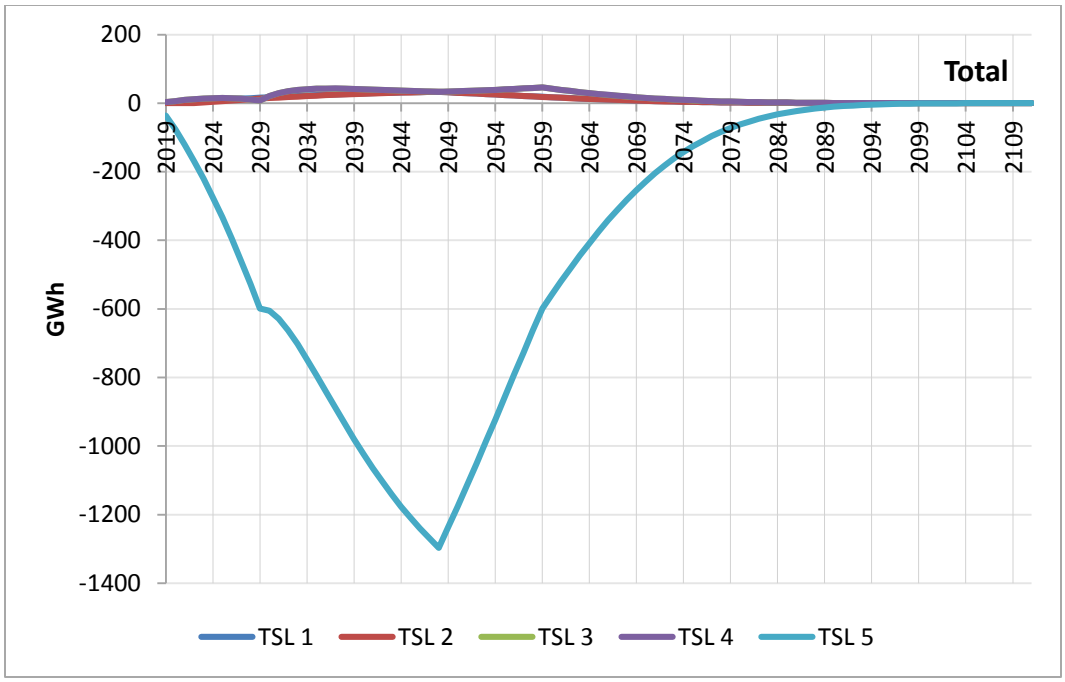

Figure 15.3.6 Commercial Warm Air Furnaces: Total Generation Reduction

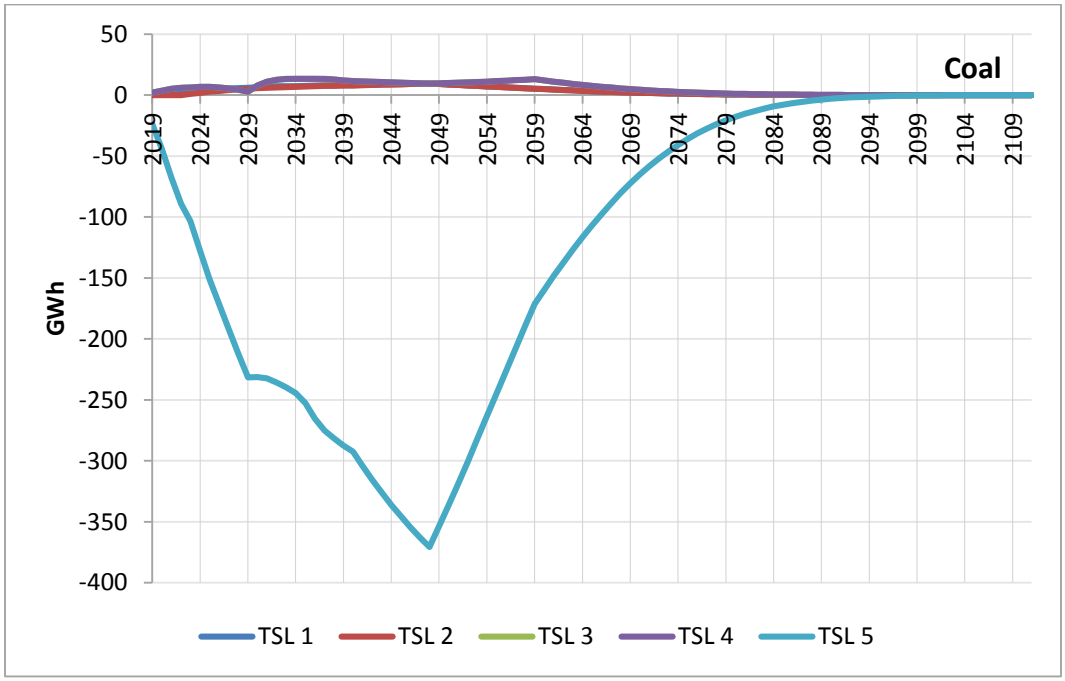

Figure 15.3.7 Commercial Warm Air Furnaces: Coal Generation Reduction

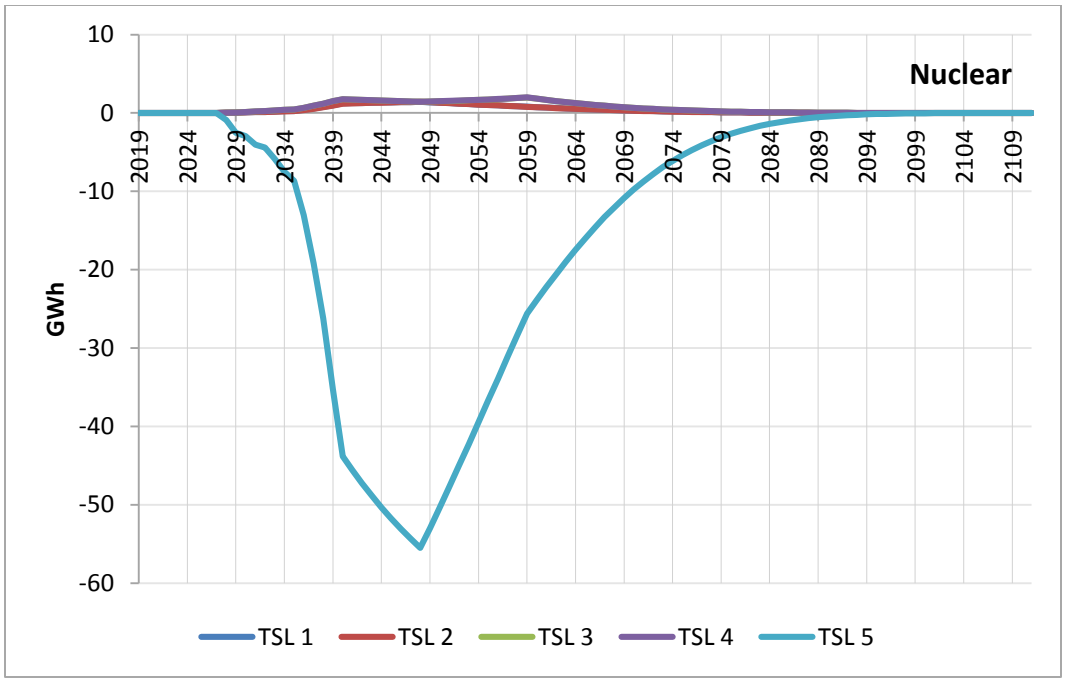

Figure 15.3.8 Commercial Warm Air Furnaces: Nuclear Generation Reduction

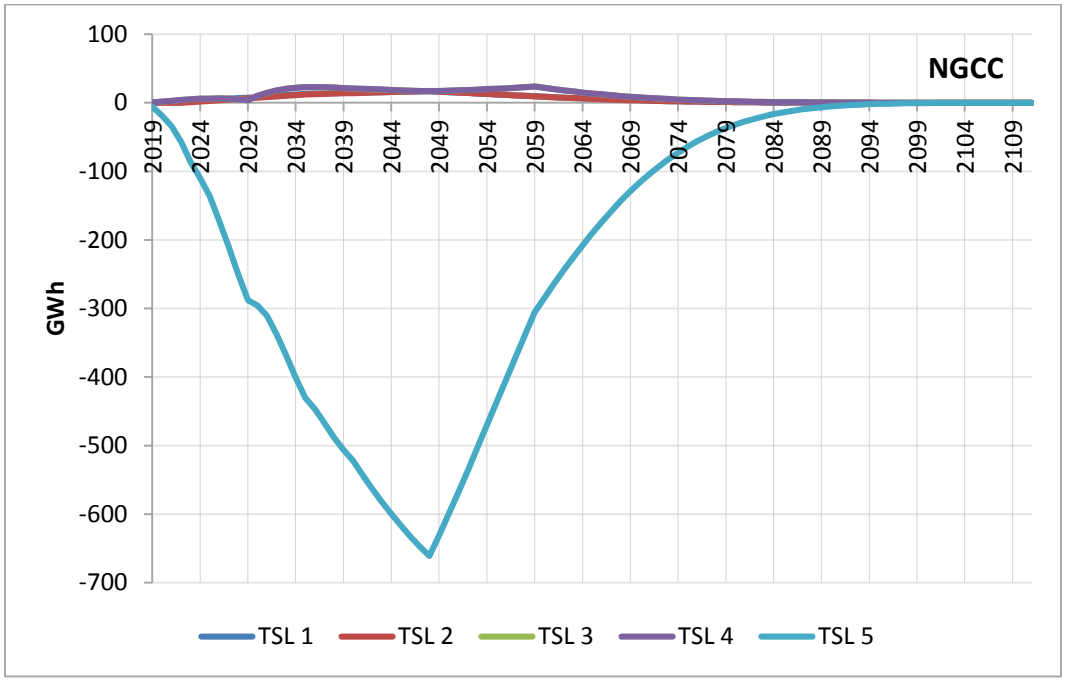

Figure 15.3.9 Commercial Warm Air Furnaces: Gas Combined Cycle Generation Reduction

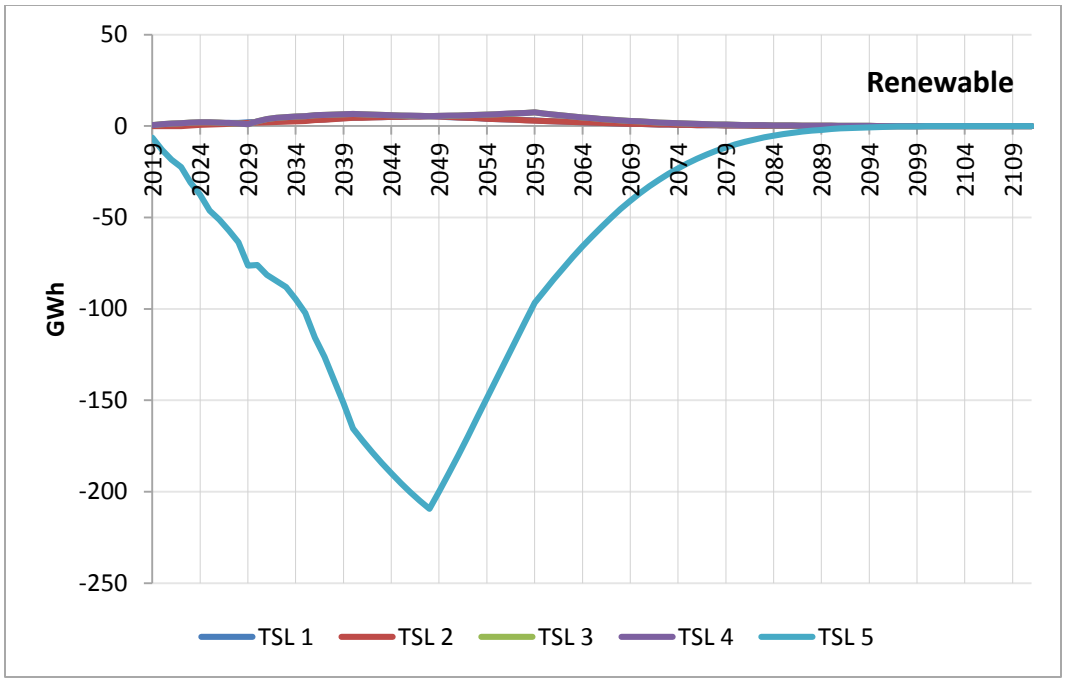

Figure 15.3.10 Commercial Warm Air Furnaces: Renewables Generation Reduction

15.3.3 Results Summary

Table 15.3.1 presents a summary of the utility impact results for CWAF.

Table 15.3.1 Commercial Warm Air Furnaces: Summary of Utility Impact Results*

	TSL				
	1	2	3	4	5
Installed Capacity Reduction (MW)					
2020	0.441	--	0.882	0.884	-10.7
2025	1.45	0.827	2.03	2.03	-45.3
2030	2.76	2.34	3.28	3.29	-95.6
2035	4.24	3.90	7.45	7.47	-141
2040	5.57	5.38	7.94	7.96	-201
Electricity Generation Reduction (GWh)					
2020	3.14	--	6.27	6.29	-76.3
2025	10.6	6.08	14.9	14.9	-333
2030	17.5	14.8	20.8	20.8	-605
2035	23.9	22.0	42.0	42.1	-794
2040	28.4	27.5	40.5	40.6	-1024

* Negative values refer to an increase in capacity and/or generation.

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3. Coughlin, K. *Utility Sector Impacts of Reduced Electricity Demand*, 2014. Lawrence Berkeley National Laboratory. Report No. LBNL-6864E. http://www.osti.gov/scitech/biblio/1165372/

APPENDIX 15A. UTILITY IMPACT ANALYSIS METHODOLOGY

TABLE OF CONTENTS

15A.1 INTRODUCTION 15A-1
15A.2 METHODOLOGY 15A-1
15A.3 MODEL RESULTS 15A-4
15A.3.1 Electricity Generation 15A-4
15A.3.2 Installed Capacity 15A-5

LIST OF TABLES

Table 15A.3.1 Fuel-Share Weights by Sector and End-Use (Values for 2020) 15A-5
Table 15A.3.2 Capacity Impact Factors in GW per TWh Reduced Site Electricity Demand (Values for 2020) 15A-6

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 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 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

TABLE OF CONTENTS

16.1 INTRODUCTION 16-1
16.2 ASSUMPTIONS 16-1
16.3 METHODOLOGY 16-1
16.4 SHORT-TERM RESULTS 16-2
16.5 LONG-TERM RESULTS 16-3

LIST OF TABLES

Table 16.4.1 Net National Short-term Change in Employment (Number of Jobs) 16-3

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 commercial warm air furnaces (CWAF). Job increases or decreases reported in this chapter are separate from the direct furnace 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 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 CWAF 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 CWAF 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 CWAF 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 furnaces; 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 spent 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 furnaces 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 presents the modeled net employment impact from the rule in 2019 (2023 for TSL 2), rounded to the nearest ten jobs. Virtually all CWAF are domestically produced, so DOE does not consider imports in this analysis.

Table 16.4.1 Net National Short-term Change in Employment (Number of Jobs)

Trial Standard Level	2019	2023	2024	2028
TSL 1	10	--	30	--
TSL 2	--	10	--	40
TSL 3	90	--	140	--
TSL 4	90	--	140	--
TSL 5	230	--	410	--

For context, the Office of Management of Budget currently assumes that the unemployment rate may decline 5.4 percent by 2019.[5] The unemployment rate in 2019 is projected to be 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 2024 (2028 for TSL 2), are included in the second column of Table 16.4.1.

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CHAPTER 17. REGULATORY IMPACT ANALYSIS

TABLE OF CONTENTS

17.1 INTRODUCTION 17-1
17.2 NON-REGULATORY POLICIES 17-2
17.2.1 Methodology 17-2
17.2.2 Assumptions Regarding Non-Regulatory Policies 17-3
17.2.3 Policy Interactions 17-4
17.3 NON-REGULATORY POLICY ASSUMPTIONS 17-4
17.3.1 No New Regulatory Action 17-4
17.3.2 Consumer Rebates 17-4
17.3.2.1 Methodology 17-4
17.3.2.2 Analysis 17-5
17.3.3 Consumer Tax Credits 17-9
17.3.4 Manufacturer Tax Credits 17-10
17.3.5 Voluntary Energy Efficiency Targets 17-11
17.3.6 Bulk Government Purchases 17-13
17.4 IMPACTS OF NON-REGULATORY ALTERNATIVES 17-14

LIST OF TABLES

Table 17.1.1 Non-Regulatory Alternatives to National Standards 17-1
Table 17.2.1 Efficiency Levels for Trial Standard Levels for Gas-Fired Commercial Warm Air Furnaces 17-3
Table 17.3.1 Benefit/Cost Ratios Without and With Rebates for Gas-Fired Commercial Warm Air Furnaces 17-6
Table 17.3.2 Market Penetrations in the Effective Year of Standards Attributable to Consumer Rebates for Gas-Fired Commercial Warm Air Furnaces 17-8
Table 17.3.3 Market Penetrations in the Effective Year of Standards Attributable to Consumer Tax Credits for Gas-Fired Commercial Warm Air Furnaces 17-10
Table 17.3.4 Market Penetrations in the Effective Year of Standards Attributable to Manufacturer Tax Credits for Gas-Fired Commercial Warm Air Furnaces 17-11
Table 17.3.5 Market Penetrations in the Effective Year of Standards Attributable to Voluntary Energy Efficiency Targets for Gas-Fired Commercial Warm Air Furnaces 17-12
Table 17.3.6 Market Penetrations in the Effective Year of Standards Attributable to Bulk Government Purchasing of Gas-Fired Commercial Warm Air Furnaces 17-14
Table 17.4.1 Impacts of Non-Regulatory Alternatives for Gas-Fired Commercial Warm Air Furnaces at TSL 2 17-16

LIST OF FIGURES

Figure 17.3.1 Market Penetration Curves for Gas-Fired Commercial Warm Air Furnaces 17-8
Figure 17.4.1 Market Penetration of Gas-Fired Commercial Warm Air Furnaces Meeting the Target Level in Policy Cases at TSL 2 17-15

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)-Regulatory Impact Analysis (RIA model built on a modified[a] version of the NIA model 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 (TSLs) for the commercial warm air furnaces (CWAFs) 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 TSLs for the equipment class of CWAFs covered by this RIA.[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 six selected policies listed above (excluding the alternative of no new regulatory action). Section 17.4 presents the results of the policy alternatives.

[a] For this RIA, DOE developed an alternative NIA model where shipments in the policy case do not account for any consumer-choice decision making. DOE believes that the national benefits from standards calculated this way are more comparable to the benefits from the alternative policies.
[b] For this RIA, DOE analyzed the gas-fired commercial warm air furnaces equipment class of CWAFs as it makes up the majority of the market.

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 CWAFs. 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. Appendix17A discusses the NIA-RIA integrated model approach.

DOE quantified the effect of each alternative on the purchase of equipment that meet the efficiency levels of their corresponding target levels set for each TSL.[c] 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 levels. 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 equipment that did not meet the target levels in the base case,[d] 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 CWAFs attributable to each policy alternative.

Increasing the efficiency of equipment 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 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 primary energy saved over the lifetime of equipment purchased during the analysis period starting in the effective date of the policy. The analysis period is 2023-2048 for the selected TSL (TSL 2), and 2019-2048 for the remaining TSLs.

[c] The target levels refer to the efficiency level set for each equipment class at each TSL.
[d] The base case for the NIA is a market-weighted average energy efficiency calculated from units at several efficiency levels.

- Net Present Value (NPV), represents the value of net monetary savings in 2015, expressed in 2014$, from equipment purchased during the analysis period starting in the effective date of the policy. DOE calculated the NPV as the difference between the present value of installed equipment cost and operating expenditures in the base case and the present value of those costs in each policy case. DOE calculated operating expenses (including energy costs) for the life of equipment.

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' responses 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 meet 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 CWAFs relative to their base 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 efficiency levels as the target levels of 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 levels.

Table 17.2.1 shows the efficiency level stipulated for gas-fired CWAFs in the proposed TSLs.

Table 17.2.1 Efficiency Levels for Trial Standard Levels for Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
	1, 2	**3, 4**	**5**
Efficiency Level	1	2	3
Energy Efficiency (TE)	81%	82%	91%

DOE assumed that the effects of non-regulatory policies would last from the effective date of standards for each TSL (2019 or 2023, depending on the TSL), through the end of the analysis period (2048).

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 not additive; 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 the CWAF equipment class covered by this RIA.

17.3 NON-REGULATORY POLICY ASSUMPTIONS

The following subsections describe DOE's analysis of the impacts of the six non-regulatory policy alternatives to the proposed standards for CWAFs. (Because the alternative of No New Regulatory Action has no energy or economic impacts, essentially representing the NIA base case, DOE did not perform any additional analysis for that alternative.) DOE developed estimates of the market penetration of high-efficiency equipment 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 CWAFs constitutes the base case, as described in chapter 10, National Impact Analysis. The base 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 appliances. This policy provides a consumer rebate for purchasing CWAFs that operate at the same efficiency as the target levels 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.,[e] summarized experiences with various utility rebate programs.[1] XENERGY's analytical method utilized graphs, or penetration curves, that estimate the market penetration of a

[e] XENERGY is now owned by KEMA, Inc. (www.kema.com)

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 analysis 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. *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. Appendix17A 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 CWAFs by determining, for each TSL, the increase in market penetration of equipment meeting the target level relative to their market penetration in the base case. It used the interpolation method presented in Blum et al (2011)[9] to create customized penetration curves based on relationships between actual base 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 CWAFs. 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 commercial gas furnaces so they can best reflect the market barrier level faced by the specified equipment class. Section 17.3.2.2 shows the interpolated curves used in the analysis.

17.3.2.2 Analysis

For the CWAF equipment class it analyzed, DOE estimated the effect of increasing its B/C ratio via a rebate that would pay all of the increased installed cost of a unit that met the

target efficiency level compared to one meeting the baseline efficiency level.[f] To inform its estimate of an appropriate rebate amount, DOE performed a thorough nationwide search for existing rebate programs for CWAFs. DOE was able to identify one utility rebate program that offered three rebates for CWAFs, which would cover all of the increased installed cost.[g] As a consequence, DOE used the increased installed cost for each TSL to represent its corresponding rebate level. DOE assumed that rebates would remain in effect at the same levels throughout the forecast period (2019 or 2023, depending on the TSL).

For the analyzed CWAF equipment class, DOE first calculated the B/C ratio without a rebate using the difference in total installed costs (C) and lifetime operating cost savings (B) between the unit meeting the target level and the 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 on the B/C ratio for each TSL.

Table 17.3.1 Benefit/Cost Ratios Without and With Rebates for Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
Commercial Gas Furnace	1, 2	3, 4	5
B/C Ratio Without Rebate	8.4	1.0	1.1
Rebate Amount (2014$)	27.14	455.89	1752.75
B/C Ratio With Rebate[h]	infinite	infinite	infinite
Calculated Market Barriers Curve	Mod-High**	Mod-High	Mod

** Mod: Moderate market barriers; Mod-High: Moderate-to-High market barriers

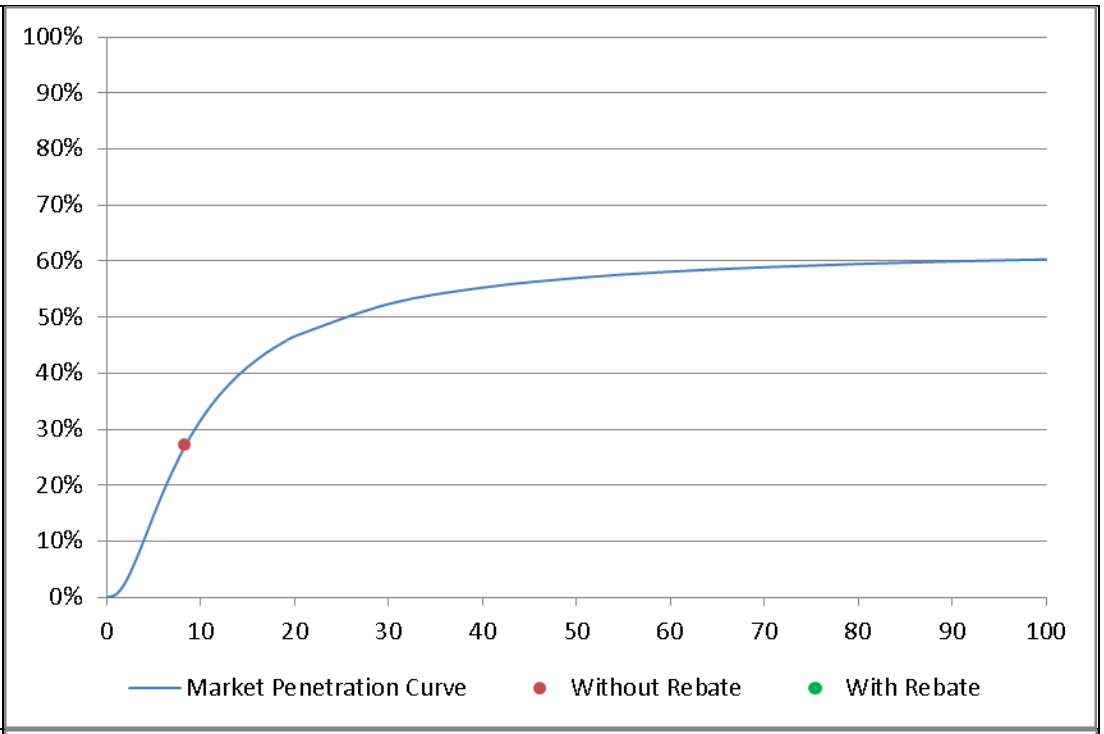
DOE used these B/C ratios along with the penetration curves shown in Figure 17.3.1 to estimate the percentage of consumers who would purchase CWAFs that meet the target level both with and without a rebate incentive. The penetration curves calculated by DOE to represent the market behavior for gas-fired CWAFs at each TSL are indicated in Table 17.3.1.

[f] The baseline technology for each equipment class is defined in the engineering analysis, Chapter 5, as the technology that represents the basic characteristics of products in that class. A baseline unit typically is one that just meets current Federal energy conservation standards and provides basic consumer utility.

[g] New York utility, Consolidated Edison of New York (Con Edison), offers rebates for "High Efficiency Gas Furnaces with ECM (electronically commutated motor)" to its natural gas customers. The rebates are offered at the following values: $750, $1,500, $2,500.

[h] Because the rebate value covers the whole additional equipment cost, incremental costs for all TSLs turn into zero and the corresponding benefit-cost ratios after the rebate tend to infinite.

TSL 1, 2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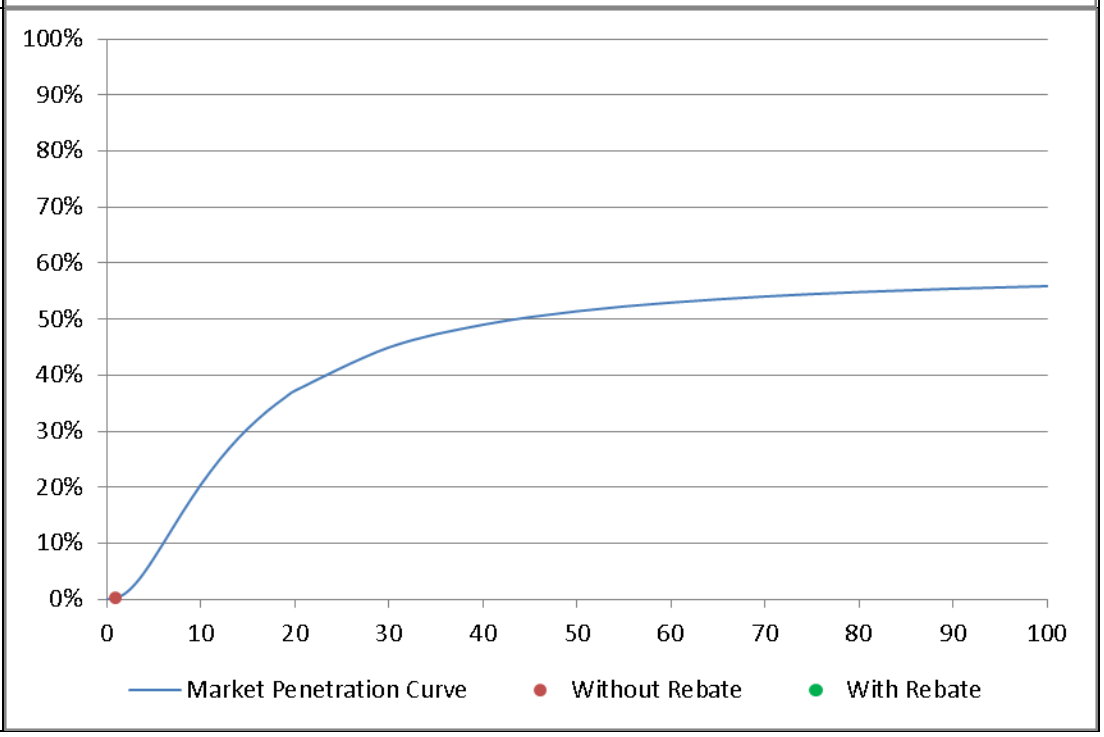
Market Penetration Curve
Without Rebate
With Rebate

TSL 3, 4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Market Penetration Curve
Without Rebate
With Rebate

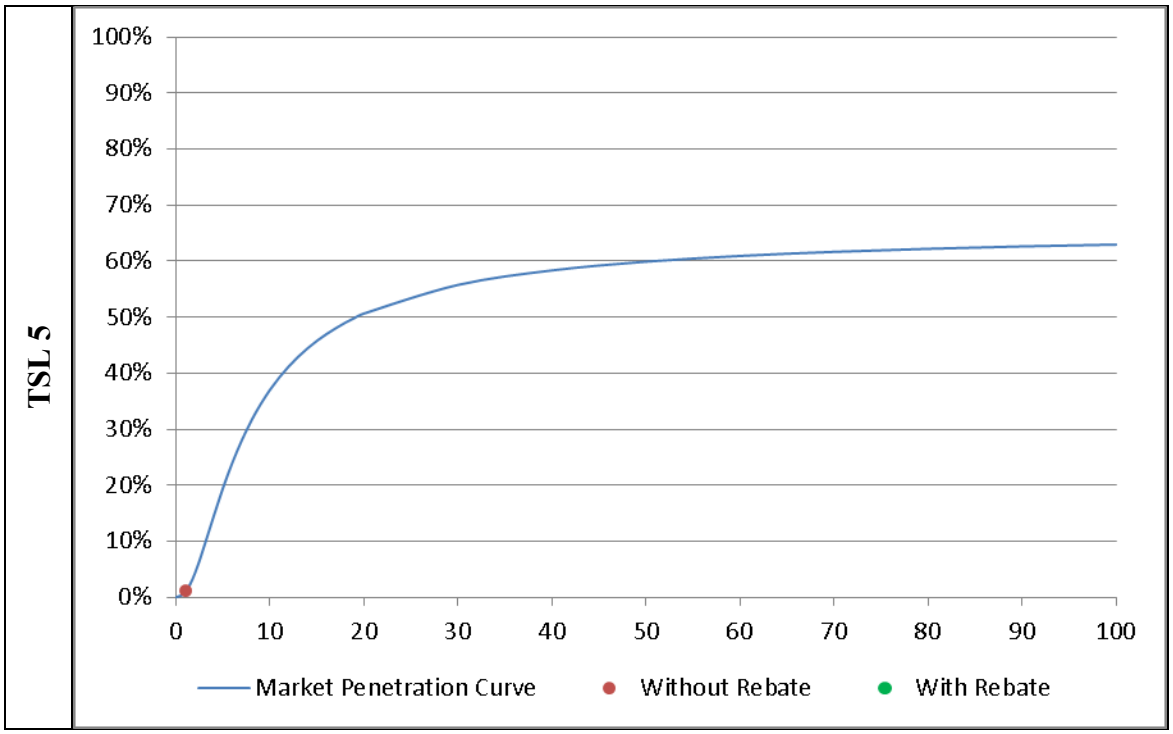

Figure 17.3.1 Market Penetration Curves for Gas-Fired Commercial Warm Air Furnaces[i]

DOE next estimated the percent increases 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 base 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 CWAFs regarding the market penetration of equipment in effective date of standards (2019 or 2023, depending on the TSL) that meet the target efficiency level at each TSL given a consumer rebate.

Table 17.3.2 Market Penetrations in the Effective Year of Standards Attributable to Consumer Rebates for Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
Commercial Gas Furnace	1, 2	3, 4	5
Base-Case Market Share	27.1%	0.2%	1.1%
Policy Case Market Share	63.3%	59.4%	65.8%
Increased Market Share	36.2%	59.2%	64.7%

DOE used the resulting annual increases in market shares as inputs to represent the rebate policy case scenario in its NIA-RIA model. Appendix17A shows the annual market share

[i] Because the B/C ratio with rebates is infinite (see Table 17.3.1), the data points that refer to the market penetration with rebates for each TSL are not shown in the charts.

increases due to this policy. Section 17.4 presents the resulting market penetration trends for the policy case of consumer rebates for gas-fired CWAFs.

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.[11, 12] 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.[13]

In preparing its assumptions to estimate the effects of tax credits on consumer purchases of gas-fired CWAFs 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.[14] 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.[15, 16] 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.[17] 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 CWAFs to warrant adjusting its analysis method for the Consumer Tax Credits policy case. Appendix17A 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.[18] 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 appendix17A.

DOE applied the assumed 60 percent participation described above to the 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 penetration curves selected for CWAFs.

Table 17.3.3 summarizes DOE's assumptions for CWAFs regarding the market penetration of units in the effective year of standards (2019 or 2023, depending on the TSL) that meet the efficiency level at each TSL given a consumer tax credit.

Table 17.3.3 Market Penetrations in the Effective Year of Standards Attributable to Consumer Tax Credits for Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
Commercial Gas Furnace	1, 2	3, 4	5
Base-Case Market Share	27.1%	0.2%	1.1%
Policy Case Market Share	48.8%	35.7%	40.0%
Increased Market Share	21.7%	35.5%	38.8%

The increased market shares attributable to consumer tax credits shown in Table 17.3.3 were used as inputs in the NIA-RIA model. Appendix17A shows the annual market share increases due to this policy. Section 17.4 presents the resulting market penetration trends for the policy case of consumer tax credits for gas-fired CWAFs that meet the efficiency level for each TSL.

17.3.4 Manufacturer Tax Credits

To analyze the potential effects of a policy that offers tax credits to manufacturers that produce CWAFs that meet the target efficiency level 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.[j] Because the direct price effect is approximately equivalent to the announcement effect,[11] 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 equipment. 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.[19] 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. Appendix17A presents details on Federal manufacturer tax credits.

DOE applied the assumption of 30 percent participation to the penetration rates predicted for the rebate policy to estimate the effects of a manufacturer tax credit policy. In doing so, the Department incorporated the assumptions for consumer response to financial incentives from the penetration curves calculated for gas-fired CWAFs.

Table 17.3.4 summarize DOE's assumptions for gas-fired CWAFs regarding the market penetration of units in the effective year of standards (2019 or 2023, depending on the TSL) meeting the efficiency level at each TSL given a manufacturer tax credit.

Table 17.3.4 Market Penetrations in the Effective Year of Standards Attributable to Manufacturer Tax Credits for Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
Commercial Gas Furnace	1, 2	3, 4	5
Base-Case Market Share	27.1%	0.2%	1.1%
Policy Case Market Share	38.0%	18.0%	20.6%
Increased Market Share	10.8%	17.7%	19.4%

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. Appendix17A shows the annual market share increases due to this policy. Section 17.4 presents the resulting market penetration trends for the policy case of manufacturer tax credits for gas-fired CWAFs.

17.3.5 Voluntary Energy Efficiency Targets

For each equipment class, DOE assumed that voluntary energy efficiency targets would be achieved as manufacturers gradually stopped producing units that operated below the

[j] 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.

efficiency level set for each TSL. DOE assumed that the impetus for phasing out production of low-efficiency units would be a program similar to 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.[20, 21, 22]

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 equipment over time. During the rebate analysis, when assessing the B/C ratio and market penetration in the base case for each equipment class, DOE observed that the market barriers for gas-fired CWAFs range from moderate to a high level of barriers. DOE estimates that voluntary energy efficiency targets could reduce these barriers to lower levels over 10 years, and followed the methodology presented by Blum et al (2011)[9] to evaluate the effects that such a reduction in market barriers have on the market penetration of this equipment. 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 summarizes DOE's assumptions for gas-fired CWAFs regarding the market penetration of units in the effective year of standards (2019 or 2023, depending on the TSL) that meet the efficiency level at each TSL given voluntary energy efficiency targets.

Table 17.3.5 Market Penetrations in the Effective Year of Standards Attributable to Voluntary Energy Efficiency Targets for Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
Commercial Gas Furnace	1, 2	3, 4	5
Base-Case Market Share	27.1%	0.2%	1.1%
Policy Case Market Share	28.7%	0.3%	1.2%
Increased Market Share	1.6%	0.1%	0.1%

The increased market shares attributable to voluntary energy efficiency targets shown in Table 17.3.5 were used as inputs in the NIA-RIA model. Appendix17A shows the annual market share increases due to this policy. Section 17.4 presents the resulting market penetration trends for the policy case of voluntary energy efficiency targets for gas-fired CWAFs that meet the efficiency level for each TSL.

17.3.6 Bulk Government Purchases

Bulk government purchases can lead to Federal, State, and local governments purchasing large quantities of equipment that meet the target efficiency level. Combining the market demands of multiple public sectors also can provide a market signal to manufacturers and vendors that some of their largest customers seek equipment 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 equipment.

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 equipment. 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.[23, 24]

DOE assumed that government agencies would administer bulk purchasing programs for CWAFs. Currently, there is no FEMP program available for CWAFs. 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 commercial clothes washers meeting target efficiency levels.

DOE assumed that bulk government purchases would affect the subset of federal government-owned commercial buildings heated by furnaces. This subset consists primarily of buildings used for offices, education and other services. DOE used the 2003 Commercial Buildings Energy Consumption Survey (CBECS 2003)[26] to calculate the share of floor space in

commercial buildings heated by furnaces that corresponds to federal government-owned buildings. The calculation resulted in 0.36 percent. DOE assumed that percentage as the share of the market to which this policy would apply.

DOE estimated that, starting in the effective year of standards (2019 or 2023, depending on the TSL), each year of a bulk government purchase policy would result in an increasing percent of shipments of government-purchased units beyond the base case would meet target efficiency levels. DOE estimated that within 10 years, bulk government purchasing programs would result in 80 percent of the CWAF market for federal government-owned commercial buildings meeting the target level. DOE modeled the bulk government purchase program assuming that the market share for gas-fired CWAFs achieved in 10 years would be maintained throughout the rest of the analysis period.

Table 17.3.6 summarizes DOE's assumptions for gas-fired CWAFs regarding the market penetration of units in the effective year of standards that meet the efficiency level at each TSL given bulk government purchasing.

Table 17.3.6 Market Penetrations in the Effective Year of Standards Attributable to Bulk Government Purchasing of Gas-Fired Commercial Warm Air Furnaces

	Trial Standard Levels		
Commercial Gas Furnace	1, 2	3, 4	5
Base-Case Market Share	27.1%	0.2%	1.1%
Policy Case Market Share	27.1%	0.2%	1.2%
Increased Market Share	0.02%	0.03%	0.1%

The increased market shares attributable to bulk government purchasing shown in Table 17.3.6 were used as inputs in the NIA-RIA model. Appendix17A shows the annual market share increases due to this policy that DOE used as inputs to the NIA-RIA model. Section 17.4 below presents the resulting market penetration trends for the policy case of bulk government purchase of gas-fired CWAFs.

17.4 IMPACTS OF NON-REGULATORY ALTERNATIVES

Figure 17.4.1 shows the effects of each non-regulatory policy on market penetration of gas-fired CWAFs meeting the target level in the selected TSL (TSL 2). Relative to the base case, the policy cases increase the market shares that meet the target level. Recall the standards (not shown in the figures) would result in a 100-percent market penetration of equipment that meets the target efficiency level.

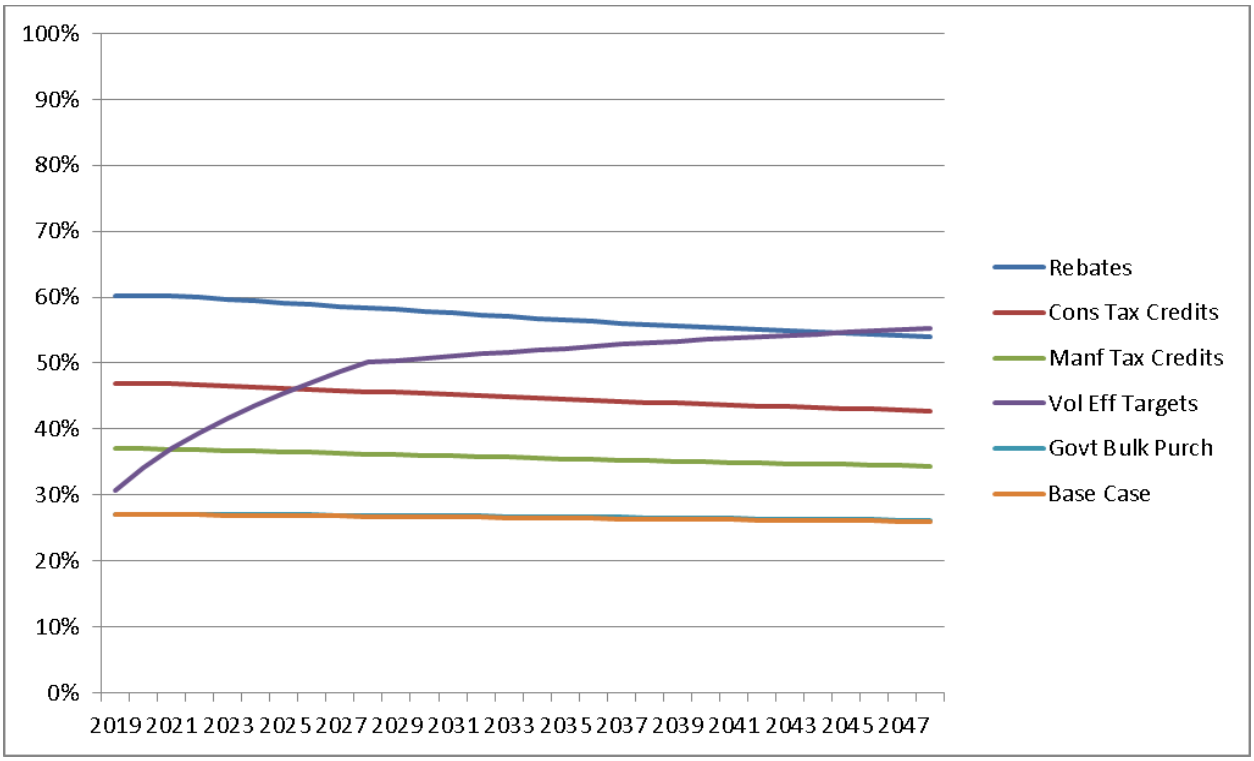

Figure 17.4.1 Market Penetration of Gas-Fired Commercial Warm Air Furnaces Meeting the Target Level in Policy Cases at TSL 2

Table 17.4.1 shows the national energy savings and net present value for five non-regulatory policies analyzed in detail for gas-fired CWAFs. The target level for each policy equals the efficiency level in the recommended TSL. The case in which no regulatory action is taken with regard to CWAFs constitutes the base case (or "No New Regulatory Action" scenario), in which NES and NPV are zero by definition. For comparison, the tables include the impacts from standards at the recommended TSL. Energy savings are given in quadrillion British thermal units (quads). The NPVs shown in Table 17.4.1 are based on two discount rates, 7 percent and 3 percent.

The policies with the highest projected cumulative energy savings and economic benefits are consumer rebates, followed by tax credits and voluntary energy efficiency targets. Results for government bulk purchases are not significant, as they are proportional to the very low share of floor space heated by furnaces in federal government owned buildings when compared to the floor space heated by furnaces across all commercial buildings.

Table 17.4.1 Impacts of Non-Regulatory Alternatives for Gas-Fired Commercial Warm Air Furnaces at TSL 2

Policy Alternative	Primary Energy Savings* quads		Net Present Value* billion 2014$	
			7% Discount Rate	3% Discount Rate
Consumer Rebates	0.092	(46.3%)**	156.0	434.0
Consumer Tax Credits	0.055	(27.8%)	93.6	260.4
Manufacturer Tax Credits	0.028	(13.9%)	46.8	130.2
Voluntary Energy Efficiency Targets	0.010	(4.9%)	7.1	46.1
Bulk Government Purchases	0.000	(0.0%)	0.1	0.2
Selected Standards†	0.199	(100.0%)	308.8	938.4

* For equipment shipped 2023 – 2048.
** The percentages show how the energy savings from each policy alternative compare to the primary energy savings from the selected standards (represented in the table as 100 percent).
† Includes only the effects of standards on gas-fired CWAFs shipped to commercial sector.

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APPENDIX 17A. REGULATORY IMPACT ANALYSIS: SUPPORTING MATERIALS

TABLE OF CONTENTS

17A.1 INTRODUCTION 17A-2
17A.2 MARKET SHARE ANNUAL INCREASES BY POLICY 17A-2
17A.3 NIA-RIA INTEGRATED MODEL 17A-4
17A.4 CONSUMER REBATE POLICY MARKET PENETRATION CURVES 17A-4
17A.4.1 Introduction 17A-4
17A.4.2 Adjustment of XENERGY Penetration Curves 17A-6
17A.4.3 Interpolation of Penetration Curves 17A-7
17A.5 FEDERAL AND STATE TAX CREDITS 17A-7
17A.5.1 Federal Tax Credits for Consumers 17A-7
17A.5.2 Federal Tax Credits for Manufacturers 17A-9
17A.5.3 State Tax Credits 17A-9

LIST OF TABLES

Table 17A.2.1 Annual Increases in Market Shares Attributable to Alternative Policy Measures for Gas-Fired Commercial Warm Air Furnaces 17A-3

LIST OF FIGURES

Figure 17A.4.1 S-Curves Showing Effects of External and Internal Sources on Adoption of New Technologies 17A-6

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;
- XENERGY penetration curves used to analyze consumer rebates, including:
    - Background material,
    - DOE's adjustment of these curves for this analysis, and
    - The method DOE used method for interpolating the curves; and
- Background material on Federal and state tax credits for appliances.

17A.2 MARKET SHARE ANNUAL INCREASES BY POLICY

Table 17A.2.1 shows the annual increases in market shares of commercial warm air furnaces (CWAF)[a] meeting the target efficiency level in the selected TSL (TSL 2). DOE used these market share increases as inputs to the NIA-RIA spreadsheet model.

[a] For this RIA, DOE only analyzed gas-fired CWAF, which represent more than 98 percent of CWAF shipments.

Table 17A.2.1 Annual Increases in Market Shares Attributable to Alternative Policy Measures for Gas-Fired Commercial Warm Air Furnaces

Year	Consumer Rebates	Consumer Tax Credits	Manufacturer Tax Credits	Voluntary Energy Efficiency Targets	Bulk Government Purchases
2023	32.7%	19.6%	9.8%	14.8%	0.1%
2024	32.5%	19.5%	9.7%	16.8%	0.1%
2025	32.2%	19.3%	9.7%	18.6%	0.1%
2026	32.0%	19.2%	9.6%	20.3%	0.2%
2027	31.8%	19.1%	9.5%	21.9%	0.2%
2028	31.6%	18.9%	9.5%	23.4%	0.2%
2029	31.4%	18.8%	9.4%	23.7%	0.2%
2030	31.2%	18.7%	9.3%	24.0%	0.2%
2031	30.9%	18.5%	9.3%	24.4%	0.2%
2032	30.7%	18.4%	9.2%	24.8%	0.2%
2033	30.4%	18.3%	9.1%	25.1%	0.2%
2034	30.2%	18.1%	9.1%	25.4%	0.2%
2035	30.0%	18.0%	9.0%	25.8%	0.2%
2036	29.8%	17.9%	8.9%	26.1%	0.2%
2037	29.6%	17.8%	8.9%	26.4%	0.2%
2038	29.4%	17.7%	8.8%	26.7%	0.2%
2039	29.3%	17.6%	8.8%	27.0%	0.2%
2040	29.1%	17.5%	8.7%	27.2%	0.2%
2041	28.9%	17.4%	8.7%	27.5%	0.2%
2042	28.8%	17.3%	8.6%	27.7%	0.2%
2043	28.7%	17.2%	8.6%	28.0%	0.2%
2044	28.5%	17.1%	8.6%	28.3%	0.2%
2045	28.4%	17.0%	8.5%	28.5%	0.2%
2046	28.2%	16.9%	8.5%	28.8%	0.2%
2047	28.1%	16.8%	8.4%	29.0%	0.2%
2048	27.9%	16.8%	8.4%	29.3%	0.2%

17A.3 NIA-RIA INTEGRATED MODEL

For this analysis, DOE used its integrated NIA-RIA model approach that built on a modified version of the NIA model discussed in chapter 10 and documented in appendix 10A. The resulting integrated NIA-RIA model featured both the NIA analysis inputs and results and the RIA inputs and had the capability to generate results for each of the RIA policies at each TSL. A separate module produced results summaries for the tables and figures in the RIA document. For the RIA methodology documentation in chapter 17, the module created summaries of parameters calculated by the model for the consumer rebates policy, generated its penetration curves (discussed in section 17A.4.3 below), and reported market share impacts by equipment class for each alternative policy included in this RIA. For the RIA results reported in chapter 17, the module produced graphs of the market share increases resulting from each of the policies analyzed and created summary tables for the national energy savings (NES) and net present value (NPV) results. This module also generated tables of annual market share increases for each policy reported in section 17A.2 of this appendix.

17A.4 CONSUMER REBATE POLICY MARKET PENETRATION CURVES

This section first discusses the theoretical basis for the market penetration curves that DOE used to analyze the Consumer Rebates policy. 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 each specific equipment class and efficiency level in the analysis. The resulting curves for CWAF equipment classes are in chapter 17.

17A.4.1 Introduction

XENERGY, Inc.,[b] 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

[b] XENERGY is now owned by KEMA, Inc. (www.kema.com)

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 by internal sources of information, the number of adopters increases gradually, forming a convex curve (the logistic curve in Figure 17A.4.1).

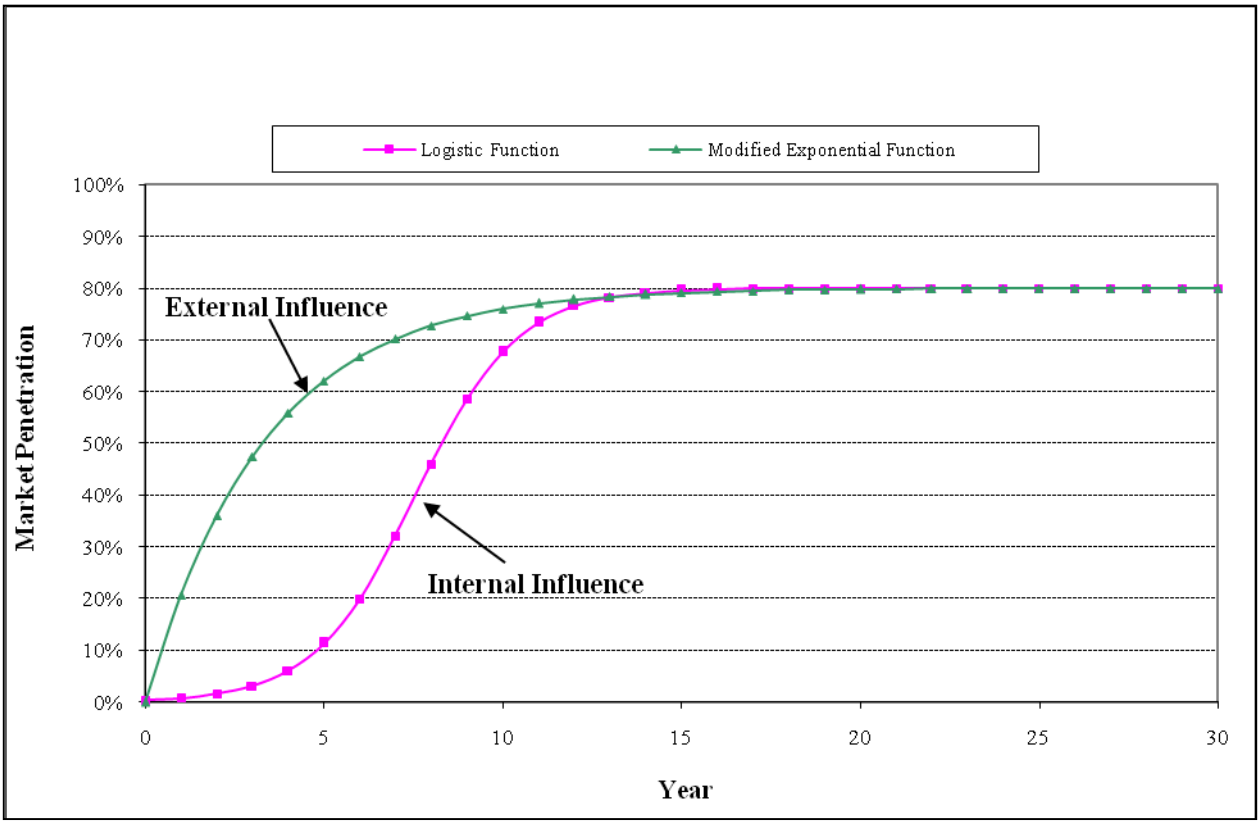

Figure 17A.4.1 S-Curves Showing Effects of External and Internal Sources on Adoption of New Technologies

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.[c] 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.[d] 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.

17A.5 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.

17A.5.1 Federal Tax Credits for Consumers

The Energy Policy Act of 2005 (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,

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[c] Chapter 17 refers to these curves as *penetration curves*. This section, in references to the original source, uses the term *implementation curve*.

[d] 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 can be considered proportional to the rebate impacts.

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 distributor 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 equipment class. 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.5.2 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.5.3 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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