CHAPTER 1. INTRODUCTION

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CHAPTER 1. INTRODUCTION

1.1 DOCUMENT PURPOSE

This technical support document (TSD) is a stand-alone report that presents the technical analyses that the U.S. Department of Energy (DOE or Department) has conducted in preparation for amending energy conservation standards for liquid-immersed, low-voltage dry-type, and medium-voltage dry-type distribution transformers. The public is invited to comment on these analyses, either in writing or orally at a public meeting on February 23, 2012. Details about the public meeting and instructions for submitting written comments are contained in the notice of public rulemaking (NOPR) published in the *Federal Register* on XXXX, 2012. XX FR XXXXX. DOE will review the comments it receives and revise and update these analyses prior to publishing a final rule in the *Federal Register*.

1.2 HISTORY OF DISTRIBUTION TRANSFORMER RULEMAKINGS

Title III, Part C of the Energy Policy and Conservation Act of 1975 (EPCA), Pub. L. 94-163 (42 U.S.C. 6311-6317, as codified), added by Pub. L. 95-619, Title IV, § 441(a), established the Energy Conservation Program for Certain Industrial Equipment, a program covering distribution transformers, the focus of this notice.[1] EPCA, as amended by the Energy Policy Act of 1992, Pub. L. 102-486, directs DOE to prescribe energy conservation standards for those distribution transformers for which the Secretary of Energy (Secretary) determines that standards "would be technologically feasible and economically justified, and would result in significant energy savings." (42 U.S.C. 6317(a)) DOE issued a final rule in 2007 that prescribed standards for distribution transformers. 72 FR 58190 (October 12, 2007) (the 2007 final rule); see 10 CFR 431.196(b)-(c).

During the course of the 2007 rulemaking for distribution transformers, the Energy Policy Act of 2005 (EPACT 2005), Pub. L. 109–58, amended EPCA to set standards for low-voltage dry-type (LVDT) distribution transformers. (EPACT 2005, Section 135(c); codified at 42 U.S.C. 6295(y)) Consequently, DOE removed these transformers from the scope of that rulemaking. 72 FR at 58191 (October 12, 2007).

After publication of the 2007 final rule, certain parties filed petitions for review in the United States Courts of Appeals for the Second and Ninth Circuits, challenging the final rule, and several additional parties were permitted to intervene in support of these petitions. (All of these parties are referred to below collectively as "petitioners.") The petitioners alleged that, in developing energy conservation standards for distribution transformers, DOE did not comply with certain applicable provisions of EPCA and of the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321 *et seq*. DOE and the petitioners subsequently entered into a settlement agreement to resolve that litigation. The settlement agreement outlined an expedited

[1] For editorial reasons, upon codification in the U.S. Code, Part C was re-designated Part A-1.

timeline for the Department to determine whether to amend the energy conservation standards for liquid-immersed and MVDT distribution transformers. Under the original terms of the settlement agreement, DOE must publish by October 1, 2011 either a determination that the standards for these distribution transformers do not need to be amended or a notice of public rulemaking (NOPR) that includes any new proposed standards and that meets all applicable requirements of EPCA and NEPA. However, due to an amendment to the settlement agreement, the October 1, 2011, deadline for a DOE determination or NOPR was extended to February 1, 2012. If DOE finds that amended standards are warranted, DOE must publish a final rule containing such amended standards by October 1, 2012. This document is the technical details supporting the Department's first step to satisfy the requirements of the settlement agreement.

DOE initiated this rulemaking at the preliminary analysis stage rather than the framework document stage. In considering new or amended standards for a given product or type of equipment, DOE's historic practice, generally, is to publish a framework document as the first step in the rulemaking process, and to subsequently issue a preliminary TSD that contains the Department's preliminary analyses as to potential standards. The framework document generally advises interested parties of the analytical methods, data sources, and key assumptions DOE plans to use in considering the adoption of standards for the product or equipment type. Typically the document does not contain any analysis of the data.

On November 16, 2010, DOE announced a number of steps meant to streamline its regulatory process. Among these measures was the concept that, in appropriate circumstances, DOE might forego certain preliminary stages of the rulemaking process and gather data in more efficient ways. Because the previous rulemaking to develop standards for distribution transformers was completed in 2007, DOE has a set of methodologies, data sources and assumptions that have recently been vetted and revised according to public comments that the Department can use to perform the analyses needed for this rulemaking. Therefore, while DOE will conduct the analyses referenced by the petitioners' complaint and required by EPCA and NEPA according to standard practices for energy conservation standard rulemakings, DOE is not issue a framework document for this rulemaking. Rather, DOE initiated this rulemaking at the preliminary analysis stage and prepared a preliminary TSD about which it requested comment and used when developing this revised TSD for the NOPR.

At present, DOE plans to amend standards for LVDT distribution transformers, as well as amend standards for liquid-immersed and MVDT transformers. DOE is not required to consider LVDT distribution transformers as part of the settlement agreement. As such, DOE may subsequently opt to conduct a separate rulemaking for LVDT transformers with a different timeline. However, the NOPR considers LVDT distribution transformers along with liquid-immersed and MVDT distribution transformers.

On July 29, 2011, DOE published in the Federal Register a notice of intent to establish a subcommittee under the Energy Efficiency and Renewable Energy Advisory Committee (ERAC), in accordance with the Federal Advisory Committee Act and the Negotiated Rulemaking Act, to negotiate proposed Federal standards for the energy efficiency of medium-voltage dry-type and liquid immersed distribution transformers. 76 FR 45471. . Stakeholders strongly supported a consensual rulemaking effort. DOE believed that, in this case, a negotiated rulemaking would result in a better informed NOPR and would minimize any potential negative impact of the NOPR. On August 12, 2011, DOE published in the Federal Register a similar notice of intent to negotiate proposed Federal standards for the energy efficiency of low-voltage dry-type distribution transformers. 76 FR 50148. The purpose of the subcommittee was to discuss and, if possible, reach consensus on a proposed rule for the energy efficiency of distribution transformers.

The ERAC subcommittee for medium-voltage liquid-immersed and dry-type distribution transformers consisted of representatives of parties having a defined stake in the outcome of the proposed standards, listed below.

- ABB Inc.
- AK Steel Corporation
- American Council for an Energy-Efficient Economy
- American Public Power Association
- Appliance Standards Awareness Project
- ATI-Allegheny Ludlum
- Baltimore Gas and Electric
- Cooper Power Systems
- Earthjustice
- Edison Electric Institute
- Fayetteville Public Works Commission
- Federal Pacific Company
- Howard Industries Inc.
- LakeView Metals
- Lawrence Berkeley National Laboratory
- Metglas, Inc.
- National Electrical Manufacturers Association
- National Resources Defense Council
- National Rural Electric Cooperative Association
- Northwest Power and Conservation Council
- Pacific Gas and Electric Company
- Progress Energy
- Prolec GE
- U.S. Department of Energy

The ERAC subcommittee for medium-voltage liquid-immersed and dry-type distribution transformers held meetings on September 15 through 16, 2011, October 12 through 13, 2011, November 8 through 9, 2011, and November 30 through December 1, 2011; the ERAC subcommittee also held public webinars on November 17 and December 14. During the course of the September 15, 2011, meeting, the subcommittee agreed to its rules of procedure, ratified its schedule of the remaining meetings, and defined the procedural meaning of consensus. The subcommittee defined consensus as unanimous agreement from all present subcommittee members. Subcommittee members were allowed to abstain from voting for an efficiency level; their votes counted neither toward nor against the consensus.

DOE presented its draft engineering, life-cycle cost and national impacts analysis and results. During the meetings of October 12 through 13, 2011, DOE presented its revised analysis and heard from subcommittee members on a number of topics. During the meetings on November 8 through 9, 2011, DOE presented its revised analysis, including life-cycle cost sensitivities based on exclusion ZDMH and amorphous steel as core materials. During the meetings on November 30 through December 1, 2011, DOE presented its revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their efficiency level recommendations. For medium-voltage liquid-immersed distribution transformers, the advocates, represented by the Appliance Standards Awareness Project (ASAP), recommended efficiency level (also referred to as "EL") 3 for all design lines (also referred to as "DLs"). The National Electrical Manufacturers Association (NEMA) and AK Steel recommended EL 1 for all DLs except for DL 2, for which no change from the current standard was recommended. Edison Electric Institute (EEI) and ATI Allegheny Ludlum recommended EL1 for DLs 1, 3, and 4 and no change from the current standard or a proposed standard of less than EL 1 for DLs 2 and 5. Therefore, the subcommittee did not arrive at consensus regarding proposed standard levels for medium-voltage liquid-immersed distribution transformers.

For medium-voltage dry-type distribution transformers, the subcommittee arrived at consensus and recommended a proposed standard of EL2 for DLs 11 and 12, from which the proposed standards for DLs 9, 10, 13A, 13B would be scaled.

The ERAC subcommittee held meetings on September 28, 2011, October 13-14, 2011, November 9, 2011, and December 1-2, 2011, for low-voltage distribution transformers. The ERAC subcommittee also held webinars on November 21, 2011, and December 20, 2011. During the course of the September 28, 2011, meeting, the subcommittee agreed to its rules of procedure, finalized the schedule of the remaining meetings, and defined the procedural meaning of consensus. The subcommittee defined consensus as unanimous agreement from all present subcommittee members. Subcommittee members were allowed to abstain from voting for an efficiency level; their votes counted neither toward nor against the consensus.

The ERAC subcommittee for low-voltage distribution transformers consisted of representatives of parties having a defined stake in the outcome of the proposed standards.

- AK Steel Corporation
- American Council for an Energy-Efficient Economy
- Appliance Standards Awareness Project
- ATI-Allegheny Ludlum
- EarthJustice
- Eaton Corporation
- Federal Pacific Company

- Lakeview Metals
- Lawrence Berkeley National Laboratory
- Metglas, Inc.
- National Electrical Manufacturers Association
- Natural Resources Defense Council
- ONYX Power
- Pacific Gas and Electric Company
- Schneider Electric
- U.S. Department of Energy

DOE presented its draft engineering, life-cycle cost and national impacts analysis and results. During the meetings of October 14, 2011, DOE presented its revised analysis and heard from subcommittee members on various topics. During the meetings of November 9, 2011, DOE presented its revised analysis. During the meetings of December 1, 2011, DOE presented its revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their energy efficiency level recommendations. For low-voltage dry-type distribution transformers, the advocates, represented by ASAP, recommended EL4 for all DLs, NEMA recommended EL 2 for DLs 7 and 8, and no change from the current standard for DL 6. EEI, AK Steel and ATI Allegheny Ludlum recommended EL 1 for DLs 7 and 8, and no change from the current standard for DL 6. The subcommittee did not arrive at consensus regarding a proposed standard for low-voltage dry-type distribution transformers.

1.3 PROCESS FOR SETTING ENERGY CONSERVATION STANDARDS

Under EPCA, when DOE studies new or amended standards, it must consider, to the greatest 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 compared to any increase in the prices, initial costs, or maintenance expenses 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 covered 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. 6295(o)(2)(B)(i))

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

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. Beginning with the preliminary analysis for this rulemaking and during subsequent comment periods, interactions among interested parties provide a balanced discussion of the information that is required for the standards rulemaking.

Before DOE determines whether to adopt an amended 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. 6295 (o)(2)(B)(i))

After the publication of the preliminary analysis NOPM, the energy conservation standards rulemaking process involves two additional public notices that DOE publishes in the *Federal Register*. This first step of the rulemaking notices is a NOPM, which is designed to publicly vet the models and tools used in the preliminary rulemaking and to facilitate public participation before the NOPR stage. The next notice is the NOPR, which presents a discussion of comments received in response to the NOPM and the preliminary analyses and analytical tools; analyses of the impacts of potential new or amended energy conservation standards on customer, manufacturers, and the Nation; DOE's weighting of these impacts; and the proposed energy conservation standards for each equipment class. The last notice is the final rule, which presents a discussion of the comments received in response to the NOPR, the revised analyses, DOE's weighting of these impacts, the amended energy conservation standards DOE is adopting for each product, and the effective dates of the amended energy conservation standards.

The analytical framework presented in this TSD presents the different analyses, such as the engineering analysis and the consumer economic analyses (*e.g.*, the life-cycle cost (LCC) and payback period (PBP) analyses), the methods used for conducting them, and the relationships among the various analyses. Table 1.3.1 outlines the analyses DOE conducts for each stage of the rulemaking.

Table 1.3.1 Analyses by Rulemaking Stage

	Preliminary	NOPR	Final Rule
Market and technology assessment	✓	✓	✓
Screening analysis	✓	✓	✓
Engineering analysis	✓	✓	✓
Energy use characterization	✓	✓	✓
Product price determination	✓	✓	✓
Life-cycle cost and payback period analyses	✓	✓	✓
Life-cycle cost subgroup analysis		✓	✓
Shipments analysis	✓	✓	✓
National impact analysis	✓	✓	✓
Preliminary manufacturer impact analysis	✓		
Manufacturer impact analysis		✓	✓
Utility impact analysis		✓	✓
Employment impact analysis		✓	✓
Environmental assessment		✓	✓
Regulatory impact analysis		✓	✓

DOE developed spreadsheets for the engineering, LCC, PBP, and national impact analyses (NIA) for each equipment class. The LCC workbook calculates the LCC and PBP at various energy efficiency levels. The NIA workbook does the same for national energy savings (NES) and national net present values (NPVs). All of these spreadsheets are available on the DOE website for distribution transformers:

http://www1.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html.

1.3.1 Manufacturer Interviews

As part of the information gathering and sharing process, DOE interviewed distribution transformer manufacturers. DOE selected companies that represented production of all types of equipment, ranging from small to large manufacturers. DOE had four objectives for these interviews: (1) solicit manufacturer feedback on the draft inputs to the engineering analysis; (2) solicit feedback on topics related to the manufacturer impact analysis; (3) provide an opportunity for manufacturers to express their concerns to DOE; and (4) foster cooperation between manufacturers and DOE. DOE incorporated the information gathered during these interviews into its engineering analysis (chapter 5) and its manufacturer impact analysis (chapter 12).

1.4 STRUCTURE OF THE DOCUMENT

The TSD describes the analytical approaches and data sources used in this rulemaking. The TSD consists of the following chapters and several appendices.

Chapter 1	Introduction: provides an overview of the appliance standards program and how it applies to the distribution transformer rulemaking, 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 analysis.
Chapter 3	Market and Technology Assessment: provides DOE's definition of a distribution transformer, lists the proposed equipment classes, and names the major industry players. This chapter also provides an overview of distribution transformer technology, including techniques employed to improve transformer efficiency.
Chapter 4	Screening Analysis: identifies all the design options that improve transformer efficiency, and determines which of these DOE evaluated and which DOE screened out of its analysis.
Chapter 5	Engineering Analysis: discusses the methods used for developing the relationship between increased manufacturer price and increased efficiency. Presents detailed cost and efficiency information for the units of analysis.
Chapter 6	Markups for Equipment Price Determination: discusses the methods used for establishing markups for converting manufacturer prices to customer equipment prices.
Chapter 7	Energy Use and End-Use Load Characterization: discusses the process used for generating energy-use estimates and end-use load profiles for distribution transformers.
Chapter 8	Life-Cycle Cost and Payback Period Analyses: describes the impact of potential candidate standards on customers of transformers. This chapter compares the life-cycle cost of transformers and other measures of consumer impact with and without candidate efficiency standards
Chapter 9	Shipments Analysis: discusses the methods used for forecasting the total number of distribution transformers that would be affected by standards.
Chapter 10	National Impact Analysis: discusses the methods used for forecasting national energy consumption and national consumer economic impacts in the absence and presence of standards.
Chapter 11	Life-Cycle Cost Subgroup Analysis: discusses the effects of standards on any identifiable subgroups of consumers who may be disproportionately affected by any proposed standard level. This chapter compares the LCC

and PBP of products with and without higher energy conservation standards for these consumers.

Chapter 12	Manufacturer Impact Analysis: discusses the effects of standards on the finances and profitability of transformer manufacturers.
Chapter 13	Employment Impact Analysis: discusses the effects of standards on national employment.
Chapter 14	Utility Impact Analysis: discusses the effects of standards on the electric utility industry.
Chapter 15	Emissions Analysis: discusses the effects of standards on air-borne emissions of electric utilities.
Chapter 16	Monetization of Emission Reductions Benefits: discusses the effects of standards on the monetary benefits likely to result from the reduced emissions of carbon dioxide (CO_2) and nitrogen oxides (NO_X).
Chapter 17	Regulatory Impact Analysis for Distribution Transformers: discusses the impact of non-regulatory alternatives to efficiency standards.

Appendices:

App. 3A	Core Steel Market Analysis: presents DOE's research into the global core steel market.
App. 5A	Additional Engineering Analysis Results: presents scatter plots for each of the 13 design lines, illustrating no-load losses versus manufacturer selling price (MSP); load losses versus MSP; and transformer weight versus efficiency.
App. 5B	Scaling Relationships in Transformer Manufacturing: discusses the technical basis of the 0.75 scaling rule.
App. 5C	2008 Material Pricing Analysis: presents the material prices DOE developed for studying sensitivities in material prices. This includes the material prices themselves and the engineering analysis plots.
App. 7A	Technical Aspects of Energy Use and End-Use Load Characterization: Details the methodology used to estimate transformer energy use and load simulation.
App. 7B	Sample Utilities: details the specific electric utilities for which DOE collected electricity marginal price and electric system loads.

App. 8A	User Instructions for Life-Cycle Cost and Payback Period Spreadsheet Model.
App. 8B	Uncertainty and Variability: provides an overview of the treatment of uncertainty and variability in the analysis.
App. 8C	Life-Cycle Cost and Payback Period Results: presents LCC and PBP results for all 13 design lines.
App. 8D	Life-Cycle Cost Sensitivity Results: presents the findings for the sensitivity analysis of design lines 1, 7 and 12 that result from changing key variables.
App. 10A	User Instructions for Shipments and National Impacts Analysis Spreadsheet Model
App. 10B	National Energy Savings and Net National Present Value Results: presents NES and NPV results for all product classes.
App 10C	National Impacts Analysis Sensitivity Analysis for Alternative Product Price Trends Scenarios: presents the results and analytic methodology used to estimate long-term distribution transformer pricing treds.
App. 12A	Manufacturer Impact Analysis Interview Guides: Liquid-immersed, low-voltage dry-type, and medium-voltage dry-type interview guides.
App. 16A	Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866: Estimates the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses
App. 17A	Regulatory Impact Analysis Supporting Material: provided background information on the marked penetration curves and utility rebated programs analyzed in the Regulatory Impact Analysis.

CHAPTER 2. ANALYTICAL FRAMEWORK

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CHAPTER 2. ANALYTICAL FRAMEWORK

2.1 INTRODUCTION

Section 6295(o)(2)(A) of 42 United States Code (U.S.C.) requires the U.S. Department of Energy (DOE) to set forth energy conservation standards that are technologically feasible and economically justified, and would achieve the maximum improvement in energy efficiency. This chapter provides a description of the general analytical framework that DOE uses in developing such standards. The analytical framework is a description of the methodology, the analytical tools, and relationships among the various analyses that are part of this rulemaking. For example, the methodology that addresses the statutory requirement for economic justification includes analyses of life-cycle cost (LCC), economic impact on manufacturers and users, national benefits, impacts, if any, on utility companies, and impacts, if any, from lessening competition among manufacturers.

Figure 2.1.1summarizes the stages and analytical components of the rulemaking process. The focus of this figure is the center column, which lists the analyses that DOE conducts. The figure shows how the analyses fit into the rulemaking process, and how they 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.

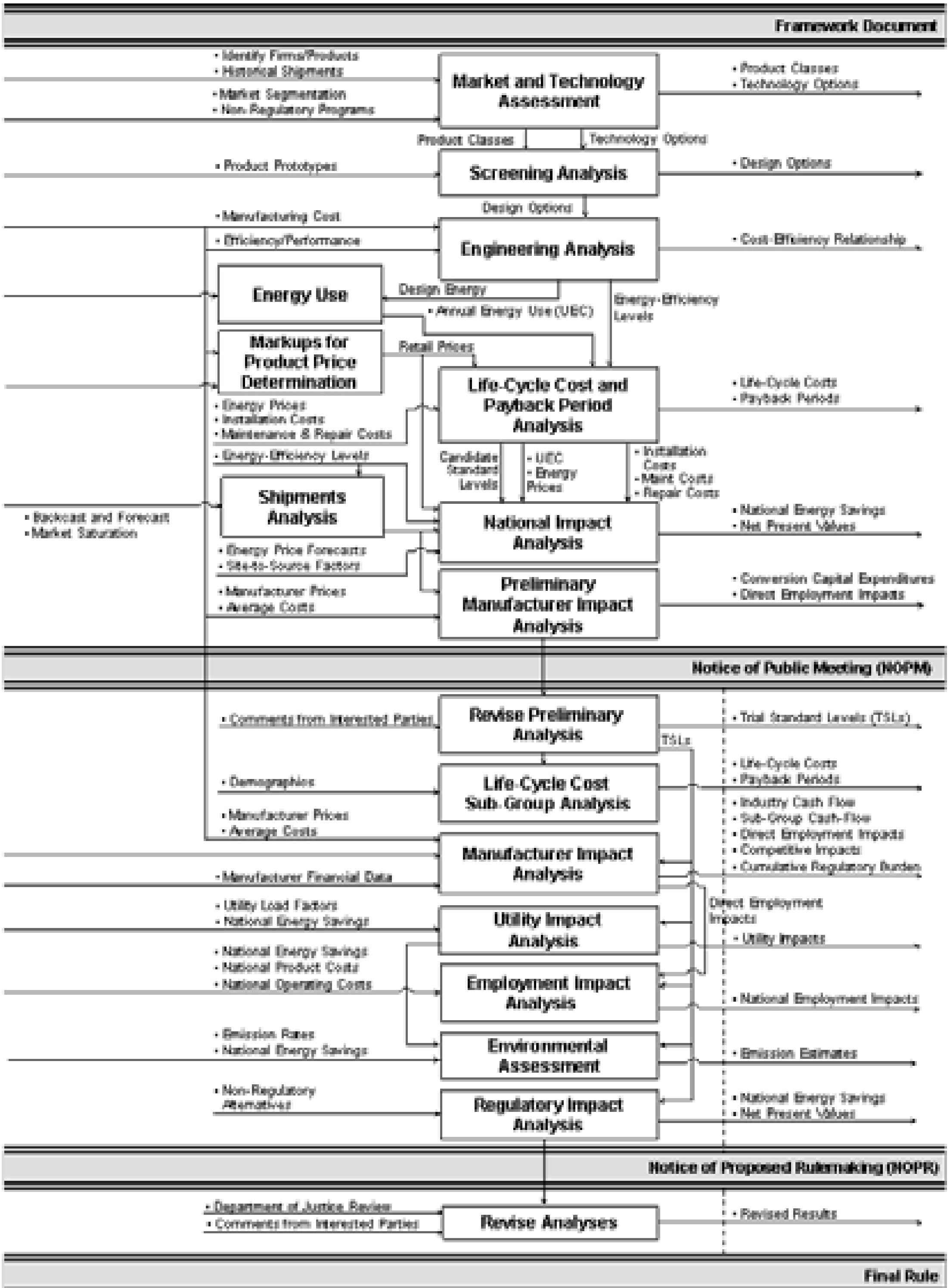

Figure 2.1.1 Flow Diagram of Analyses for the Energy Conservation Standards Rulemaking Analysis Process

The analyses performed prior to the notice of proposed rulemaking (NOPR) stage as part of the preliminary analyses and described in the preliminary technical support document (TSD) are listed below. These analyses were revised for the NOPR based in part on comments received, and are reported in this NOPR TSD. The analyses will be revised once again for the final rule based on any new comments or data received in response to the NOPR.

- A market and technology assessment to characterize the relevant equipment markets and existing technology options, including prototype designs.
- A screening analysis to review each technology option and determine if it is technologically feasible; is practical to manufacture, install, and service; would adversely affect equipment utility or equipment availability; or would have adverse impacts on health and safety.
- An engineering analysis to develop cost-efficiency relationships that show the manufacturer's cost of achieving increased efficiency.
- An energy use analysis to determine the annual energy use in the field of the considered equipment as a function of efficiency level.
- An LCC and payback period (PBP) analysis to calculate, at the consumer level, the relationship between savings in operating costs compared to any increase in the installed cost for equipment at higher efficiency levels.
- A shipments analysis to forecast equipment shipments, which then are used to calculate the national impacts of standards and future manufacturer cash flows.
- A national impact analysis (NIA) to assess the impacts at the national level of potential energy conservation standards for each of the considered equipment, as measured by the net present value (NPV) of total consumer economic impacts and the national energy savings (NES).
- A preliminary manufacturer impact analysis to assess the potential impacts of energy conservation standards on manufacturers, such as impacts on capital conversion expenditures, marketing costs, shipments, and research and development costs.

The additional analyses DOE performed for the NOPR stage of the rulemaking analysis include those listed below. DOE further revises the analyses for the final rule based on comments received in response to the NOPR.

- A consumer subgroup analysis to evaluate impacts of standards on particular consumer sub-populations, such as low-income households.

- A manufacturer impact analysis to estimate the financial impact of standards on manufacturers and to calculate impacts on competition, employment, and manufacturing capacity.

- An employment impact analysis to assess the indirect impacts of energy conservation standards on national employment.

- A utility impact analysis to estimate the effects of energy conservation standards on installed electricity generation capacity and electricity generation.

- An emissions analysis to provide estimates of the effects of energy conservation standards on emissions of carbon dioxide (CO_2), nitrogen oxides (NOx), and mercury (Hg) and to evaluate the monetary benefits likely to result from the reduced emissions of CO_2 and NO_x.

- A regulatory impact analysis to assess alternatives to energy conservation standards that could achieve substantially the same regulatory goal.

2.2 BACKGROUND

In a notice published on October 22, 1997 (62 FR 54809), DOE stated that it had determined that energy conservation standards were warranted for electric distribution transformers, relying in part on two reports by DOE's Oak Ridge National Laboratory (ORNL). These reports —Determination Analysis of Energy Conservation Standards for Distribution Transformers, ORNL-6847 (1996) and Supplement to the "Determination Analysis," ORNL-6847 (1997)—are available on the DOE website at: http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html. In 2000, DOE issued its Framework Document for Distribution Transformer Energy Conservation Standards Rulemaking, describing its proposed approach for developing standards for distribution transformers, and held a public meeting to discuss the Framework Document. The document is available on the above-referenced DOE website. Stakeholders also submitted written comments on the document, addressing a range of issues.

Subsequently, DOE issued draft reports as to certain of the key analyses contemplated by the Framework Document.[a] It received comments from stakeholders on these draft reports and, on July 29, 2004, published an advance notice of proposed rulemaking (ANOPR) for distribution transformer standards. 69 FR 45376. DOE then held a webcast on material it had published

[a] Copies of all the draft analyses published before the ANOPR are available on DOE's website: http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis.html.

relating to the ANOPR, followed by a public meeting on the ANOPR on September 28, 2004. In August 2005, DOE issued a draft of certain of the analyses on which it planned to base the standards for liquid-immersed and medium-voltage, dry-type distribution transformers, along with documents that supported the draft analyses.[b] DOE did this to enable stakeholders to review the analyses and make recommendations as to standard levels.

On April 27, 2006, DOE published its Final Rule on Test Procedures for Distribution Transformers. The rule: (1) established the procedure for sampling and testing distribution transformers so that manufacturers can make representations as to their efficiency, as well as establish that they comply with Federal standards; and (2) contained enforcement provisions, outlining the procedure the Department would follow should it initiate an enforcement action against a manufacturer. 71 FR 24972 (codified at 10 CFR 431.198).

On August 4, 2006, DOE published a NOPR in which it proposed energy conservation standards for distribution transformers (the 2006 NOPR). 71 FR 44355. Concurrently, DOE also issued a technical support document (TSD) that incorporated the analyses it had performed for the proposed rule, including several spreadsheets that remain available on DOE's website.[c]

Some commenters asserted that DOE's proposed standards might adversely affect replacement of distribution transformers in certain space-constrained (e.g., vault) installations. In response, DOE issued a notice of data availability and request for comments on this and another issue. 72 FR 6186 (Feb. 9, 2007) (the NODA). In the NODA, DOE sought comment on whether it should include in the LCC analysis potential costs related to size constraints of distribution transformers installed in vaults. DOE also outlined different approaches as to how it might account for additional installation costs for these space-constrained applications and requested comments on linking energy efficiency levels for three-phase liquid-immersed units with those of single-phase units. Finally, DOE addressed how it was inclined to consider a final standard that is based on energy efficiency levels derived from trial standard level (TSL) 2 and TSL 3 for three-phase units and TSLs 2, 3 and 4 for single-phase units. 72 FR 6189.. Based on comments on the 2006 NOPR, and the NODA, DOE created new TSLs to address the treatment of three-phase units and single-phase units. In October 2007, DOE published a final rule that created the current energy conservation standards for liquid-immersed and medium-voltage dry-type

[b] Copies of the four draft NOPR analyses published in August 2005 are available on DOE's website: http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis_nopr.html.

[c] The spreadsheets developed for this rulemaking proceeding are available at: http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers_draft_analysis_nopr.html.

distribution transformers. 72 FR 58190 (October 12, 2007) (the 2007 Final Rule) (codified at 10 CFR 431.196(b)-(c)).

The above paragraphs summarize development of the 2007 Final Rule. The preamble to the rule included additional, detailed background information on the history of that rulemaking. 72 FR 58194-96.

After the publication of the 2007 Final Rule, certain parties filed petitions for review in the United States Courts of Appeals for the Second and Ninth Circuits, challenging the rule. Several additional parties were permitted to intervene in support of these petitions. (All of these parties are referred to below collectively as "petitioners.") The petitioners alleged that, in developing its energy conservation standards for distribution transformers, DOE did not comply with certain applicable provisions of EPCA and of the National Environmental Policy Act (NEPA), as amended (42 U.S.C. 4321 et seq.) DOE and the petitioners subsequently entered into a settlement agreement to resolve the petitions. The settlement agreement outlined an expedited timeline for the Department to determine whether to amend the energy conservation standards for liquid-immersed and medium-voltage dry-type distribution transformers. Under the original settlement agreement, DOE was required to publish by October 1, 2011, either a determination that the standards for these distribution transformers do not need to be amended or a NOPR that includes any new proposed standards and that meets all applicable requirements of EPCA and NEPA. Under an amended settlement agreement, the October 1, 2011, deadline for a DOE determination or proposed rule was extended to February 1, 2012. If DOE finds that amended standards are warranted, DOE must publish a final rule containing such amended standards by October 1, 2012.

On March 2, 2011, DOE published in the Federal Register a notice of public meeting and availability of its preliminary TSD for the Distribution Transformer Energy Conservation Standards Rulemaking, wherein DOE discussed and received comments on issues such as equipment classes of distribution transformers that DOE would analyze in consideration of amending the energy conservation standards for distribution transformers, the analytical framework, models and tools it is using to evaluate potential standards, the results of its preliminary analysis, and potential standard levels. 76 FR 11396. The notice is available on the above-referenced DOE website. To expedite the rulemaking process, DOE began at the preliminary analysis stage because it believes that many of the same methodologies and data sources that were used during the 2007 rulemaking rule remain valid. On April 5, 2011, DOE held a public meeting to discuss the preliminary TSD. Representatives of manufacturers, trade associations, electric utilities, energy conservation organizations, Federal regulators, and other interested parties attended this meeting. In addition, other interested parties submitted written comments about the TSD addressing a range of issues. These comments are discussed in the following sections of the NOPR.

On July 29, 2011, DOE published in the Federal Register a notice of intent to establish a subcommittee under the Energy Efficiency and Renewable Energy Advisory Committee (ERAC), in accordance with the Federal Advisory Committee Act and the Negotiated Rulemaking Act, to negotiate proposed Federal standards for the energy efficiency of medium-voltage dry-type and liquid immersed distribution transformers. 76 FR 45471. Stakeholders strongly supported a consensual rulemaking effort. DOE believed that, in this case, a negotiated rulemaking would result in a better informed NOPR and would minimize any potential negative impact of the NOPR. On August 12, 2011, DOE published in the Federal Register a similar notice of intent to negotiate proposed Federal standards for the energy efficiency of low-voltage dry-type distribution transformers. 76 FR 50148. The purpose of the subcommittee was to discuss and, if possible, reach consensus on a proposed rule for the energy efficiency of distribution transformers.

The ERAC subcommittee for medium-voltage liquid-immersed and dry-type distribution transformers consisted of representatives of parties having a defined stake in the outcome of the proposed standards, listed below.

- ABB Inc.
- AK Steel Corporation
- American Council for an Energy-Efficient Economy
- American Public Power Association
- Appliance Standards Awareness Project
- ATI-Allegheny Ludlum
- Baltimore Gas and Electric
- Cooper Power Systems
- Earthjustice
- Edison Electric Institute
- Fayetteville Public Works Commission
- Federal Pacific Company
- Howard Industries Inc.
- LakeView Metals
- Efficiency and Renewables Advisory Committee member
- Metglas, Inc.
- National Electrical Manufacturers Association

- National Resources Defense Council
- National Rural Electric Cooperative Association
- Northwest Power and Conservation Council
- Pacific Gas and Electric Company
- Progress Energy
- Prolec GE
- U.S. Department of Energy

The ERAC subcommittee for medium-voltage liquid-immersed and dry-type distribution transformers held meetings on September 15 through 16, 2011, October 12 through 13, 2011, November 8 through 9, 2011, and November 30 through December 1, 2011; the ERAC subcommittee also held public webinars on November 17 and December 14. During the course of the September 15, 2011, meeting, the subcommittee agreed to its rules of procedure., ratified its schedule of the remaining meetings, and defined the procedural meaning of consensus. The subcommittee defined consensus as unanimous agreement from all present subcommittee members. Subcommittee members were allowed to abstain from voting for an efficiency level; their votes counted neither toward nor against the consensus.

DOE presented its draft engineering, life-cycle cost and national impacts analysis and results. During the meetings of October 12 through 13, 2011, DOE presented its revised analysis and heard from subcommittee members on a number of topics. During the meetings on November 8 through 9, 2011, DOE presented its revised analysis, including life-cycle cost sensitivities based on exclusion ZDMH and amorphous steel as core materials. During the meetings on November 30 through December 1, 2011, DOE presented its revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their efficiency level recommendations. For medium-voltage liquid-immersed distribution transformers, the advocates, represented by the Appliance Standards Awareness Project (ASAP), recommended efficiency level (also referred to as “EL”) 3 for all design lines (also referred to as “DLs”). The National Electrical Manufacturers Association (NEMA) and AK Steel recommended EL 1 for all DLs except for DL 2, for which no change from the current standard was recommended. Edison Electric Institute (EEI) and ATI Allegheny Ludlum recommended EL1 for DLs 1, 3, and 4 and no change from the current standard or a proposed standard of less than EL 1 for DLs 2 and 5. Therefore, the subcommittee did not arrive at consensus regarding proposed standard levels for medium-voltage liquid-immersed distribution transformers.

For medium-voltage dry-type distribution transformers, the subcommittee arrived at consensus and recommended a proposed standard of EL2 for DLs 11 and 12, from which the proposed standards for DLs 9, 10, 13A, 13B would be scaled. Transcripts of the subcommittee meetings and all data and materials presented at the subcommittee meetings are available at the DOE website at: http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html.

The ERAC subcommittee held meetings on September 28, 2011, October 13-14, 2011, November 9, 2011, and December 1-2, 2011, for low-voltage distribution transformers. The ERAC subcommittee also held webinars on November 21, 2011, and December 20, 2011. During the course of the September 28, 2011, meeting, the subcommittee agreed to its rules of procedure, finalized the schedule of the remaining meetings, and defined the procedural meaning of consensus. The subcommittee defined consensus as unanimous agreement from all present subcommittee members. Subcommittee members were allowed to abstain from voting for an efficiency level; their votes counted neither toward nor against the consensus.

The ERAC subcommittee for low-voltage distribution transformers consisted of representatives of parties having a defined stake in the outcome of the proposed standards.

- AK Steel Corporation
- American Council for an Energy-Efficient Economy
- Appliance Standards Awareness Project
- ATI-Allegheny Ludlum
- EarthJustice
- Eaton Corporation
- Federal Pacific Company
- Lakeview Metals
- Efficiency and Renewables Advisory Committee member
- Metglas, Inc.
- National Electrical Manufacturers Association
- Natural Resources Defense Council
- ONYX Power
- Pacific Gas and Electric Company
- Schneider Electric
- U.S. Department of Energy

DOE presented its draft engineering, life-cycle cost and national impacts analysis and results. During the meetings of October 14, 2011, DOE presented its revised analysis and heard from subcommittee members on various topics. During the meetings of November 9, 2011, DOE presented its revised analysis. During the meetings of December 1, 2011, DOE presented its revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their energy efficiency level recommendations. For low-voltage dry-type distribution transformers, the advocates, represented by ASAP, recommended EL4 for all DLs, NEMA recommended EL 2 for DLs 7 and 8, and no change from the current standard for DL 6. EEI, AK Steel and ATI Allegheny Ludlum recommended EL 1 for DLs 7 and 8, and no change from the current standard for DL 6. The subcommittee did not arrive at consensus regarding a proposed standard for low-voltage dry-type distribution transformers. Transcripts of the subcommittee meetings and all data and materials presented at the subcommittee meetings are available at the DOE website at: http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html.

2.3 EQUIPMENT MARKET AND TECHNOLOGY ASSESSMENT

When initiating a standards rulemaking, DOE develops 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 market. Industry publications and trade journals, government agencies, trade organizations, and equipment literature provided the bulk of the information, including: (1) manufacturers and their approximate market shares, (2) equipment characteristics, and (3) industry trends. The appropriate sections of the NOPR describe the analysis and resulting information leading up to the proposed trial standard levels, while supporting documentation is provided in the TSD.

DOE categorizes covered equipment into separate equipment classes and formulates a separate energy conservation standard for each equipment class. The criteria for separation into different classes are type of energy used, capacity, and other performance-related features such as those that provide utility to the consumer or others deemed appropriate by the Secretary that would justify the establishment of a separate energy conservation standard. (42 U.S.C. 6295(q) and 6316(a))

Distribution transformers

As part of the market and technology assessment, DOE developed a list of technologies for consideration for improving the efficiency of distribution transformers. DOE typically uses information about existing and past technology options and prototype designs to determine which technologies manufacturers use to attain higher performance levels. In consultation with interested parties, 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 distribution transformers from trade publications, technical papers, research conducted in support of previous rulemakings concerning these equipment, and through consultation with manufacturers of components and systems. Since many options for improving equipment efficiency are available in existing equipment, equipment literature and direct examination provided additional information. Chapter 3 of the TSD includes the detailed list of all technology options identified.

2.4 SCREENING ANALYSIS

After DOE identified the technologies that could potentially improve the energy efficiency of distribution transformers, DOE conducted the screening analysis. The purpose of the screening analysis is to evaluate these technologies to determine which options to consider further and which options to screen out.

The screening analysis examines whether various technologies (1) are technologically feasible; (2) are practicable to manufacture, install, and service; (3) have an adverse impact on equipment utility or availability; and (4) have adverse impacts on health and safety. In consultation with interested parties, DOE reviews the list to determine if the technologies described in chapter 3 of the TSD are practicable to manufacture, install, and service; would adversely affect equipment utility or availability; or would have adverse impacts on health and safety. In the engineering analysis, DOE further considers the efficiency enhancement options (i.e., technologies) that it did not screen out in the screening analysis. Chapter 4 of the TSD contains further detail on the criteria that DOE uses.

2.5 ENGINEERING ANALYSIS

The engineering analysis establishes the relationship between the manufacturing production cost and the efficiency of distribution transformers. This relationship serves as the basis for cost/benefit calculations in terms of individual consumers, manufacturers, and the Nation. Chapter 5 discusses equipment classes DOE analyzed, the representative baseline units, the efficiency levels analyzed, the methodology DOE used to develop the manufacturing production costs, and the cost-efficiency curves.

In the engineering analysis, DOE evaluates a range of equipment efficiency levels and their associated manufacturing costs. The purpose of the analysis is to estimate the incremental manufacturer selling prices (MSPs) for equipment that would result from increasing efficiency levels above the level of the baseline model in each equipment class. The engineering analysis considers technologies not eliminated in the screening analysis. The LCC analysis and NIA use the cost-efficiency relationships developed in the engineering analysis.

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 teardowns of the equipment being analyzed.

For the NOPR analysis, DOE primarily used the design-option approach to develop its relationships for cost and efficiency for distribution transformers. DOE developed a manufacturing cost model for distribution transformers based on reverse engineering of purchased equipment. DOE estimated costs for these efficiency improvements based on the manufacturing cost model, information from component vendors, and information obtained through discussions with manufacturers. Chapter 5 of the TSD describes the methodology that DOE used to perform the efficiency level analysis and derive the cost-efficiency relationship.

2.6 MARKUPS TO DETERMINE EQUIPMENT PRICE

DOE uses markups to convert the manufacturer selling prices estimated in the engineering analysis to consumer prices, which then were used in the LCC, PBP, national impact, and manufacturer impact analyses. DOE calculates a separate markup for the baseline component of equipment's cost (baseline markup) and for the incremental increase in cost due to standards (incremental markup).

To develop markups, DOE identifies how the equipment is distributed from the manufacturer to the customer. After establishing appropriate distribution channels, DOE used data from the financial filings of manufacturers and distributors and other sources to determine how prices are marked up as the equipment passes from the manufacturer to the end consumer. See chapter 6 of the TSD for details on the development of markups.

2.7 ENERGY USE ANALYSIS

The energy use analysis, which assesses the energy savings potential from higher efficiency levels, provides the basis for the energy savings values used in the LCC and subsequent analyses. The goal of the energy use analysis is to generate a range of energy use values that reflects actual equipment use in American homes. The analysis uses information on use of actual equipment in the field to estimate the energy that would be used by new equipment at various efficiency levels. Chapter 7 of the TSD provides more detail about DOE's approach for characterizing energy use of distribution transformers.

2.8 LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

New or amended energy conservation standards affect equipment's operating expenses—usually decreasing them—and consumer prices for the equipment—usually increasing them. DOE analyzed the net effect of standards on consumers by evaluating the net change in LCC. To evaluate the net change in LCC, DOE used the cost-efficiency relationship derived in the engineering analysis along with the energy costs derived from the energy use analysis. Inputs to the LCC calculation include the installed cost of equipment to the consumer (consumer purchase price plus installation cost), operating expenses (energy expenses and maintenance costs), the lifetime of the unit, and a discount rate. These inputs are described in detail in chapter 8 of the TSD.

Because the installed cost of equipment typically increases while operating cost typically decreases in response to new standards, there is a time in the life of equipment having higher-than-baseline efficiency when the operating-cost benefit (in dollars) since the time of purchase is equal to the incremental first cost of purchasing the higher-efficiency equipment. The length of time required for equipment to reach this cost-equivalence point is known as the payback period (PBP).

Recognizing that several inputs used to determine consumer LCC and PBP are either variable or uncertain, DOE conducted the LCC and PBP analyses by modeling both the uncertainty and variability in the inputs using Monte Carlo simulation and probability distributions. DOE developed an LCC and PBP spreadsheet model that incorporates both Monte Carlo simulation and probability distributions by using Microsoft Excel spreadsheets combined with Crystal Ball, a commercially available add-in program.

For distribution transformers, it was necessary to determine the input values for a wide arrange of electricity costs that are seen by distribution transformer owners. DOE performed two electricity price analyses to determine the appropriate marginal prices for (1) liquid-immersed distribution transformers owned primarily by utility companies and (2) dry-type distribution transformers owned primarily by C&I building owners. For utility companies, the appropriate marginal price is the hourly system lambda or market-clearing price. For building owners, the electricity prices are derived from a tariff-based analysis. The two approaches are described in more detail below.

For liquid-immersed transformers, DOE based its energy price analysis on hourly system load and system lambda data collected from FERC (for regions without wholesale markets) or on hourly system load and day-ahead market clearing price data. In both cases, these prices represent the operating cost to the utility of meeting the next increment of load at any given time.

In any given hour, a utility's marginal price can be higher or lower than its average price; in general the hourly price can be represented as a function of the system load level.

In addition to the hourly energy cost, there is a capacity cost saving associated with improved transformer efficiency. If the efficiency of a utility's transformers is increased, then the utility will require less generation and transmission capacity to serve its customers' load. The size of the capacity savings is dependent on the total reduction in load over all the transformers owned by the utility during the hour of system peak. The reduction in system-coincident transformer peak load is determined by the joint probability distribution function between system and transformer loads. The cost of capacity is estimated using the 2010 annual auction clearing prices for regions with functioning capacity markets and using capacity cost factors from the AEO 2011 for the other regions.

For C&I building owners of dry-type transformers, DOE used marginal prices derived from a detailed analysis of utility tariffs (Coughlin et al., 2006). The tariff data and calculation tools were first developed by DOE for use in the Commercial Unitary Air Conditioning rulemaking. (U.S. Department of Energy, July, 2004).

For each of the CBECS 1992 and 1995 records used in the building sample, DOE used the monthly energy consumption and demand data, along with tariff data, to calculate a baseline electricity bill. To obtain marginal prices, two additional calculations were done. Because the electricity bill depends on both energy consumption and demand, separate marginal prices are needed to represent the effect of varying these two quantities independently. The monthly marginal energy consumption (or demand) price is calculated simply by decrementing the energy consumption (or demand) and recalculating the bill. The tariff data were collected in 2004. To update prices to the analysis year (2010), two other datasets were used: the report Average Regulated Retail Price of Electricity (Regulatory Research Associates, 2008) was used to estimate price increases between 2004 and 2007; and the Typical Bill and Average Price Reports (Edison Electric Institute, 2007–2010) was used to estimate price increases from 2007 to 2010.

The LCC and PBP analyses are described in more detail in chapter 8 of the TSD.

2.9 SHIPMENTS ANALYSIS

Forecasts of equipment shipments are needed to calculate the potential effects of standards on national energy use, NPV, and future manufacturer cash flows. DOE generated both shipments and efficiency forecasts for each equipment class. The shipments forecast calculates the total number of distribution transformers shipped each year over a 30 year period, beginning in 2016 and ending in 2045. To create this forecast, DOE combined current year shipments, discussed in the market assessment (chapter 3), with a compound annual growth rate for distribution transformers and generated unit shipment values through the analysis period. The efficiency forecast shows the distribution of shipments of distribution transformers by trial standard level (TSL), which determines the percentage of shipments affected by a standard. To develop its efficiency forecast, DOE first assessed present-day (2010) efficiency and then considered how the efficiency of new units might change by the first year of the analysis period (2016) and throughout the analysis period in the absence of new or amended Federal standards.

Chapter 9 of the TSD provides additional details on the shipments analysis.

2.10 NATIONAL IMPACT ANALYSIS

The national impact analysis estimates energy savings and assesses the NPV of consumer LCC savings at the national scale. The results can be used to identify the TSL that, for a given equipment class, yields the greatest energy savings while remaining cost effective from a consumer perspective. DOE estimated both NES and NPV for all candidate standard levels for each distribution transformers equipment class. To make the analysis more accessible and transparent to all interested parties, it is documented in a Microsoft Excel spreadsheet model that can be downloaded from the EERE website.

The NIA considers total installed cost (which includes manufacturer selling prices, distribution chain markups, sales taxes, and installation costs), operating expenses (energy, repair, and maintenance costs), equipment lifetime, and discount rate. However, where the LCC considers the savings and costs associated with standards for a set of representative units, the NIA considers the savings and costs associated with all units affected by standards during the entire analysis period. Chapter 10 provides additional details regarding the NIA.

2.10.1 National Energy Savings Analysis

The major inputs for determining the NES for equipment analyzed are annual unit energy consumption, shipments, lifetimes, and site-to-source conversion factors. DOE calculated national energy consumption for each year by multiplying unit energy consumption by the number of units in the installed base in that year. NES for a given year, then, is the difference in national energy consumption between the base case (without new efficiency standards) and each standards case. DOE estimated energy consumption and savings first in terms of site energy and then converted the savings into source energy. Cumulative energy savings are the sum of the NES estimates for each year.

2.10.2 Net Present Value Analysis

The inputs for determining net present value (NPV) of consumer benefits are: (1) total annual installed cost; (2) total annual savings in operating costs; (3) a discount factor; (4) present value of costs; and (5) present value of savings. DOE calculated net savings each year as the difference between the base case and each standards case in total savings in operating costs and total increases in installed costs. DOE calculated savings over the life of equipment, accounting for differences in yearly electricity rates. 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% to discount future costs and savings to present values.

DOE calculated increases in total installed costs as the difference in total installed cost between the base 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 base case, cost increases appear as negative values in the NPV.

DOE expressed savings in operating costs as decreases associated with the lower energy consumption of equipment bought in the standards case compared to the base 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.

2.11 CONSUMER SUBGROUP ANALYSIS

The consumer subgroup analysis evaluates economic impacts on selected groups of consumers who might be adversely affected by a change in the national energy conservation standards for the considered equipment. DOE performed LCC subgroup analyses for utilities that have underground distribution systems and that use vault-installed transformers.. DOE evaluated the potential LCC impacts and PBPs for these consumers using the LCC spreadsheet model. Chapter 11 of the TSD provides more detail.

2.12 MANUFACTURER IMPACT ANALYSIS

DOE performed a manufacturer impact analysis (MIA) to estimate the financial impact of energy conservation standards on manufacturers of distribution transformers, and to calculate the impact of such standards on employment and manufacturing capacity. The MIA has both quantitative and qualitative aspects. The quantitative part of the MIA relies on the government regulatory impact model (GRIM), an industry-cash-flow model customized for this rulemaking. The GRIM inputs are information regarding the industry cost structure, shipments, and revenues. This includes information from many of the analyses described above, such as manufacturing costs and prices from the engineering analysis and shipments forecasts. The key GRIM output is the industry net present value (INPV). Different sets of assumptions (scenarios) will produce different results. The qualitative part of the MIA addresses factors such as equipment characteristics, characteristics of particular firms, and market and equipment trends, and includes assessment of the impacts of standards on subgroups of manufacturers. The complete MIA is described in chapter 12 of the TSD.

DOE conducted each MIA in this rulemaking in three phases. In Phase I, DOE created an industry profile to characterize the industry and identify important issues that require consideration. In Phase II, DOE prepared an industry cash-flow model and an interview questionnaire to guide subsequent discussions. In Phase III, DOE interviewed manufacturers and assessed the impacts of standards both quantitatively and qualitatively. DOE assessed industry and subgroup cash flow and NPV using the GRIM. DOE then assessed impacts on competition, manufacturing capacity, employment, and regulatory burden based on manufacturer interview feedback and discussions.

2.13 EMPLOYMENT IMPACT ANALYSIS

The imposition of standards can affect employment both directly and indirectly. Direct employment impacts are changes, produced by new standards, in the number of employees at plants that produce the covered equipment. DOE evaluated direct employment impacts in the manufacturer impact analysis. Indirect employment impacts that occur because of the imposition of standards may result from consumers shifting expenditures between goods (the substitution effect) and from changes in income and overall expenditure levels (the income effect). DOE utilizes Pacific Northwest National Laboratory's ImSET model to investigate the combined direct and indirect employment impacts. The ImSET model, which was developed for DOE's Office of Planning, Budget, and Analysis, estimates the employment and income effects energy-saving technologies produced in buildings, industry, and transportation. In comparison with simple economic multiplier approaches, ImSET allows for more complete and automated analysis of the economic impacts of energy conservation investments. Further detail is provided in chapter 13 of the TSD.

2.14 UTILITY IMPACT ANALYSIS

The utility impact analysis includes an analysis of selected effects of new energy conservation standards on the electric and the gas utility industries. For this analysis, DOE adapted National Energy Modeling System (NEMS), a large multi-sectoral, partial-equilibrium model of the U.S. energy sector that the EIA developed throughout the past decade primarily for preparing EIA's AEO. In previous rulemakings, a variant of NEMS (currently termed NEMS-BT, BT referring to DOE's Building Technologies Program) was developed to address the specific impacts of an energy conservation standard.

Available in the public domain, NEMS produces a widely recognized baseline energy forecast for the United States through 2030. The typical NEMS outputs include forecasts of electricity sales, prices, and electric generating capacity. DOE conducts the utility impact analysis as a scenario that departs from the latest AEO reference case. In other words, the energy savings impacts from energy conservation standards are modeled using NEMS-BT to generate forecasts that deviate from the AEO reference case.

As part of the utility impact analysis, DOE analyzed the potential impact on electricity prices resulting from standards on distribution transformers and the associated benefits for all electricity users in all sectors of the economy. Further detail is provided in chapter 14 of the TSD.

2.15 EMISSIONS ANALYSIS

In the emissions analysis, DOE estimated the reduction in power sector emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), and mercury (Hg) using the NEMS-BT computer model. In the emissions analysis, NEMS-BT is run similarly to the AEO NEMS, except that distribution transformers energy use is reduced by the amount of energy saved (by fuel type) due to each considered standard level. The inputs of national energy savings come from the NIA spreadsheet model, while the output is the forecasted physical emissions. The net benefit of each considered standard level is the difference between the forecasted emissions estimated by NEMS-BT at that level and the AEO 2011 Reference Case.

2.15.1 Carbon Dioxide

In the absence of any Federal emissions control regulation of power plant emissions of CO_2, a DOE standard is likely to result in reductions of these emissions. The CO_2 emission reductions likely to result from a standard will be estimated using NEMS-BT and national energy savings estimates drawn from the NIA spreadsheet model. The net benefit of the standard is the difference between emissions estimated by NEMS-BT at each standard level considered and the *AEO* Reference Case. NEMS-BT tracks CO_2 emissions using a detailed module that provides results with broad coverage of all sectors and inclusion of interactive effects.

2.15.2 Sulfur Dioxide

SO_2 emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap and trading programs, and DOE has preliminarily determined that these programs create uncertainty about the potential standards' impact on SO_2 emissions. 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, 70 Fed. Reg. 25162 (May 12, 2005)), which created an allowance-based trading program. Although CAIR has been remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), see *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008), it remains in effect temporarily, consistent with the D.C. Circuit's earlier opinion in *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). On July 6, 2010, EPA issued the Transport Rule proposal, a replacement for CAIR.75 FR 45210 (Aug. 2, 2010). EPA issued the final transport rule, entitled the Cross-State Air Pollution Rule, on July 6, 2011. 76 FR 48208 (August 8, 2011). Because the AEO 2011 NEMS-BT that DOE is using for this rulemaking assumes the implementation of CAIR, DOE has not been able to take into account the effects of the Transport Rule for this rulemaking. [d]

The attainment of emissions caps is typically flexible among EGUs and is enforced through the use of emissions allowances and tradable permits. Under existing EPA regulations,

[d] DOE notes that future iterations of the NEMS-BT model will incorporate any changes necessitated by issuance of the Cross-State Air Pollution Rule.

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. However, if the standard resulted in a permanent increase in the quantity of unused emissions allowances, there would be an overall reduction in SO_2 emissions from the standards. While there remains some uncertainty about the ultimate effects of efficiency standards on SO_2 emissions covered by the existing cap and trade system, the NEMS-BT modeling system that DOE uses to forecast emissions reductions currently indicates that no physical reductions in power sector emissions would occur for SO_2.

2.15.3 Nitrogen Oxides

Under CAIR, there is a cap on NO_X emissions in 28 eastern states and the District of Columbia. All these States and D.C. have elected to reduce their NO_X emissions by participating in cap-and-trade programs for EGUs. Therefore, energy conservation standards for distribution transformers may have little or no physical effect on these emissions in the 28 eastern states and the D.C. for the same reasons that they may have little or no physical effect on NO_X emissions. DOE is using the NEMS-BT to estimate NO_X emissions reductions from possible standards in the States where emissions are not capped.

2.15.4 Mercury

In the absence of caps, a DOE energy conservation standard could reduce Hg emissions and DOE used NEMS-BT to estimate these emission reductions. Although at present there are no national, Federally binding regulations for mercury from EGUs, on March 16, 2011, EPA proposed national emissions standards for hazardous air pollutants (NESHAPs) for mercury and certain other pollutants emitted from coal and oil-fired EGUs. 76 FR 24976. The NESHAPs do not include a trading program and, as such, DOE's energy conservation standards would likely reduce Hg emissions. For the emissions analysis for this rulemaking, DOE estimated mercury emissions reductions using NEMS-BT based on *AEO2010*, which does not incorporate the NESHAPs. DOE expects that future versions of the NEMS-BT model will reflect the implementation of the NESHAPs.

2.15.5 Particulate Matter

DOE acknowledges that particulate matter (PM) exposure can impact human health. Power plant emissions can have either direct or indirect impacts on PM. A portion of the pollutants emitted by a power plant are in the form of particulates as they leave the smoke stack. These are direct, or primary, PM emissions. However, the great majority of PM emissions associated with power plants are in the form of secondary sulfates, which are produced at a significant distance from power plants by complex atmospheric chemical reactions that often involve the gaseous (non-particulate) emissions of power plants, mainly SO_2 and NO_X. The quantity of the secondary sulfates produced is determined by a very complex set of factors including the atmospheric quantities of SO_2 and NO_X, and other atmospheric constituents and conditions. Because these highly complex chemical reactions produce PM comprised of different constituents from different sources, EPA does not distinguish direct PM emissions from power plants from the secondary sulfate particulates in its ambient air quality requirements, PM monitoring of ambient air quality, or PM emissions inventories. For these reasons, it is not currently possible to determine how the standards would impact either direct or indirect PM emissions. Therefore, DOE is not planning to assess the impact of these standards on PM emissions. Further, as described previously, it is uncertain whether efficiency standards will result in a net decrease in power plant emissions of SO_2, which are now largely regulated by cap and trade systems.

2.16 MONETIZATION OF EMISSIONS REDUCTIONS

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

In order to estimate the monetary value of benefits resulting from reduced emissions of CO_2 emissions, DOE used in its analysis the most current Social Cost of Carbon (SCC) values developed and/or agreed to by interagency reviews. 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 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.

At the time of this notice, the most recent interagency estimates of the potential global benefits resulting from reduced CO_2 emissions in 2010 were $4.7, $21.4, $35.1, and $64.9 per metric ton in 2007 dollars. These values are then adjusted to 2010$ using the appropriate standard GDP deflator values. 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. See appendix 16A of this TSD for the full range of annual SCC estimates from 2010 to 2050. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the discount rates that had been used to obtain the SCC values in each case.

DOE recognizes that scientific and economic knowledge continues to evolve rapidly 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 estimates the potential monetary benefit of reduced NO_X emissions resulting from the standard levels it considers. For NO_X emissions, available estimates suggest a very wide range of monetary values for NO_X emissions, ranging from \$370 per ton to \$3,800 per ton of NO_X from stationary sources, measured in 2001\$ (equivalent to a range of \$450 to \$4,623 per ton in 2010\$).[e] In accordance with U.S. Office of Management and Budget (OMB) guidance, DOE will conduct two calculations of the monetary benefits derived using each of the economic values used for NO_x, one using a real discount rate of 3 percent and another using a real discount rate of 7 percent.[f]

DOE did not monetize estimates of Hg reduction in this rulemaking. DOE is aware of multiple agency efforts to determine the appropriate range of values used in evaluating the potential economic benefits of reduced Hg emissions. DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it once again monetizes Hg in its rulemakings. Further detail is provided in chapter16 of the TSD.

2.17 REGULATORY IMPACT ANALYSIS

In the NOPR stage, DOE prepared a regulatory impact analysis (RIA) pursuant to Executive Order 12866, Regulatory Planning and Review, 58 FR 51735, October 4, 1993, which is subject to review by the Office of Information and Regulatory Affairs at the Office of Management and Budget. The RIA addresses the potential for non-regulatory approaches to supplant or augment energy conservation standards in order to improve the energy efficiency or reduce the energy consumption of the equipment covered under this rulemaking.

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

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[e] For additional information, refer to U.S. Office of Management and Budget, Office of Information and Regulatory Affairs, 2006 Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities, Washington, DC.

[f] OMB, Circular A-4: Regulatory Analysis (Sept. 17, 2003).

CHAPTER 3. MARKET AND TECHNOLOGY ASSESSMENT

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CHAPTER 3. MARKET AND TECHNOLOGY ASSESSMENT

3.1 INTRODUCTION

This chapter provides a profile of the distribution transformer industry in the United States. The U.S. Department of Energy (DOE) developed the market and technology assessment presented in this chapter primarily from publicly available information. This assessment is helpful in identifying the major manufacturers and their equipment characteristics, which form the basis for the engineering and life-cycle cost (LCC) analyses.

3.2 DISTRIBUTION TRANSFORMER DEFINITIONS

The definition of a distribution transformer was established in the Energy Policy Act (EPACT) of 2005, and further refined by DOE when it was codified into the Code of Federal Regulations (CFR) on April 27, 2006. 10 CFR 431.192; 71 FR 24972.

EPACT 2005 established that the definition of a distribution transformer would be as follows:

"The term 'distribution transformer' means a transformer that -

(i) has an input voltage of 34.5 kilovolts or less;
(ii) has an output voltage of 600 volts or less; and
(iii) is rated for operation at a frequency of 60 Hertz.

The term 'distribution transformer' does not include –

(i) a transformer with multiple voltage taps, the highest of which equals at least 20 percent more than the lowest;
(ii) a transformer that is designed to be used in a special purpose application and is unlikely to be used in general purpose applications, such as a drive transformer, rectifier transformer, auto-transformer, impedance transformer, regulating transformer, sealed and non-ventilating transformer, machine tool transformer, welding transformer, grounding transformer, or testing transformer; or
(iii) any transformer not listed in clause (ii) that is excluded by the Secretary by rule because
  (I) the transformer is designed for a special application;
  (II) the transformer is unlikely to be used in general purpose applications; and
  (III) the application of standards to the transformer would not result in significant energy savings.

The term 'low-voltage dry-type distribution transformer' means a distribution transformer that -

(A) has an input voltage of 600 volts or less;

(B) is air-cooled; and
(C) does not use oil as a coolant."

The term 'transformer' means a device consisting of two or more coils of insulated wire that transfers alternating current by electromagnetic induction from one coil to another to change the original voltage or current value.

In the April 2006 final rule, DOE clarified some of the exemptions which were not defined in the statute, based on the test procedure rulemaking which had been developing the definition of a distribution transformer. These definitions were based primarily on industry sources including the Institute of Electrical and Electronics Engineers (IEEE) and the National Electrical Manufacturers Association (NEMA). In addition, EPACT 2005 did not provide kVA ranges which were used by DOE in this rulemaking proceeding to bound its scope of coverage. Therefore, in the April 2006 final rule, DOE established kilovolt-ampere (kVA) ranges that were consistent with the scope of applicability for the test procedure and energy conservation standards rulemakings DOE had been conducting on distribution transformers. This means that DOE's coverage authority granted by Congress is broader than that subset of distribution transformers that are being regulated in this proceeding.

The following text includes all the definitions that were codified into 10 CFR 431.192 in the April 2006 final rule for distribution transformers. DOE requests comment on a number of changes in the February 2012 notice, but proposes only that the definitions of "rectifier transformer" and "testing transformer" stipulate that such units indicate on their nameplates that they are for such purposes exclusively.

Autotransformer means a transformer that:
(a) Has one physical winding that consists of a series winding part and a common winding part;
(b) Has no isolation between its primary and secondary circuits; and
(c) During step-down operation, has a primary voltage that is equal to the total of the series and common winding voltages, and a secondary voltage that is equal to the common winding voltage.

Basic model means a group of models of distribution transformers manufactured by a single manufacturer, that have the same insulation type (i.e., liquid-immersed or dry-type), have the same number of phases (i.e., single or three), have the same standard kVA rating, and do not have any differentiating electrical, physical or functional features that affect energy consumption. Differences in voltage and differences in basic impulse insulation level (BIL) rating are examples of differentiating electrical features that affect energy consumption.

Distribution transformer means a transformer that -
(1) Has an input voltage of 34.5 kV or less;
(2) Has an output voltage of 600 V or less;
(3) Is rated for operation at a frequency of 60 Hz; and
(4) Has a capacity of 10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units; but

(5) The term “distribution transformer” does not include a transformer that is an–
- (i) Autotransformer;
- (ii) Drive (isolation) transformer;
- (iii) Grounding transformer;
- (iv) Machine-tool (control) transformer;
- (v) Nonventilated transformer;
- (vi) Rectifier transformer;
- (vii) Regulating transformer;
- (viii) Sealed transformer;
- (ix) Special-impedance transformer;
- (x) Testing transformer;
- (xi) Transformer with tap range of 20 percent or more;
- (xii) Uninterruptible power supply transformer; or
- (xiii) Welding transformer.

Drive (isolation) transformer means a transformer that -
- (a) Isolates an electric motor from the line;
- (b) Accommodates the added loads of drive-created harmonics; and
- (c) Is designed to withstand the additional mechanical stresses resulting from an alternating current adjustable frequency motor drive or a direct current motor drive.

Efficiency means the ratio of the useful power output to the total power input.

Excitation current or no-load current means the current that flows in any winding used to excite the transformer when all other windings are open-circuited.

Grounding transformer means a three-phase transformer intended primarily to provide a neutral point for system-grounding purposes, either by means of:
- (a) A grounded wye primary winding and a delta secondary winding; or
- (b) A transformer with its primary winding in a zig-zag winding arrangement, and with no secondary winding.

Liquid-immersed distribution transformer means a distribution transformer in which the core and coil assembly is immersed in an insulating liquid.

Load loss means, for a distribution transformer, those losses incident to a specified load carried by the transformer, including losses in the windings as well as stray losses in the conducting parts of the transformer.

Machine tool (control) transformer means a transformer that is equipped with a fuse or other over-current protection device, and is generally used for the operation of a solenoid, contactor, relay, portable tool, or localized lighting.

Medium-voltage dry-type distribution transformer means a distribution transformer in which the core and coil assembly is immersed in a gaseous or dry compound insulating medium, and which has a rated primary voltage between 601 V and 35 kV.

No-load loss means those losses that are incident to the excitation of the transformer.

Nonventilated transformer means a transformer constructed so as to prevent external air circulation through the coils of the transformer while operating at zero gauge pressure.

Phase angle means the angle between two phasors, where the two phasors represent progressions of periodic waves of either:

(1) Two voltages;
(2) Two currents; or
(3) A voltage and a current of an alternating current circuit.

Phase angle correction means the adjustment (correction) of measurement data to negate the effects of phase angle error.

Phase angle error means incorrect displacement of the phase angle, introduced by the components of the test equipment.

Rectifier transformer means a transformer that operates at the fundamental frequency of an alternating-current system and that is designed to have one or more output windings connected to a rectifier.

Reference temperature means 20˚ C for no-load loss, 55˚ C for load loss of liquid-immersed distribution transformers at 50 percent load, and 75˚ C for load loss of both low-voltage and medium-voltage dry-type distribution transformers, at 35 percent load and 50 percent load, respectively. It is the temperature at which the transformer losses must be determined, and to which such losses must be corrected if testing is done at a different point. (These temperatures are specified in the test method in Appendix A to this part.)

Regulating Transformer means a transformer that varies the voltage, the phase angle, or both voltage and phase angle, of an output circuit and compensates for fluctuation of load and input voltage, phase angle or both voltage and phase angle.

Sealed Transformer means a transformer designed to remain hermetically sealed under specified conditions of temperature and pressure.

Special-Impedance Transformer means any transformer built to operate at an impedance outside of the normal impedance range for that transformer’s kVA rating. The normal impedance range for each kVA rating for liquid-immersed and dry-type transformers is shown in Table 3.2.1 and Table 3.2.2, respectively.

Table 3.2.1 Normal Impedance Ranges for Liquid-Immersed Transformers

Single-Phase Transformers		Three-Phase Transformers	
kVA	**Impedance (%)**	**kVA**	**Impedance (%)**
10	1.0-4.5	15	1.0-4.5
15	1.0-4.5	30	1.0-4.5
25	1.0-4.5	45	1.0-4.5
37.5	1.0-4.5	75	1.0-5.0
50	1.5-4.5	112.5	1.2-6.0
75	1.5-4.5	150	1.2-6.0
100	1.5-4.5	225	1.2-6.0
167	1.5-4.5	300	1.2-6.0
250	1.5-6.0	500	1.5-7.0
333	1.5-6.0	750	5.0-7.5
500	1.5-7.0	1000	5.0-7.5
667	5.0-7.5	1500	5.0-7.5
833	5.0-7.5	2000	5.0-7.5
		2500	5.0-7.5

Table 3.2.2 Normal Impedance Ranges for Dry-Type Transformers

Single-Phase Transformers		Three-Phase Transformers	
kVA	**Impedance (%)**	**kVA**	**Impedance (%)**
15	1.5-6.0	15	1.5-6.0
25	1.5-6.0	30	1.5-6.0
37.5	1.5-6.0	45	1.5-6.0
50	1.5-6.0	75	1.5-6.0
75	2.0-7.0	112.5	1.5-6.0
100	2.0-7.0	150	1.5-6.0
167	2.5-8.0	225	3.0-7.0
250	3.5-8.0	300	3.0-7.0
333	3.5-8.0	500	4.5-8.0
500	3.5-8.0	750	5.0-8.0
667	5.0-8.0	1000	5.0-8.0
833	5.0-8.0	1500	5.0-8.0
		2000	5.0-8.0
		2500	5.0-8.0

Temperature Correction means the mathematical correction(s) of measurement data, obtained when a transformer is tested at a temperature that is different from the reference temperature, to the value(s) that would have been obtained if the transformer had been tested at the reference temperature.

Test Current means the current of the electrical power supplied to the transformer under test.

Test Frequency means the frequency of the electrical power supplied to the transformer under test.

Test Voltage means the voltage of the electrical power supplied to the transformer under test.

Testing Transformer means a transformer used in a circuit to produce a specific voltage or current for the purpose of testing electrical equipment.

Total Loss means the sum of the no-load loss and the load loss for a transformer.

Transformer with Tap Range of 20 percent or more means a transformer with multiple voltage taps, the highest of which equals at least 20 percent more than the lowest, computed based on the sum of the deviations of the voltages of these taps from the transformer's nominal voltage.

Uninterruptible Power Supply Transformer means a transformer that is used within an uninterruptible power system, which in turn supplies power to loads that are sensitive to power failure, power sags, over voltage, switching transients, line noise, and other power quality factors.

Waveform Correction means the adjustment(s) (mathematical correction(s)) of measurement data obtained with a test voltage that is non-sinusoidal, to a value(s) that would have been obtained with a sinusoidal voltage.

Welding Transformer means a transformer designed for use in arc welding equipment or resistance welding equipment.

3.3 PROPOSED DEFINITIONS

As explained in the February 2012 notice, the negotiating committee explored the possibility of establishing new equipment classes for vault, network, and data center transformers. The proposed definitions are listed below.

a) A “network transformer” is one–

   i) designed for use in a vault,

   ii) designed for occasional submerged operation in water,

   iii) designed to feed a system of variable capacity system of interconnected secondaries, and

   iv) built per the requirements of IEEE C57.12.40-(year)

b) A “vault-type” transformer is one–

   i) designed for use in a vault,

   ii) designed for occasional submerged operation in water, and

   iii) built per the requirements of IEEE C57.12.23-(year) or IEEE C57.12.24-(year), respectively.

c) Data center transformer means a three-phase low-voltage dry-type distribution transformer that—

   i) is designed for use in a data center distribution system and has a nameplate identifying the transformer as being for this use only;

   ii) has a maximum peak energization current (or in-rush current) less than or equal to four times its rated full load current multiplied by the square root of 2, as measured under the following conditions—

      (1) during energization of the transformer without external devices attached to the transformer that can reduce inrush current;

(2) the transformer shall be energized at zero +/- 3 degrees voltage crossing of A phase. Five consecutive energization tests shall be performed with peak inrush current magnitudes of all phases recorded in every test. The maximum peak inrush current recorded in any test shall be used;

(3) the previously energized and then de-energized transformer shall be energized from a source having available short circuit current not less than 20 times the rated full load current of the winding connected to the source; and

(4) the source voltage shall not be less than 5 percent of the rated voltage of the winding energized; and

iii) is manufactured with at least two of the following other attributes:

(1) listed by NRTL for a K-factor rating, as defined in UL standard 1561: 2011 Fourth Edition, greater than K-4;

(2) temperature rise less than 130°C with class 220 insulation or temperature rise less than 110°C with class 200 insulation;

(3) a secondary winding arrangement that is not delta or wye (star);

(4) copper primary and secondary windings;

(5) an electrostatic shield; or

(6) multiple outputs at the same voltage a minimum of 15° apart, which when summed together equal the transformer's input kVA capacity.

3.4 EQUIPMENT CLASSES

DOE divides covered equipment into classes by: (a) the type of energy used; (b) the capacity; or (c) any performance-related features that affect consumer utility or efficiency. (42 U.S.C. 6295(q)) Different energy efficiency standards may apply to different equipment classes. In the previous rulemaking on distribution transformers with a final rule published in October

2007, DOE proposed 10 equipment classes and received general support on these equipment classes. The 10 equipment classes divided up the population of distribution transformers by:

(a) Type of transformer insulation - liquid-immersed or dry-type,
(b) Number of phases - single or three,
(c) Voltage class - low or medium (for dry-type units only), and
(d) Basic impulse insulation level (for medium-voltage, dry-type units only).

Insulation type refers the the medium used to electrically insulate and thermally cool a transformer's windings. Although liquid insulations have advantages in both aspects, they pose an additional risk of leaking, catching fire, or catastrophic failure that dry-type units do not and, therefore, are almost exclusively limited to outdoor use. Though less efficient, dry-type units offer additional utility to the consumer.

Number of phases refers to the type of electrical power that the transformer can process. Most power is transmitted in three-phase form over longer distances and split into its constituent phases at some point along the distribution chain. Three-phase units cannot be used in single-phase applications and, therefore, offer different utility to the consumer.

Voltage class refers to whether or not a transformer's input voltage is above 600 ("medium") or 600 and less ("low"). A transformer's input voltage is dictated by the application requirements and so medium- and low-voltage transformers offer different utility to the consumer.

Finally, basic impulse insulation level refers to how resistant a transformer is to very large voltage transients (often arising from lightning strikes). It is related to both input voltage and likelihood of exposure to such transients. Because both of those criteria are dictated by the transformer's particular application, BIL can be said to offer additional utility to the consumer. DOE has previously used BIL to establish equipment classes only for medium-voltage, dry-type transformers because it affects energy efficiency much more strongly there than in liquid-immersed and low-voltage units. As standards rise, however, there may be the potential for BIL rating to materially affect efficiency in liquid-immersed units and DOE requests comment in the February 2012 notice on the matter.

On August 8, 2005, the President signed into law EPACT 2005, which contained a provision establishing energy conservation standards for two of DOE's equipment classes (ECs)—EC3, low-voltage, single-phase, dry-type and EC4, low-voltage, three-phase, dry-type. With standards thereby established for low-voltage, dry-type distribution transformers, DOE no longer considered these two equipment classes for standards during the previous rulemaking. Since the current rulemaking is considering new standards for liquid-immersed and medium, dry-type voltage distribution transformers, DOE has decided to also revisit low-voltage, dry-type distribution transformers to determine if higher efficiency standards are justified. Table 3.4.1 presents the ten equipment classes within the scope of this rulemaking analysis, and provides the kVA range associated with each.

Table 3.4.1 Distribution Transformer Equipment Classes

EC* #	Insulation	Voltage	Phase	BIL Rating	kVA Range
EC1	Liquid-Immersed	Medium	Single	-	10-833 kVA
EC2	Liquid-Immersed	Medium	Three	-	15-2500 kVA
EC3	Dry-Type	Low	Single	-	15-333 kVA
EC4	Dry-Type	Low	Three	-	15-1000 kVA
EC5	Dry-Type	Medium	Single	20-45kV BIL	15-833 kVA
EC6	Dry-Type	Medium	Three	20-45kV BIL	15-2500 kVA
EC7	Dry-Type	Medium	Single	46-95kV BIL	15-833 kVA
EC8	Dry-Type	Medium	Three	46-95kV BIL	15-2500 kVA
EC9	Dry-Type	Medium	Single	≥ 96kV BIL	75-833 kVA
EC10	Dry-Type	Medium	Three	≥ 96kV BIL	225-2500 kVA

* EC = Equipment Class

Basic impulse insulation level (BIL) refers to the level of insulation wound into a transformer, dictating its design voltage. Generally, higher BIL ratings have lower transformer operating efficiencies because the additional insulation and necessary clearances increase the distance between the core steel and the windings, contributing to higher losses. In addition, as the overall size of the windings increases due to additional insulation surrounding each wire, the core window through which the windings pass must increase, creating a larger core and increasing losses in the core. Recognizing this important aspect of transformer design, and after consultation with industry experts, DOE determined that differentiation of the energy efficiency standards by BIL level would be necessary for medium-voltage (MV), dry-type units, since these transformers experience significant variability in efficiency due to their BIL ratings. This decision is consistent with NEMA's TP 1-2002 (described in section 3.8.1).

3.5 NATIONAL SHIPMENT ESTIMATE

To prepare an estimate of the national impact of energy conservation standards for distribution transformers, DOE needed to estimate annual transformer shipments. For accuracy in this calculation, unit shipments were required by equipment class and kVA rating within each equipment class. Detailed shipment information like this is highly sensitive to manufacturers, many of whom indicated to DOE they would not be able to disclose their shipments. DOE researched public sources of transformer shipment information, such as the data compiled by the U.S. Census Bureau, but found that the data are aggregated, with many kVA ratings bundled in one value. Thus, DOE determined that it would not be possible to create an accurate estimate of transformers by kVA rating using U.S. Census Bureau data.

Instead, to develop its shipments estimate, DOE contracted a company with considerable knowledge of the U.S. transformer industry. This contractor has collectively more than 80 years of experience working in both the liquid-immersed and dry-type transformer industry in the U.S. DOE tasked the contractor with using its knowledge of the market, plus a limited number of consultative calls, to compile a national estimate of shipments for liquid-immersed and dry-type transformers.

Figure 3.5.1 through Figure 3.5.2 present the total aggregate shipment estimates for liquid-immersed units, while Figure 3.5.3 through Figure 3.5.4 present low-voltage and medium-voltage dry-type units. These pie charts show the estimated shipments for 2009 in both number of transformers and cumulative megavolt-ampere (MVA) of transformer capacity. The superclasses are subdivided into two principal groups—single-phase and three-phase. To simplify the illustrations, the single-phase and three-phase medium-voltage, dry-type units are shown each as aggregations of the three equipment classes presented in Table 3.4.1, where they are broken down by BIL rating. This was necessary as the separate market shares of medium-voltage, dry-type by BIL rating are small compared to the low-voltage, dry-type units. A detailed breakdown of the shipment estimates by equipment class and kVA rating appears in the shipments analysis (Chapter 9 of this TSD).

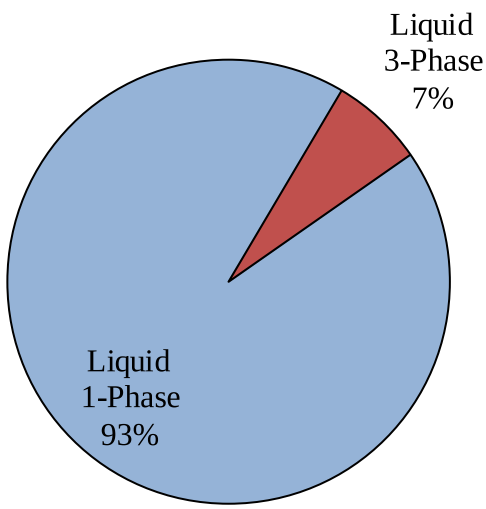

Figure 3.5.1 Liquid-Immersed Unit Shipments, 2009

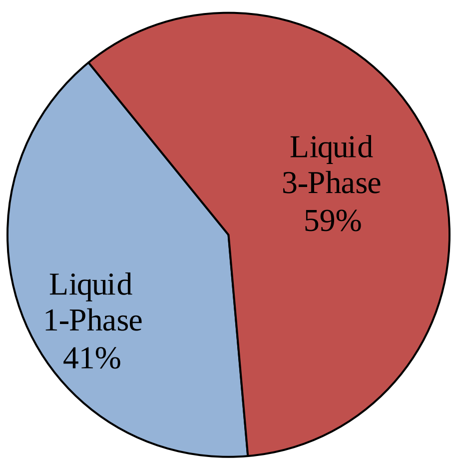

Figure 3.5.2 Liquid-Immersed Megavolt-Ampere Capacity Shipments, 2009

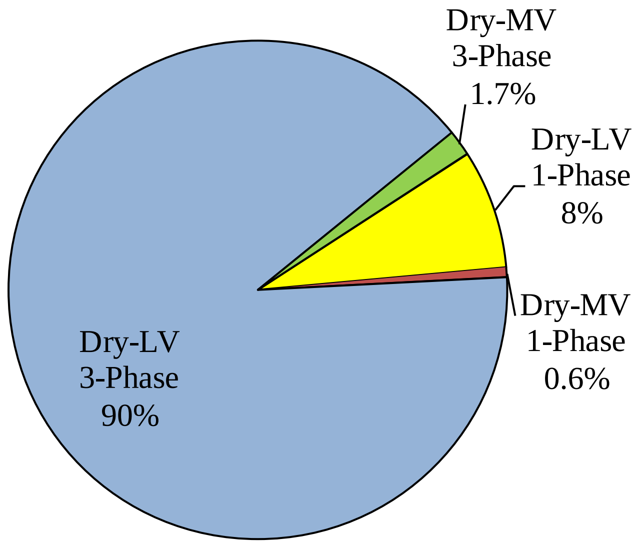

Figure 3.5.3 Dry-Type Unit Shipments, 2009

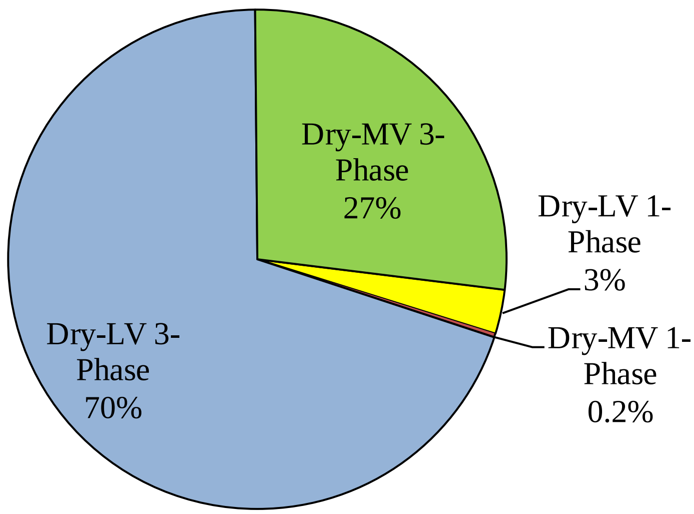

Figure 3.5.4 Dry-Type Megavolt-Ampere Capacity Shipments, 2009

Table 3.5.1 presents the actual shipment estimates by equipment class and the estimated value of these shipments, approximately $2.09 billion in 2009.

Table 3.5.1 National Distribution Transformer Shipment Estimates for 2009

Distribution Transformer Equipment Class	Units Shipped	MVA Capacity Shipped	Shipment Value (2009 US$million)
Liquid-immersed, medium-voltage, single-phase	683,726	21,994	714.8
Liquid-immersed, medium-voltage, three-phase	49,739	32,266	786.0
Dry-type, low-voltage, single-phase	17,740	647	22.0
Dry-type, low-voltage, three-phase	206,929	15,778	394.4
Dry-type, medium-voltage, single-phase, 20-45 kV BIL	709	23	0.7
Dry-type, medium-voltage, three-phase, 20-45 kV BIL	522	257	6.2
Dry-type, medium-voltage, single-phase, 46-95 kV BIL	546	23	0.8
Dry-type, medium-voltage, three-phase, 46-95 kV BIL	2,074	3,655	98.7
Dry-type, medium-voltage, single-phase, ≥ 96 kV BIL	202	9	0.3
Dry-type, medium-voltage, three-phase, ≥ 96 kV BIL	1,286	2,206	66.2
Total	963,473	76,858	2,090.1

The liquid-immersed transformer market accounted for 76 percent of the distribution transformers sold in the United States in 2009 (on a unit basis). These transformers accounted for 71 percent of the distribution transformer capacity measured in MVA, and 72 percent of the dollar value of the 2009 shipments. On a unit basis, more than 93 percent of the liquid-immersed shipments are single-phase. However, these single-phase units tend to have lower kVA ratings than the three-phase units, which are more than 59 percent of the total MVA capacity shipped of liquid-immersed distribution transformers in 2009.

In the dry-type market, low-voltage, three-phase distribution transformers dominate, accounting for 90 percent of units and 70 percent of MVA shipped. Medium-voltage, three-phase units accounted for only 1.7 percent of the units shipped, but were 27 percent of MVA shipments in 2009. The low-voltage, single-phase units were about 8 percent of the dry-type units shipped; however, because their kVA ratings tend to be small, they only accounted for about 3 percent of all dry-type MVA shipments in 2009. Medium-voltage, single-phase units occupy a small part of the market, representing 0.6 percent of the dry-type units shipped and 0.2 percent of dry-type MVA shipped.

In preparing its estimates of the distribution transformer market, DOE's contractor identified several key insights to place the 2009 shipment estimates into perspective.

1. Fundamentally, 2009 was characterized by slow housing starts, minimal industrial and commercial activity, and general retrenchment in the country.

2. Distribution transformer shipments reflected the slow economic activity in all segments.

3. The data for 2009 looked relatively weak compared to DOE's previous distribution transformer market size estimate from 2001.

    a. Liquid-immersed, single-phase distribution transformer unit shipments were down 30 percent but up substantially in price, reflecting higher material costs.

b. Liquid-immersed, three-phase distribution transformer unit shipments were down 37.5 percent but up in both price and average size, with significant increases in data center applications.

c. Low-voltage, dry-type distribution transformer unit shipments were down 33 percent as a reflection of the units largely being short lead-time, off-the-shelf items that are easily defrayed in tight business conditions for better times.

d. Medium-voltage, dry-type distribution transformer unit shipments were actually up in 2009 compared to past years. This is attributable to the fact that these are long lead-time items, and many were ordered during the high economic growth period in 2008. Additionally, some purchases were likely expedited in 2009 to beat the DOE energy conservation standards that took effect in the beginning of 2010.

3.6 MANUFACTURERS OF DISTRIBUTION TRANSFORMERS

In total, there are more than 60 manufacturers and importers of distribution transformers operating in the U.S. today.[1] Of these, 16 major companies represent about 80 percent of both the liquid-immersed and dry-type markets.

From a manufacturing point of view, the six largest companies operating in the liquid-immersed distribution transformer market are (in alphabetical order): ABB Power T&D Company, Cooper Power Systems, Electrical Repair and Maintenance Company (ERMCO), Howard Industries, Power Partners, and Prolec-General Electric. Together, these six companies represent more than 80 percent of the sales revenue of liquid-immersed distribution transformers in the United States.

For low-voltage dry-type distribution transformer manufacturers, the seven largest companies operating in the United States include (in alphabetical order): Acme Electric Corporation, Eaton Electrical, Inc., Federal Pacific Transformer Company, General Electric, Hammond Power Solutions Inc., Olsun Electrics Corporation, and Square D Company. Together, these companies represent more than 80 percent of the sales revenue of low-voltage dry-type distribution transformers in the U.S.

For medium-voltage dry-type distribution transformers manufacturers, the seven largest companies operating in the U.S. include (in alphabetical order): ABB Power T&D Company, Federal Pacific Transformer Company, Hammond Power Solutions Inc., Jinpan International Ltd., Magnetic Technologies Corp., MGM Transformer Company, and Olsun Electrics

[1] This estimate is based on a review of the Thomas Business Registry (June 2005), United Laboratories (UL) Listings (June 2005), Canadian Standards Association (CSA) Listings (June 2005), Factory Mutual (FM) Listings (June 2005), the ORNL contact database from the Determination Analysis, and participants in DOE's Distribution Transformers Framework Workshop meeting held November 1, 2000 in Washington, DC.

Corporation. Together, these companies represent more than 80 percent of the sales revenue of medium-voltage dry-type distribution transformers in the United States.

3.6.1 Potential Small Business Impacts

DOE is considering the possibility of small businesses being impacted by the promulgation of minimum efficiency standards for distribution transformers. DOE is aware that there are small distribution transformer manufacturers, defined by the Small Business Administration as having 750 employees or fewer, who would be impacted by a minimum efficiency standard. DOE studies the potential impacts to these small businesses in greater detail during the manufacturer impact analysis (MIA)..Please see Chapter 12 for greater detail on this analysis.

3.6.2 Distribution and Sales Channels

A schematic of the distribution transformer market is shown in Figure 3.6.1.[i] This illustration depicts the major market players and the level of interaction between them. The solid lines show more common distribution and sales channels and dashed lines less frequently used channels.

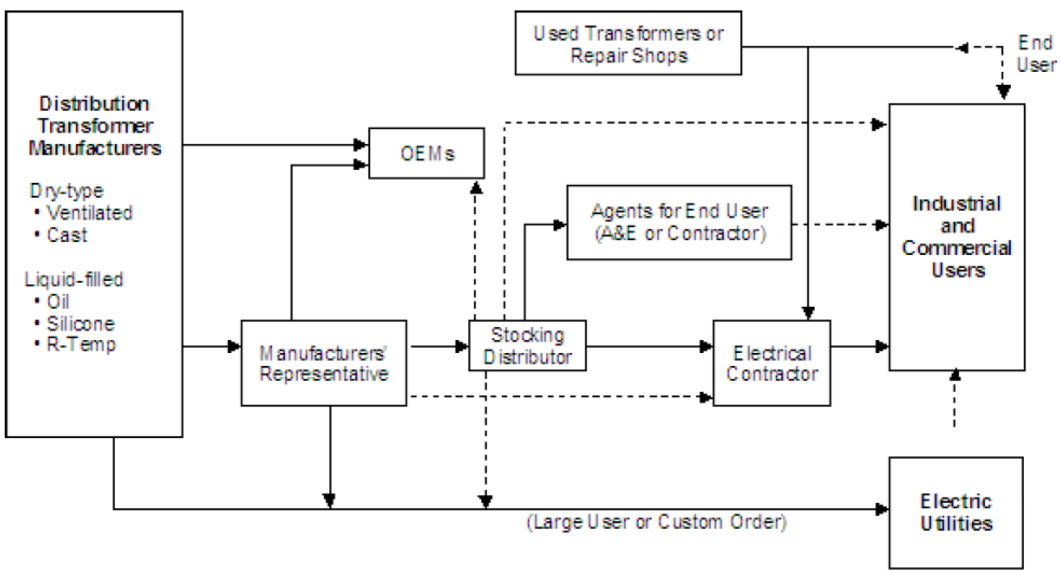

Figure 3.6.1 Market Delivery Channels for Distribution Transformers

The market delivery channel for electric utilities is generally direct, with the majority of these customers placing orders directly with manufacturers. It is estimated that electric utilities purchase over 90 percent of their distribution transformers directly from manufacturers, specifying their desired features and performance.[i] There are also utilities, such as some rural cooperatives and municipalities, that make transformer purchases through distributors. When placing an order, the electric utility provides a specification, including the value it places on future core and coil losses over the life of the transformer (see section 3.7 for a discussion of total owning cost). This market dynamic leads manufacturers to develop custom designs in their contract bids, reflecting the customer's performance requirements and the dynamic costs of material, equipment, and labor at a transformer manufacturer's facility.

The delivery channel for commercial and industrial customers can be complex, working through intermediaries such as stocking distributors and electrical contractors. Electrical contractors typically purchase transformers using specifications written by themselves or by agents. Some larger industrial customers buy transformers directly from distributors or manufacturers based on specifications drafted by in-house experts. Any large-volume or custom-order purchases made (e.g., orders from the petrochemical or the pulp and paper industry) are typically made directly with transformer manufacturers. Similarly, original equipment manufacturers (OEMs) know the exact specifications they require for their finished equipment and typically work directly with manufacturers when placing an order.

Transformers with major damage are usually replaced rather than repaired. However, when a repair does take place (e.g., when failure occurs within the warranty period), it may be carried out by a repair shop or at the manufacturer's facility. Additionally, some utilities may choose to carry out their own repairs if this option is less expensive than disposal and replacement.

3.7 TOTAL OWNING COST EVALUATION

In 1995, there were an estimated 44 million liquid-immersed distribution transformers in service, of which approximately 90 percent were owned by electric utilities.[i] For dry-type transformers, there were approximately 12 million units in service, which were primarily used by commercial and industrial customers.[i] The liquid-immersed market, dominated by the electric utility sector, drove efficiency ratings higher over time, encouraging more efficient materials and manufacturing methods. A detailed discussion of these improvements and efficiency trends between the years 1950 and 1993 can be found in two Oak Ridge National Laboratory (ORNL) reports.[i,ii]

Following the energy price shocks of the 1970s, utilities started using total owning cost (TOC) evaluation formulas (Equation 3.7.1), incorporating core and winding losses into their purchasing decisions. The TOC consists of the quoted transformer price and energy losses in the core and winding over the anticipated life of the unit.

Expressed as a formula,

Equation 3.7.1

$$TOC = (NL \times A) + (LL \times B) + Price$$

where:

TOC = total owning cost ($),
NL = no-load loss (Watts),

A = equivalent first-cost of no-load losses ($/Watt),
LL = load loss at the transformer's rated load (Watts),
B = equivalent first-cost of load losses ($/Watt), and
$Price$ = bid price (retail price)($).

The capitalized cost per watt of no-load and load losses, the A and B factors, vary from one electric utility to another. They are derived from several variables, including the avoided costs of system capacity, generation capacity, transmission and distribution capacity and energy, the levelized fixed charge rate, the peak responsibility factor, the transformer loss factor, and the equivalent annual peak load.[iii] For a detailed discussion on the development and use of the TOC formula, including examples, see the draft industry standard document, Institute of Electrical and Electronics Engineers, Inc. (IEEE) PC57.12.33.

Utilities that use A and B factors compare two or more proposals from manufacturers and select the one that offers them the lowest total owning cost (i.e., the lowest combination of first cost and operating cost over the life of the transformer). Before electric utility deregulation started in North America, 30 years was considered the standard operating life and the depreciation period of a liquid-immersed transformer. Deregulation has raised concerns about payback periods, since electric utilities are not sure if they will own the transformer for its entire life. This uncertainty has forced some electric utilities to reduce their A and B factors, equating to a decreased emphasis on losses and, therefore, transformer efficiency ratings.

In 1996, ORNL estimated that "more than 90 percent" of electric utilities used the TOC method of loss evaluation at the time of purchase, which drove the market toward increasingly efficient designs.[i] More recently, however, the possibility of deregulation and the associated sale of distribution networks has meant that utilities purchasing transformers today may not own them in 5 or 10 years, and thus will not recover the higher initial cost of a more efficient design. These regulatory changes and the general uncertainty surrounding deregulation have driven some utilities to purchase designs with lower first costs and higher losses.

Similarly, DOE's final rule for distribution transformers that was published in October 2007 has caused some utilities to reexamine their A and B factors. DOE is aware that some utilities have deemphasized the importance of A and B factors and placed more emphasis on lower first costs as a result of the minimum efficiency standards. Through conversations with industry professionals and manufacturers, DOE believes that many utilities still maintaince awareness of a total owning cost approach, but sometimes find that such an approach would dictate an efficiency level below the federal standard and therefore purchase at that threshold. Furthermore, many utilities have critically examined their A and B factors in response to the 2007 rulemaking, and have altered their A and B factors in response.

The IEEE draft standard PC57.12.33 has a chapter discussing transformer efficiency for commercial and industrial customers[iii] (i.e., typical users of dry-type transformers), but the market itself appears split between the medium-voltage and the low-voltage units. The medium-voltage, dry-type transformer market functions similarly to the liquid-immersed market, in that manufacturers receive custom-build orders with specifications or design criteria from customers. Because these customers pay for (and are concerned about) the electricity lost in their own distribution systems, they are concerned about the performance of the transformers they order. The low-voltage, dry-type transformer market does not participate in the manufacturing process; instead these units are generally sold "off-the-shelf" or on a catalog stock order basis. Most of the low-voltage, dry-type transformers installed inside buildings or plants are purchased by electrical contractors or building managers who are not responsible for paying future energy bills. Thus, the designs of these transformers are commonly driven toward the lowest first-cost, lower efficiency units. This trend was identified by ORNL.[i]

3.8 VOLUNTARY PROGRAMS

DOE reviewed several voluntary programs promoting efficient distribution transformers in the United States. When DOE's previous rulemaking for distribution transformers took effect in January of 2010, many voluntary programs ended. This is because the minimum efficiency requirements were greater than or equal to the efficiency level dictated by the voluntary program, or the program needed revising in light of the new standard levels.

In this section, DOE considers several voluntary programs that are still operating, and several programs that recently became inactive. These include the NEMA Standards Publication TP 1, *Guide for Determining Energy Efficiency for Distribution Transformers*, (NEMA TP 1) and NEMA Premium Standard, the Federal Energy Management Program's TP 1 purchase program, the U.S. Environmental Protection Agency's Energy Star Transformers program, and the Consortium for Energy Efficiency's Commercial and Industrial Transformers Initiative. DOE also reviewed several voluntary programs operating at a regional level that offer custom incentive programs for distribution transformers, such as the programs offered by National Grid and Seattle City Light.

3.8.1 National Electrical Manufacturers Association TP 1 Standard

The NEMA TP 1 standard established a voluntary efficiency standard for distribution transformers.[iv] It encompassed liquid-immersed distribution transformers, single- and three-phase, as well as dry-type, low-voltage and medium-voltage, single- and three-phase units. The efficiency levels for liquid-immersed and medium-voltage dry-type distribution transformers were superseded, though, by DOE's final rule, published in October 2007. Additionally, Congress established NEMA TP 1 as the standard for low-voltage dry-type transformers (EPACT 2005, August 8, 2005). Therefore, the NEMA TP 1 standard levels are no longer voluntary, but required.

NEMA established this national voluntary efficiency standard in 1996, and revised it in 2002.[v] Manufacturers had to meet or exceed the minimum efficiency targets presented in Table 3.8.1 and Table 3.8.2 at the appropriate loading points. At that time, NEMA TP 1 efficiency levels were adopted by States and other agencies that were interested in establishing a standard. More information about NEMA TP 1 can be obtained by contacting NEMA, tel: 703-841-3200, or by visiting http://www.nema.org/stds/tp1.cfm#download .

Table 3.8.1 National Electrical Manufacturers Association TP 1 Efficiency Levels for Liquid-Immersed Distribution Transformers

Liquid-Immersed, Single-Phase		Liquid-Immersed, Three-Phase	
kVA	**Min Efficiency (%)**	**kVA**	**Min Efficiency (%)**
10	98.3	15	98.0
15	98.5	30	98.3
25	98.7	45	98.5
37.5	98.8	75	98.7
50	98.9	112.5	98.8
75	99.0	150	98.9
100	99.0	225	99.0
167	99.1	300	99.0
250	99.2	500	99.1
333	99.2	750	99.2
500	99.3	1000	99.2
667	99.4	1500	99.3
833	99.4	2000	99.4
-	-	2500	99.4

Notes: Temperature: load-loss 85˚ C, no-load loss 20˚ C
Efficiency levels at 50 percent of unit nameplate load

Table 3.8.2 National Electrical Manufacturers Association TP 1 Efficiency Levels for Dry-Type Distribution Transformers

Dry-Type, Single-Phase				Dry-Type, Three-Phase			
kVA	**Min Efficiency (%)**			**kVA**	**Min Efficiency (%)**		
	Low-Voltage	**Medium-Voltage**			**Low-Voltage**	**Medium-Voltage**	
		≤60 kV BIL	**>60 kV BIL**			**≤60 kV BIL**	**>60 kV BIL**
15	97.7	97.8	97.6	15	97.0	97.2	96.8
25	98.0	98.1	97.9	30	97.5	97.6	97.3
37.5	98.2	98.3	98.1	45	97.7	97.8	97.6
50	98.3	98.4	98.2	75	98.0	98.1	97.9
75	98.5	98.5	98.4	112.5	98.2	98.3	98.1
100	98.6	98.6	98.5	150	98.3	98.4	98.2
167	98.7	98.8	98.7	225	98.5	98.5	98.4
250	98.8	98.9	98.8	300	98.6	98.6	98.5
333	98.9	99.0	98.9	500	98.7	98.8	98.7
500	-	99.1	99.0	750	98.8	98.9	98.8
667	-	99.2	99.0	1000	98.9	99.0	98.9
833	-	99.2	99.1	1500	-	99.1	99.0
-	-	-	-	2000	-	99.2	99.0
-	-	-	-	2500	-	99.2	99.1

Notes: Temperature: 75˚ C for both low- and medium-voltage
Low-voltage efficiency levels at 35 percent of unit nameplate load
Medium-voltage efficiency levels at 50 percent of unit nameplate load

3.8.2 National Electrical Manufacturers Association – NEMA Premium Program

The NEMA Premium program establishes a voluntary efficiency standard for low-voltage, dry-type distribution transformers. It encompasses both single- and three-phase low-voltage, dry-type units. For a low-voltage, dry-type distribution transformer to qualify as NEMA

Premium, it must have 30 percent fewer losses than the NEMA TP 1 level. NEMA established this national voluntary efficiency program in July 2010. Manufacturers must meet or exceed the minimum efficiency targets presented in Table 3.8.3 at the appropriate loading points. More information about NEMA Premium can be obtained by contacting NEMA, tel: 703-841-3200, or by visiting http://www.nema.org/gov/energy/efficiency/premium/transformersProgram.cfm.

Table 3.8.3 NEMA Premium Efficiency Levels for Low-Voltage, Dry-Type Distribution Transformers

Single-Phase		Three-Phase	
kVA	**Min Efficiency (%)**	**kVA**	**Min Efficiency (%)**
15	98.39	15	97.90
25	98.60	30	98.25
37.5	98.74	45	98.39
50	98.81	75	98.60
75	98.95	112.5	98.74
100	99.02	150	98.81
167	99.09	225	98.95
250	99.16	300	99.02
333	99.23	500	99.09
-	-	750	99.16
-	-	1000	99.23

Note: Efficiency levels at 35 percent of unit nameplate load.

3.8.3 Energy Star Transformers

The U.S. Environmental Protection Agency (U.S. EPA) and DOE managed a program called Energy Star Transformers to overcome market barriers preventing industrial/commercial customers and utilities from purchasing more energy-efficient, dry-type, low-voltage, single- and three-phase units. The minimum efficiency that a transformer had to meet or exceed to be classified as an Energy Star transformer was the same as NEMA's TP 1. The activities of this program included use of the Energy Star label, marketing assistance to manufacturers and distributors, and free software tools for end users (including a downloadable cost evaluation model and an energy-efficiency calculator). This program was sponsored and promoted by the U.S. EPA and DOE, with additional promotional support from the Consortium for Energy Efficiency (CEE).

The Energy Star Transformers program was suspended on May 1, 2007 because EPACT 2005 established NEMA TP 1 as the standard for low-voltage dry-type transformers. For more information or questions about this program, please contact the U.S. EPA tel: 1-888-STAR-YES or visit http://www.epa.gov/; or CEE, tel: 617-589-3949, or visit http://www.cee1.org/.

3.8.4 Consortium for Energy Efficiency

The CEE's Commercial and Industrial Transformers Initiative, launched in 1997, promoted the manufacture and sale of high-efficiency transformers. Historically, CEE and its members partnered with the Energy Star Transformers Program to promote high-efficiency performance guidelines for low-voltage distribution transformers specified by the NEMA TP 1 standard. CEE members and other participating organizations include electric utilities, and statewide or regional efficiency organizations, which may be utility-based. CEE published an *Initiative Description and Market Assessment*, which identifies the transformer market barriers to efficiency for interested utilities and other organizations. In 2012 CEE was updating its high-efficiency transformer specification. For more information, contact CEE at tel: 617-337-9274.

3.8.5 Federal Energy Management Program

DOE manages the Federal Energy Management Program (FEMP), which helps Federal buyers identify and purchase energy-efficient equipment, including distribution transformers. The FEMP standard for distribution transformers is based on the NEMA TP 1 standard, and includes all units listed in TP 1. While the liquid-immersed and medium-voltage dry-type recommendations (based on NEMA TP 1) are superseded by DOE's 2007 final rule, FEMP still offers buyers support tools such as efficiency guidelines, cost-effectiveness examples, and a cost calculator. FEMP also offers training, on-site audits, demonstrations, and design assistance. For more information, interested stakeholders can contact FEMP at tel: 1-202-586-5772, or visit http://www1.eere.energy.gov/femp/.

3.8.6 National Grid

National Grid offers a custom measure incentive for energy efficient replacement distribution transformers. Each transformer purchase is evaluated independently based on first costs and energy savings (annually and during peak loading) compared to the existing transformer. If the replacement distribution transformer passes National Grid's custom criteria, up to 50 percent of the first costs can be reimbursed, capped at a 1.5 year payback and based on a dollar cost per unit of savings. For more information, contact National Grid at 1-781-907-1000 or efficiency@us.ngrid.com.

3.8.7 Seattle City Light

Seattle City Light manages the Energy Smart Services Custom Incentive Program.[vi] The program provides incentives for distribution transformers that exceed the NEMA TP 1 standards for low-voltage, dry-type distribution transformers. Incentives provided cover up to 70 percent of the cost for qualifying equipment, or $0.23 per kilowatt-hour saved. Usually incentives are applied to utility-owned equipment. For more information contact Seattle City Light at tel: 206-684-3000, or visit www.seattle.gov/light/.

3.9 REGULATORY PROGRAMS

On August 8, 2005 the President signed into law EPACT 2005. This legislation established the energy conservation standard for low-voltage, dry-type distribution transformers at the industry voluntary program level of NEMA TP 1-2002. This Federally mandated standard is the national standard, preempting any State efficiency standards for this type of equipment when it took effect on January 1, 2007. At the international level, DOE is aware of standards in both Canada and Mexico that may impact the companies servicing the North American market. Summaries of these regulatory programs are provided in this section.

3.9.1 U.S. National Energy Bill – Energy Policy Act of 2005

The U.S. Congress enacted legislation requiring that low-voltage, dry-type transformers manufactured on or after, or imported into the U.S. on or after January 1, 2007, meet the NEMA TP 1 minimum efficiency standards:

> LOW VOLTAGE DRY TYPE DISTRIBUTION TRANSFORMERS.—The efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2007, shall be the Class I Efficiency Levels for distribution transformers specified in table 4–2 of the 'Guide for Determining Energy Efficiency for Distribution Transformers' published by the National Electrical Manufacturers Association (NEMA TP–1–2002).

During DOE's previous rulemaking on distribution transformers, DOE adopted the NEMA TP 1-2002 standard level set by EPACT 2005. As such, DOE no longer considered low-voltage, dry-type transformers in that analysis, and published a final rule in 2007 that contained new standards for only liquid-immersed and medium-voltage, dry-type units. At this point in time, DOE has revisited low-voltage, dry-type distribution transformers to see if higher standard levels are warranted.

3.9.2 Canadian Efficiency Standard

The Canadian Government regulates efficiency of dry-type transformers. The regulation mandates compliance with the efficiency values listed in Canadian Standards Association (CSA) standard C802.2-00 as of January 1, 2005 (Canada Gazette, April 10, 2003). Liquid-immersed distribution transformers are addressed by a voluntary program, which has been drafted to allow supervisory oversight by the Canadian Government.

In June 1997, the Office of Energy Efficiency at Natural Resources Canada (NRCan) announced that it intended to develop regulated minimum performance standards for transformers. These proposed regulations would affect interprovincial trade and transformers imported into Canada. Consultative workshops followed this announcement, which included discussion around harmonizing with NEMA's TP 1 levels.

The CSA drafted and published *CSA C802.2-Minimum Efficiency Values for Dry Type Transformers*, in which efficiency is measured according to a per unit loading of 35 percent for low-voltage and 50 percent for medium-voltage. The efficiency levels are the same as NEMA TP 1 except the CSA added an additional significant digit (zero) in the hundredths place. For this standard, the reference winding temperature is 75˚C, as in NEMA's TP 1. An amendment proposed in June 2010 would result in increasing the standard levels for medium-voltage dry-type to align with the current DOE standards. At the publication of this document, however, NRCan MVDT standards remained below those of DOE.

As a result of the process of working with the CSA and a range of stakeholders, NRCan chose to separate the regulatory processes for liquid-immersed and dry-type transformers.

Liquid-Immersed Transformer Standards

The process of regulating minimum efficiency levels for liquid-immersed transformers was stopped after several years of development. The CSA harmonized the Canadian standard with NEMA's voluntary standards, selecting the range of regulated equipment, the efficiency levels, and the transformer test procedures based on NEMA TP 1 and TP 2. However, a market analysis revealed that the liquid-immersed transformer market in Canada is dominated by the nine provincially operated electric utilities, each of which had already incorporated energy efficiency into their transformer procurement practices. It was found that more than 95 percent of the liquid-immersed distribution transformers sold in Canada already met the NEMA TP 1 efficiency levels.

Thus, the Canadian Government decided not to continue with the development of a regulation for liquid-immersed distribution transformers. Instead, the major Canadian utilities and manufacturers, through the Canadian Electricity Association (CEA), signed a voluntary agreement with NRCan. Under the terms of this agreement, the electric utilities agreed to adopt the minimum efficiency levels based on the CSA C802.1-00 standard when purchasing liquid-filled transformers, and to report the performance of virtually all liquid-immersed transformers installed in Canada to NRCan. NRCan will then determine if the efficiency of the market is degrading and, if so, take appropriate action.

Dry-Type Transformer Standards

NRCan pre-published an amendment to Canada's regulations that includes dry-type transformers on December 14, 2002. This amendment was published on April 23, 2003. This minimum energy performance standard for dry-type transformers became effective on January 1, 2005. The regulations included a broad range of kVA ratings, more than are included in NEMA TP 1 or the Department of Energy's rulemaking on distribution transformers.

A consultation forum was organized in June 2005 by NRCan with the objective of analyzing some issues pertaining to the Canadian regulation. As a result of this focus, some changes were made to the regulation and modifications proposed to the CSA C802.2 Standard. Meetings were convened in July and September 2005 involving of NRCan, the CSA C802.2 subcommittee, transformer manufacturers and other stakeholders to address these issues. At these meetings, some of the key changes to the dry-type transformer regulation agreed were:

- Elimination of the tap range exemption, so there is no exemption in the Canadian regulations based on a tap range.

- Addition of an exemption for furnace transformers. This exemption was necessary due to the removal of the tap range exemption. Furnace transformers were defined as "a three-phase step-down transformer that is designed to be connected to an electric-arc furnace, and has a delta-wye switching arrangement plus high-voltage taps for changing the level of the low voltage supplied to the furnace."

- Exclusion of drive transformers with two or more output windings or a low-voltage line current larger than 1500 amperes. This means that drive transformers designed with one output winding and a low-voltage line current less than or equal to 1500 Amperes are subject to regulation.

- Clarification that transformers with resin-cast coils (not encapsulated cores) are covered by the regulation. The exemptions for sealed transformers and non-ventilated transformers do not apply to resin-cast coil transformers.

- Elimination of the minimum low-voltage values, and addition of a maximum low-voltage line current of 4000 amperes.

In addition, the following change was made to the CSA dry-type performance standard, and this change may be incorporated in the Energy Efficiency Regulations in a future amendment:

- Adoption of two BIL groupings for medium-voltage dry-type transformers, consistent with the BIL groupings in NEMA TP 1-2002.

At the September 2005 meeting, an amendment to the definition of a dry-type transformer was also agreed as follows:

Dry-type transformer means a transformer, including a transformer that is incorporated into any other product, in which the core and coils are in a gaseous or dry compound insulating medium and that

(a) is either single-phase with a capacity from 15 to 833 kVA or three-phase with a capacity from 15 to 7500 kVA, and
(b) has a nominal frequency of 60 Hz,

but does not include transformers having a rated low voltage line current larger than 4000 amperes.

Additional amendments were made by NRCan in the following years, and most recently in June 2010, NRCan pre-published proposed amendments to regulations. (Canada Gazette Part I, June 12, 2010) The amendments proposed the following changes:

- Increase existing standards for single- and three-phase dry-type transformers to harmonize with DOE standards.

- Increase the scope of coverage to include transformers with a BIL up to 199 kVA. DOE's standards have an upper limit of 150 kVA.

- Adopt exclusions for the following transformers: special impedance, grounding, furnace, resistance grounding, and on-load regulating.

- Remove exclusions for "transformers with tap ranges of 20%, uninterruptible power supply transformers, instrument transformers, machine tool (control) transformers, and encapsulated transformers."

- "Scale efficiency values for three-phase units with a rating between 3,000 to 7,500 kVA," which are not covered by the U.S. standards.

- Adopt a "more stringent table of normal impedance ranges (i.e., units with an impedance level that fell outside the normal impedance ranges would be excluded from the [minimum efficiency performance standards])."

Table 3.9.1 presents the current efficiency requirements for dry-type transformers.
Table 3.9.2 presents the proposed revised efficiency requirements for medium-voltage dry-type transformers.

Table 3.9.1 Canadian Efficiency Regulations for Dry-Type Transformers

Single-Phase				Three-Phase			
kVA	**Minimum Low Voltage (V)**	**1.2 kV Class Efficiency (%), at 35% Loading**	**BIL 20-150kV Efficiency (%), at 50% Loading**	**kVA**	**Minimum Low Voltage (V)**	**1.2 kV Class Efficiency (%), at 35% Loading**	**BIL 20-150kV Efficiency (%), at 50% Loading**
15	120/240	97.70	97.60	15	208Y/120	97.00	96.80
25	120/240	98.00	97.90	30	208Y/120	97.50	97.30
37.5	120/240	98.20	98.10	45	208Y/120	97.70	97.60
50	120/240	98.30	98.20	75	208Y/120	98.00	97.90
75	120/240	98.50	98.40	112.5	208Y/120	98.20	98.10
100	120/240	98.60	98.50	150	208Y/120	98.30	98.20
167	120/240	98.70	98.70	225	208Y/120	98.50	98.40
250	120/240	98.80	98.80	300	208Y/120	98.60	98.50
333	120/240	98.90	98.90	500	208Y/120	98.70	98.70
500	480	-	99.00	750	208Y/120	98.80	98.80
667	480	-	99.00	1000	208Y/120	98.90	98.90
833	480	-	99.10	1500	480Y/277	-	99.00
-	-	-	-	2000	480Y/277	-	99.00
-	-	-	-	2500	480Y/277	-	99.10
-	-	-	-	3000	600Y/347	-	99.10
-	-	-	-	3750	4160Y/2400	-	99.20
-	-	-	-	5000	4160Y/2400	-	99.20
-	-	-	-	7500	4160Y/2400	-	99.20

Table 3.9.2 Proposed Revised Canadian Efficiency Regulations for Medium-Voltage Dry-Type Transformers

Single-Phase Efficiency (%)				Three-Phase Efficiency (%)			
kVA	**20-45kV BIL**	**46-95kV BIL**	**96-199kV BIL**	**kVA**	**20-45kV BIL**	**46-95kV BIL**	**96-199kV BIL**
15	98.10	97.86	97.6	15	97.50	97.18	96.80
25	98.33	98.12	97.9	30	97.90	97.63	97.30
37.5	98.49	98.30	98.10	45	98.10	97.86	97.60
50	98.60	98.42	98.20	75	98.33	98.12	97.90
75	98.73	98.57	98.53	112.5	98.49	98.30	98.10
100	98.82	98.67	98.63	150	98.60	98.42	98.20
167	98.96	98.83	98.80	225	98.73	98.57	98.53
250	99.07	98.95	98.91	300	98.82	98.67	98.63
333	99.14	99.03	98.99	500	98.96	98.83	98.80
500	99.22	99.12	99.09	750	99.07	98.95	98.91
667	99.27	99.18	99.15	1,000	99.14	99.03	98.99
833	99.31	99.23	99.20	1,500	99.22	99.12	99.09
-	-	-	-	2,000	99.27	99.18	99.15
-	-	-	-	2,500	99.31	99.23	99.20
-	-	-	-	3,000	99.34	99.26	99.24
-	-	-	-	3,750	99.38	99.30	99.28
-	-	-	-	5,000	99.42	99.35	99.33
-	-	-	-	7,500	99.48	99.41	99.39

Note: At 50 percent unit nameplate load.

3.9.3 Mexican Efficiency Standard

Mexico is one of the regional leaders in promoting and regulating energy efficient transformers. In recent years, other countries, such as Argentina, Ecuador, and Peru, have requested assistance from Mexico in the development and implementation of national efficiency programs.

Mexico began regulating distribution transformers more than three decades ago when it enacted NOM-J116 in 1977.[vii] However, in 1989, a presidential decree modified the Normas Oficiales Mexicanas (Official Mexican Standards) from mandatory to voluntary standards; NOM-J116 became NMX-J116, a Norma Mexicana (Mexican Standard). In 1992, the Ley Federal sobre Metrología y Normalización (Federal Law on Metering and Standards) re-established the mandatory character of NOMs. In addition, this law empowered the Secretaría de Energía (the Mexican equivalent to the U.S. Department of Energy) to formulate and enact mandatory standards for electrical equipment.

A new mandatory standard was enacted in 1994, NOM-001-SEMP-1994, to regulate the energy efficiency and safety of electrical equipment including distribution transformers. In 1997, Mexico's government proposed a revision to NOM-001, and also proposed a new standard, NOM-002-SEDE-1997.[viii] NOM-002 was published in the Diario Oficial de la Federación (Official Registry) for public revision and enacted two years later in October 1999.

In 2010, NOM-002 was revised to update several aspects of the standard. The new version of the document, NOM-002-SEDE-2010, was approved by the Comité Consultivo Nacional de Normalización de Instalaciones Eléctricas (CCNNIE) on July 8, 2010. Once it is published in the Diario Oficial de la Federación, the new standard will take effect six months later.

This standard, which regulates liquid-immersed units, is the only compulsory efficiency regulation of distribution transformers in Mexico. Dry-type distribution transformers are used in Mexico, but neither government nor industry has moved to regulate them. Table 3.9.3 presents the characteristics of regulated distribution transformers in Mexico.

Table 3.9.3 Characteristics of Regulated Distribution Transformers in Mexico

Characteristic	Specification
Power Supply	Single-phase Three-phase
Nominal Capacity	5 to 167 kVA (single-phase) 15 to 500 kVA (three-phase)
Insulation Class	Up to 95 kV BIL (Up to 15 kV) Up to 150 kV BIL (Up to 25 kV) Up to 200 kV BIL (Up to 34.5 kV)
Installation Application	Pad; Pole; Substation; Submersible
Status of Transformer	Newly purchased Repaired/Refurbished

NOM-002 provides two sets of tables with the specified minimum efficiency levels and the unit losses in watts, both tested at 100 percent of nameplate load. Since the requirements in NOM-002 are based on 100 percent loading, they are not directly comparable to DOE's efficiency standards. Table 3.9.4 and Table 3.9.5 show the efficiency requirements under NOM-002, which were left unchanged in the 2010 revision of the standard. However, while the previous version of NOM-002 allowed a less stringent standard for small manufacturers with cumulative annual production under 9 kVA, the 2010 version has removed this provision. This is partially because the reduced standards for small manufacturers were not typically applied in practice, and many small manufacturers were complying at the same efficiency level as the large manufacturers.

While there is only one mandatory standard for distribution transformers, there are several voluntary Mexican standards. This description only deals with the mandatory standards.

Table 3.9.4 Minimum Efficiency Levels for Transformers in Mexico

Type	Capacity [kVA]	Insulation Class		
		Up to 95 kV BIL (Up to 15 kV) [%]	Up to 150 kV BIL (Up to 25 kV) [%]	Up to 200 kV BIL (Up to 34.5 kV) [%]
Liquid-Immersed, Single-Phase	5	97.90	97.80	97.70
	10	98.25	98.15	98.05
	15	98.40	98.3	98.2
	25	98.55	98.45	98.35
	37.5	98.65	98.55	98.45
	50	98.75	98.65	98.55
	75	98.90	98.80	98.70
	100	98.95	98.85	98.75
	167	99.00	98.90	98.80
Liquid-Immersed, Three-Phase	15	97.95	97.85	97.75
	30	98.25	98.15	98.05
	45	98.35	98.25	98.15
	75	98.50	98.40	98.30
	112.5	98.60	98.50	98.40
	150	98.70	98.60	98.50
	225	98.75	98.65	98.55
	300	98.80	98.70	98.60
	500	98.90	98.80	98.70

Note: These efficiency levels are applicable at 100 percent of nameplate load, and do not include losses from protective accessories.

Table 3.9.5 Maximum Allowed Losses for Transformers in Mexico

Type	Capacity [kVA]	Insulation Class: Up to 95 kV BIL (Up to 15 kV) [Watts]		Up to 150 kV BIL (Up to 25 kV) [Watts]		Up to 200 kV BIL (Up to 34.5 kV) [Watts]	
		Core Losses	Total Losses	Core Losses	Total Losses	Core Losses	Total Losses
Liquid-Immersed, Single-Phase	5	30	107	38	112	63	118
	10	47	178	57	188	83	199
	15	62	244	75	259	115	275
	25	86	368	100	394	145	419
	37.5	114	513	130	552	185	590
	50	138	633	160	684	210	736
	75	186	834	215	911	270	988
	100	235	1061	265	1163	320	1266
	167	365	1687	415	1857	425	2028
Liquid-Immersed, Three-Phase	15	88	314	110	330	135	345
	30	137	534	165	565	210	597
	45	180	755	215	802	265	848
	75	255	1142	305	1220	365	1297
	112.5	350	1597	405	1713	450	1829
	150	450	1976	500	2130	525	2284
	225	750	2844	820	3080	900	3310
	300	910	3644	1000	3951	1100	4260
	500	1330	5561	1475	6073	1540	6586

Note: These losses are applicable at 100 percent of nameplate load, and do not include losses from protective accessories.

It is important to note that Mexican efficiency standards represent an absolute minimum efficiency for each unit that is sold. According to the standards, every transformer must be within the minimum requirement, whereas U.S. DOE requirements provide a tolerance that is applicable to the transformers depending on the number of units built. Therefore, manufacturers selling in Mexico must apply a design margin to account for the statistical variation on loss measurements. Typically, this margin is around 6 percent of the maximum total losses, which decreases the average losses of the manufacturer’s units by 6 percent compared to the efficiency requirement.

In practice, however, many distribution transformers sold in Mexico exceed the minimum efficiency requirement. Unlike the United States, utility services in Mexico are provided by a single, public utility called Comisión Federal de Electridad (CFE). Due to the high loss evaluation formula that CFE uses, many manufacturers produce transformers with losses that are 20 percent or more below the minimum requirement.

3.10 TECHNOLOGY ASSESSMENT

A transformer is a device constructed with two primary components: a magnetically permeable core, and a conductor of a low-resistance material wound around that core. A distribution transformer's primary function is to change alternating current from one voltage (primary) to a different voltage (secondary). It accomplishes this through an alternating magnetic field or "flux" created by the primary winding in the core, which induces the desired voltage in the secondary winding. The change in voltage is determined by the "turns ratio," or relative number of times the primary and secondary windings are wound around the core. If there are twice as many secondary turns as primary turns, the transformer is a step-up transformer, with a secondary voltage that would be double the primary voltage. Conversely, if the primary has twice as many turns as the secondary, the transformer is called a step-down transformer, with the secondary voltage half as much as the primary voltage. Distribution transformers are always step-down transformers.

Transformer losses are generally small, in the vicinity of a few percent or less of the total power handled by the transformer. There are two main kinds of losses in transformers: no-load (core) losses and load (winding) losses. Higher transformer efficiencies are achieved by reducing the losses associated with these two assemblies: the core and the windings.

3.10.1 Distribution Transformer Types

In general, there are two primary types of distribution transformer: liquid-immersed and dry-type. Liquid-immersed transformers typically use oil as both a coolant (removing heat from the core and coil assembly) and a dielectric medium (preventing electrical arcing across the windings). Liquid-immersed transformers are typically used outdoors because of concerns over oil spills or fire if the oil temperature reaches the flash-point level. In recent decades, new insulating liquid insulators (e.g., silicone fluid) have been developed which have a higher flash-point temperature than mineral oil, and transformers with these liquids can be used for indoor applications. However, high initial costs for these less-flammable, liquid-immersed transformers, relative to the cost of dry-type units, prevents widespread market adoption.

Dry-type transformers are air-cooled, fire-resistant devices that do not use oil or other liquid insulating/cooling media. Because air is the basic medium used for insulating and cooling and it is inferior to oil in these functions, dry-type transformers are larger than liquid-immersed units for the same voltage and/or kVA capacity. As a result, when operating at the same flux and current densities, the core and coil assembly is larger and hence incurs higher losses. Due to the physics of their construction (including the ability of these units to transfer heat), dry-type units have higher losses than liquid-immersed units. However, dry-type transformers are an important part of the transformer market because they can offer safety, environmental, and application advantages.

3.10.2 Transformer Efficiency Levels

There are two main types of losses in transformers: no-load (core) losses and load (winding) losses. Core losses are virtually constant with loading, occurring continuously in the core material to keep the transformer energized and ready to provide power at the secondary terminals. Core losses are present even if the load on the transformer is zero. Winding losses occur in the primary and secondary windings around the core, and increase as the square of the load applied to the transformer. Winding losses result primarily from the electrical resistance of the winding material.

Figure 3.10.1 depicts the change in core and coil losses with transformer loading on a 75 kVA dry-type transformer, built with copper windings and an 80 degree temperature rise. This illustration clearly shows the quadratic growth of the winding losses.

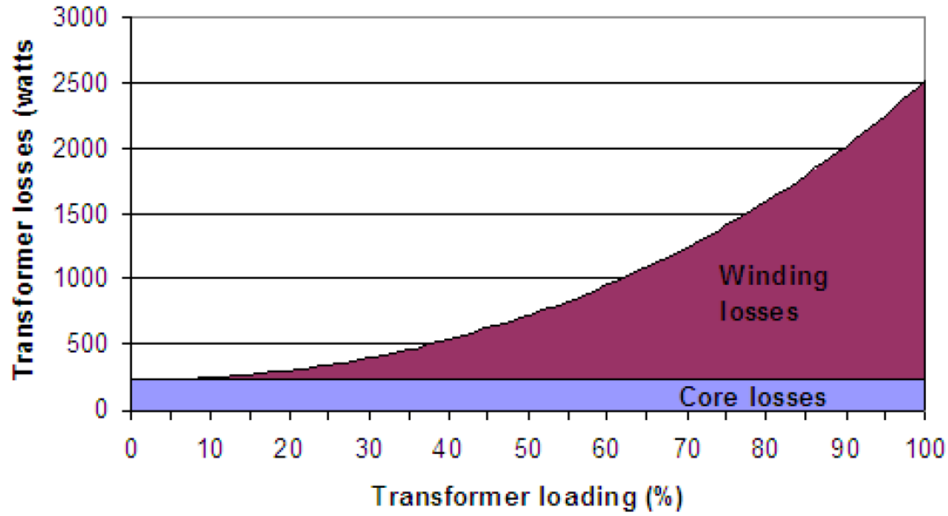

Figure 3.10.1 Transformer Losses Vary with Load (75 Kilovolt-Ampere Dry-Type)

The equation used to calculate the percent efficiency of a transformer at any loading point is given as follows (IEEE, C57.12.00):

Equation 3.10.1

$$EE_{load} = \left(\frac{100 \times P_{load} \times kVA \times 1000}{P_{load} \times kVA \times 1000 \times NL \times LL \times (P_{load})^2 \times T} \right)$$

where:

EE_{load} = percent efficiency at a given per unit load,
P_{load} = per unit load,
kVA = kVA rating of transformer,
NL = no-load loss (Watts),
LL = load loss (Watts), and
T = temperature correction factor.

As Equation 3.10.1 shows, the efficiency of a transformer is not a static value, but rather will vary depending on the per unit load (P_{load}) applied to the transformer. Using the losses plotted in Figure 3.10.1, DOE used Equation 3.10.1 to calculate the efficiency of this 75 kVA dry-type transformer at each loading point from 0 to 100 percent of nameplate load. The results are shown in Figure 3.10.2, which clearly indicates that the efficiency of a transformer is not constant, but rather varies with loading. The highest efficiency occurs at the loading point where core losses are equal to winding losses.

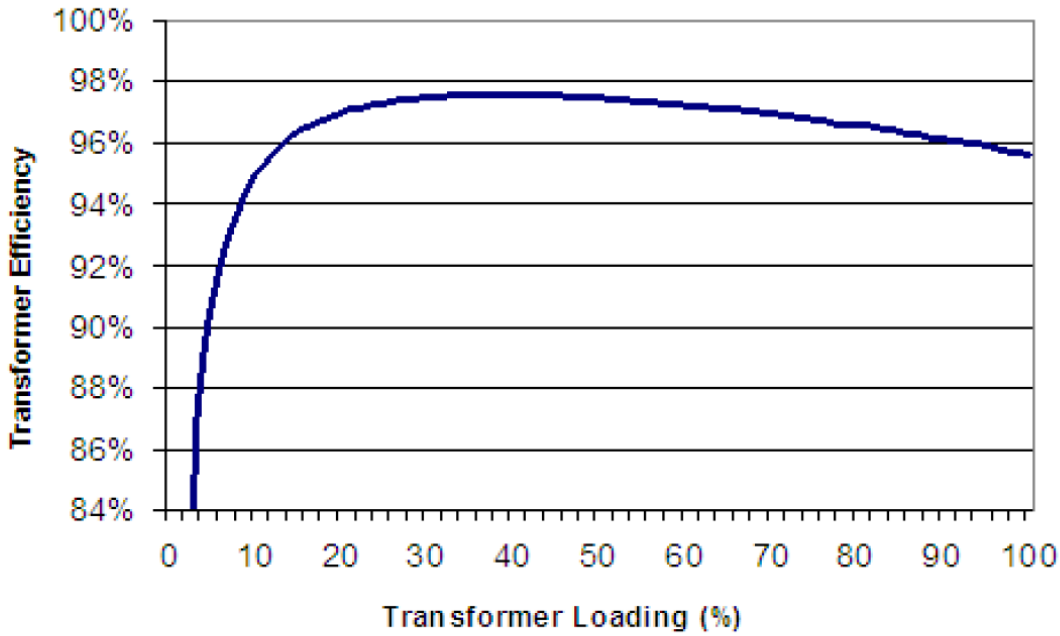

Figure 3.10.2 Transformer Efficiency Varies with Load

Consequently, any discussion of transformer efficiency must include an assumed loading point. Although DOE assumes a range of loading points in its analysis, (see the energy use and end-use load characterization sections in chapter 6 of this TSD) the DOE test procedure stipulates that a low-voltage dry-type distribution transformer must be tested at 35% load and medium-voltage dry-type and liquid-immersed distribution transformers must be tested at 50% load.

3.10.3 Transformer Losses

This section discusses methods to reduce transformer losses that have been developed over the 125 years of technology evolution. The physical principles of distribution transformer operation are discussed in detail in Chapter 2 of the *Determination Analysis of Energy Conservation Standards for Distribution Transformers*.[i] This section summarizes some of the main technological methods for reducing transformer losses.[ix]

Core losses occur in the core material of the distribution transformer, and are present whenever the transformer is energized – i.e., available to provide or providing load. Core losses are chiefly made up of two components: hysteresis and eddy current losses. Hysteresis losses are caused by the magnetic lag or reluctance of the core molecules to reorient themselves with the 60 hertz alternating magnetic field applied by the primary winding. Eddy current losses are actual currents induced in the core by the magnetic field, in the same manner that the field induces current in the secondary winding. However, these currents cannot leave the core, and simply circulate within each lamination, eventually becoming heat. Both hysteresis and eddy currents create heat in the core material.

Measures to reduce core losses include utilizing thinner cold-rolled oriented laminated steel (e.g., M2 or M3) or amorphous material. However, these measures increase the manufacturing cost. In the case of amorphous material, due to a lower maximum core flux density, larges cores must be built, which increases the winding losses.

Winding losses occur in both the primary and secondary windings when a transformer is under load. These losses, the result of electrical resistance in both windings, vary with the square of the load applied to the transformer. As loading increases, winding losses increase and are typically much more significant than core losses at levels higher than 50 percent of the nameplate loading point.

Methods of reducing winding losses tend to cause an increase in no-load losses. One method is to increase the cross-sectional area of the conductor (decreasing current density in the winding material), but that means the core has to be made larger to accommodate the larger volume of the conductor, increasing core losses. Transposition of a multi-strand conductor can also help reduce winding losses.

Table 3.10.1 was prepared by ORNL.[i] This table summarizes the methods of making a transformer more efficient by reducing the number of watts lost in the core (no-load) and winding (load). However, as previously discussed, measures taken to reduce the losses in one area often increase the losses in another. This table presents those inter-relational issues, as well as the overall impacts on transformer manufacturing costs.

Table 3.10.1 Options and Impacts of Increasing Transformer Efficiency

	No-load losses	Load losses	Cost impact
To decrease no-load losses			
Use lower-loss core materials	Lower	No change*	Higher
Decrease flux density by:			
(a) Increasing core cross-sectional area (CSA)	Lower	Higher	Higher
(b) Decreasing volts per turn	Lower	Higher	Higher
Decrease flux path length by decreasing conductor CSA	Lower	Higher	Lower
Use 120˚ symmetry in three-phase cores**	Lower	No change	TBD
To decrease load losses			
Use lower-loss conductor material	No change	Lower	Higher
Decrease current density by increasing conductor CSA	Higher	Lower	Higher
Decrease current path length by:			
(a) Decreasing core CSA	Higher	Lower	Lower
(b) Increasing volts per turn	Higher	Lower	Lower

* Amorphous-core materials would result in higher load losses because flux density drops, requiring a larger core volume.

** Sometimes referred to as a "hexa-transformer" design.

The methods shown in Table 3.10.1 for making a transformer more efficient are discussed in the screening analysis (Chapter 4) and the engineering analysis (Chapter 5). DOE's analysis of the relationship between cost and efficiency for distribution transformers is presented in Chapter 5.

3.10.4 Core Deactivation

Core deactivation technology employs a system of smaller transformers to replace a single, larger transformer. For example, three transformers sized at 25 kVA and operated in parallel could replace a single 75 kVA transformer. The smaller transformers that compose the system can then be activated and deactivated using core deactivation technology based on the loading demand. Currently, DOE is not considering core deactivation systems in the context of setting standards, but may explore doing so in the future.

Winding losses are proportionally smaller at lower load factors, but for any given current, a smaller transformer will experience greater winding losses than a larger transformer. As a result, those losses may be more than offset by the smaller transformer's reduced core losses. As loading increases, winding losses become proportionally larger and eventually outweigh the power saved by using the smaller core. At that point, the control unit (which consumes little power itself) switches on an additional transformer, reducing winding losses at the cost of additional core losses. The control unit knows how efficient each combination of transformers is for any given loading, and is constantly monitoring the unit's power output so that it will use the optimal number of cores. In theory, there is no limit to the number of transformers that may be paralleled in this sort of system, but cost considerations would imply an optimal number.

While core deactivation could save energy over a real world loading cycle, those savings might not be represented in the current DOE test procedure. Presently, the test procedure specifies a single loading point of 50 percent for liquid-immersed and medium-voltage dry-type transformers, and 35 percent for low-voltage dry-type. The real gain in efficiency for this technology is at loading points below the root mean square (RMS) loading specified in the test procedure, where some transformers in the system could be deactivated. At loadings where all transformers are activated, which may be the case at the test procedure loading, the combined core and coil losses of the system of transformers could exceed those of a single, larger transformer. This would result in a lower efficiency for the system of transformers compared to the single, larger transformer.

Therefore, DOE believes core deactivation technology may be at a disadvantage in the market based on the current test procedure, which specifies a single loading based on the RMS loading in the United States. DOE believes that the core deactivation system would engage all transformers at this loading, resulting in a lower efficiency reading than a standard, single transformer of equivalent size. However, the core deactivation system may save more energy than the standard transformer when all loading points that are experienced in service are considered. This is especially true for applications that have an average loading below the test procedure loading point.

Based on comments received in response to the preliminary analysis, DOE has screened core deactivation out of its analysis. DOE acknowledges that it is possible to evaluate core deactivation technology using existing transformer designs, and that operating a core deactivation system might save energy and lower LCC. However, DOE does not believe that a bank of transformers used in a core deactivation system is a transformer itself but rather a system made up of individual transformers. DOE has adopted the position that each individual transformer in a core deactivation system must comply with the energy efficiency standards set in this rulemaking.

3.10.5 Symmetric Core

In a symmetric core configuration, each leg of a three-phase transformer is identically connected to the other two. It uses a continuously wound core with 120˚ radial symmetry, resulting in a triangularly shaped core when viewed from above. In a traditional core, the center leg is magnetically distinguishable from the other two because it has a shorter average flux path to each. In a symmetric core, however, no leg is magnetically distinguishable from the other two. Figure 3.10.3 shows the configuration of the symmetric core design.[2]

[2] Lundmark, Sonja. *Computer Model of Electromagnetic Phenomena in Hexaformer*. 2007. Available at: http://www.hexaformer.com/ExternaDokument/chalmers_report1.pdf.

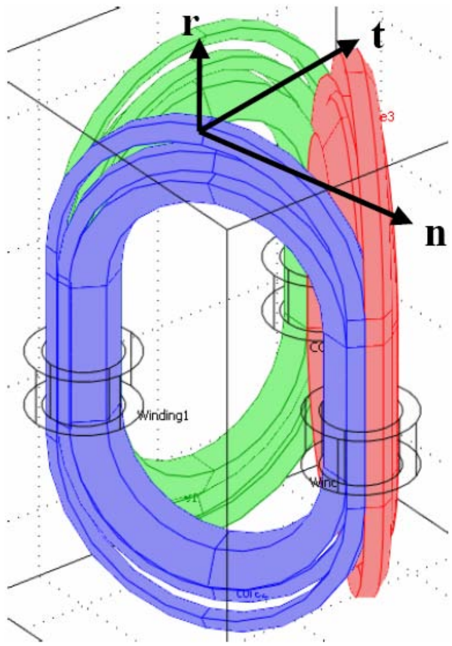

Figure 3.10.3 Graphic of Symmetric Core Configuration

The symmetric core construction offers several advantages over traditional transformer cores. These include lowered weight, volume, no-load losses, noise, vibration, stray magnetic fields, inrush current, and power in the third harmonic. Transformers using this core construction can oftentimes use fewer pounds of core steel than a standard core would use to achieve a given efficiency. As a result, total material cost for symmetric core designs is typically lower than that of a standard transformer design. However, the advanced manufacturing processes necessary to produce the core increases the cost of labor and overhead for this core configuration. Similarly, the appropriate equipment requires large capital expenditures to manufacture this core type.

Because of zero-sequence fluxes associated with wye-wye connected transformers, symmetric core designs are best suited to delta-delta or delta-wye connections. While traditional cores can circumvent the problem of zero-sequence fluxes by introducing a fourth or fifth unwound leg, core symmetry makes extra legs inherently impractical. Yet another way to mitigate zero-sequence fluxes comes in the form of a tertiary winding, which is delta-connected and has no external connections. This winding is dormant when the transformer's load is balanced across its phases. Although symmetric core designs may, in theory, be made tolerant of zero-sequence fluxes by employing this method, it comes at extra cost and complexity.

Using this tertiary winding, DOE believes that symmetric core designs can service nearly all distribution transformer applications in the United States. Most dry-type transformers have a delta connection and would not require a tertiary winding. Similarly, most liquid-immersed transformers serving the industrial sector have a delta connection. These market segments could use the symmetric core design without any modification for a tertiary winding. However, in the United States, most utility-operated distribution transformers are wye-wye connected. These transformers would require the tertiary winding in a symmetric core design.

Following the preliminary analysis, DOE did not receive any information regarding symmetric core and was unable to locate a company that had the modeling software to model symmetric core designs. The information DOE was able to collect was not sufficient enough to conduct a full-scale engineering analysis comparable to the other design types. Because the data was so limited and DOE did not receive any additional information from manufacturers, DOE did not consider symmetric core designs in this stage of the rulemaking.

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[iii] IEEE, 2001. IEEE PC57.12.33/D8 Draft Guide for Distribution Transformer Loss Evaluation, prepared by the Working Group for the Guide for Distribution Transformer Loss Evaluation of the Distribution Sub-committee of the IEEE Transformers Committee, October 2001.

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CHAPTER 4. SCREENING ANALYSIS

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CHAPTER 4. SCREENING ANALYSIS

4.1 INTRODUCTION

The purpose of the screening analysis is to identify design options that improve distribution transformer efficiency and to determine which options the U.S. Department of Energy (DOE) will evaluate and which options will be screened out. As discussed in the technology assessment portion of chapter 3, DOE consults with industry, technical experts, and other interested parties to develop a list of technology options for further consideration. It then applies the following set of screening criteria to determine which technology options are unsuitable for further consideration in the rulemaking (Title of the Code of Federal Regulations, Part 430 (10 CFR Part 430), subpart C, appendix A at 4(a)(4) and 5(b):

(1) Technological feasibility. Technologies incorporated in commercial products or in working prototypes will be considered 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 of the effective date of the standard, then that technology will be considered practicable to manufacture, install, and service.

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

(4) Adverse impacts on health or safety. If it is determined that a technology will have significant adverse impacts on health or safety, it will not be considered further.

This chapter discusses how DOE applied the four screening criteria to all of the technology options DOE considered in chapter 3. In the end, those technology options that are not screened out of the analysis become design options that DOE may consider for improving the energy efficiency of distribution transformers in the engineering analysis..

4.2 DISCUSSION OF TECHNOLOGY OPTIONS

There are several well-established engineering practices and techniques for improving the efficiency of a distribution transformer. A transformer design can be made more energy-efficient by improving the materials of construction (e.g., better quality core steel or winding material) and by modifying the geometric configuration of the core and winding assemblies.

Core and winding losses are not independent variables of transformer design; they are linked to each other by the heat they generate and by the physical space they occupy. Transformers are designed for a certain temperature rise, resulting from the heat generated by transformer losses during operation. The upper boundary on the temperature rise is a design constraint, based on industry practice and standards (Institute of Electrical and Electronics Engineers (IEEE) C57.12.00 and C57.12.01). If this temperature limitation is exceeded, it will accelerate the aging process of the insulation and reduce the operating life of the transformer.

In addition to the core and winding assemblies, a transformer has other non-electromagnetic elements that may constrain the design of a transformer: the electrical insulation, insulating media (oil for liquid-immersed transformers and air for dry-type transformers), and the enclosure (the tank or case). Once the insulation requirements are set, a transformer design can vary both materials and geometry to reduce the losses.

Making a transformer more efficient (i.e., reducing electrical losses) is a design tradeoff between more expensive, lower-loss materials, and the value a customer attaches to those losses. For a given efficiency level, the core and winding losses are generally inversely related—reducing one usually increases the other. Additionally, at a given loading point and associated efficiency level, there can be several viable designs that achieve that efficiency level. DOE found that a wide range of designs and efficiencies are technologically feasible using common materials, engineering practices, and construction techniques (see chapter 5).

Table 4.2.1 presents a general summary of the loss-reduction approaches from which transformer design engineers may choose to build more energy-efficient transformers. (This table was adapted from Table 2.2 in Oak Ridge National Laboratory (ORNL) report number 6847 published July 1996).[i] For most of these approaches, there are clear tradeoffs between no-load (core) losses, load (winding) losses, and price.

Some of the approaches presented in Table 4.2.1 refer to specific technologies (e.g., lower-loss core materials, lower-loss conductor materials), while other approaches refer to transformer geometry modifications (e.g., core or conductor cross-sectional area). This screening analysis considers the materials and technologies that may be used in transformer construction, but does not consider geometry or construction modifications such as a larger cross-sectional area, different core-stacking techniques, or symmetric cores. Construction methods and geometric modifications are inherent to the design and manufacturing process, and therefore are not a technology option considered in the screening analysis. These construction methods and geometric modifications are controlled by the transformer engineer and/or software design tool to improve the efficiency of resultant designs. Thus, they are applied to the designs prepared in the engineering analysis (see chapter 5).

Table 4.2.1 General Loss-Reduction Interventions for Distribution Transformers

Loss-Reduction Interventions		No-Load Losses	Load Losses	Effect on Price
Decrease Core Losses	Use lower-loss core materials	Lower	No Change*	Higher
	Decrease flux density by increasing core cross-sectional area	Lower	Higher	Higher
	Decrease flux density by decreasing volts/turn	Lower	Higher	Higher
	Decrease flux path length by decreasing conductor cross-sectional area	Lower	Higher	Lower
	Use 120˚ symmetry in three-phase cores**	Lower	No Change	TBD
Decrease Coil Losses	Use lower-loss conductor materials	No Change	Lower	Higher
	Decrease current density by increasing conductor cross-sectional area	Higher	Lower	Higher
	Decrease current path length by decreasing core cross-sectional area	Higher	Lower	Lower
	Decrease current path length by increasing volts/turn	Higher	Lower	Lower

* Amorphous-core materials would result in higher load losses because flux density drops, requiring a larger core volume.

** Sometimes referred to as a "hexa-transformer" design.

4.3 TECHNOLOGY OPTIONS NOT SCREENED OUT OF THE ANALYSIS

DOE considers all distribution transformer technology options currently in use by distribution transformer manufacturers to be viable. Viable design options include different conductor materials for coils and core materials.

4.3.1 Conductor Materials

Aluminum and copper are used in current distribution transformer designs and are available for use in standard wire sizes and foils. When the two materials are applied in exactly the same manner, copper has a higher electrical conductivity and about 40 percent lower resistive losses than aluminum. Compared to copper, aluminum is easier to form and work mechanically, and can be less expensive. By utilizing aluminum conductor material at a lower current density (i.e., larger conductor cross-sectional area), aluminum transformer windings can be built with essentially the same load losses as copper. However, aluminum conductors increase core losses due to their larger core frames, necessitated by the larger winding space ("core window") through which the windings must pass. It is common for an efficient design option to have copper in the high-voltage (HV) windings and aluminum at a lower current density in the low-voltage (LV) windings. In these LV windings, aluminum can be used in the form of flat, rolled foils to reduce eddy current losses.

Considering the four screening criteria for this technology, DOE did not screen out aluminum and copper as conductor materials. These materials are in commercial use today, and DOE therefore found them to be technologically feasible. They are obviously practicable to manufacture, install, and service because they have been used in mass production for many years and are expected to continue to be the primary winding materials for the foreseeable future. There are no adverse impacts on consumer utility or reliability associated with the use of these conductor materials. Finally, there are no additional adverse impacts on health or safety associated with the use of these winding materials.

4.3.2 Core Materials

Transformer cores in the past had relatively high losses, since they were fabricated from thick laminates of non-oriented, low-silicon, magnetic steels. Modern cores are made with steels that incorporate silicon (approximately 2–3 percent) and trace amounts of other elements, are cold-rolled to thinner laminations, have improved laminar insulation, and may also be grain-oriented or domain-refined (i.e., laser or mechanically scribed steels).

Amorphous metal material allows the construction of a low-loss core. Amorphous metal is extremely thin, has high electrical resistivity, and has little or no magnetic domain definition. Cores made from this material can exhibit 60–70 percent lower core losses than one made of conventional steels. However, amorphous metal material does have some drawbacks: it saturates at a lower flux level of 1.57 Tesla versus 2.08 Tesla for conventional materials, and it has higher excitation requirements. Amorphous metal material is also fragile and requires special handling during the construction process. Additionally, these designs cannot be "packed" as effectively into the winding window, causing the designs to have a space factor of 85 percent versus 95–98 percent for steel core materials, which increases losses. The net effect of the lower flux density and higher space factor is a larger core with greater winding (conductor) losses and higher production costs.

The core steels considered in this screening analysis are all those found in commercial use today. These include high-silicon electrical steels, both non-oriented hot-rolled and grain-oriented cold-rolled, domain-refined grain-oriented electrical steel, and amorphous material (wound-core designs). DOE considered all of these core materials to be technologically feasible, as they are used commercially today (or in the past) by distribution transformer manufacturers at varying flux levels and lamination thicknesses. These commercially available high-silicon, cold-rolled transformer steels, nominally designated M2-M6, and domain-refined or laser-scribed steels are available for use in both stacked- and wound-core configurations. However, at present the application of amorphous material is only a viable design option in a wound core. No manufacturers currently produce an amorphous product that can be used in a stacked-core configuration (discussed in section 4.4.3 of this chapter).

These core steels, high-silicon electrical steels, both non-oriented hot-rolled and grain-oriented cold-rolled, domain-refined grain-oriented, and amorphous material (wound core designs), are considered practicable to manufacture, install, and service, since they are core materials that are being used or that have been used by the distribution transformer industry. There are no known adverse impacts on consumer utility or reliability, and no known adverse impacts on health or safety associated with these core materials.

Table 4.3.1 summarizes the design options not screened out of the analysis.

Table 4.3.1 Design Options Not Screened Out of the Analysis

Design Issue	Material
Conductor Materials for Coils	Aluminum (wire and sheet)
	Copper (wire and sheet)
Core Materials	Cold-Rolled High Silicon (CRHiSi) Steel
	CRHiSi Domain-Refined Steels
	Amorphous Materials in Wound Core
Core Deactivation Technology	(Not applicable)

4.4 TECHNOLOGY OPTIONS SCREENED OUT OF THE ANALYSIS

DOE screened out the following design options from further consideration because they do not meet the screening criteria:

1. Silver as a conductor material
2. High-temperature superconductors
3. Amorphous core material in stacked core configuration
4. Carbon composite materials for heat removal
5. High-temperature insulating material
6. Solid-state (power electronics) technology
7. Nanotechnology Composites

4.4.1 Silver as a Conductor Material

The electrical conductivity of silver exceeds that of copper, aluminum, and other normal metals at room temperature (25˚ Celsius). However, silver has a lower melting point, a lower tensile strength, and limited availability. DOE found that the use of silver as a conductor is technologically feasible, since distribution transformers with silver windings were built during World War II because of a war-time shortage of copper. DOE believes the use of silver as a conductor would not have any adverse impacts on consumer utility or reliability, as it can readily replace copper or aluminum in this application. DOE is also not aware of any adverse health or safety impacts associated with the use of this conductor material.

However, DOE screened out silver as a conductor material because it is impracticable to manufacture, install, and service. Silver conductor designs are constrained by lower operating temperatures (adding to manufacturing complexity) and lower tensile strength (material can easily break during manufacturing process). In addition, due to limited availability, silver is not feasible to use for mass production on the scale necessary to serve the U.S. distribution transformer manufacturing industry.

Thus, DOE screened silver out from further consideration as a conductor material in the analysis due to its impracticability to manufacture, install, and service (criterion 2).

4.4.2 High-Temperature Superconductors

A new class of high-temperature superconducting (HTS) materials was discovered in 1987. These new materials become superconducting at temperatures close to that of liquid nitrogen, a readily available coolant that is considerably less expensive than liquid helium, the coolant for the previous generation of superconducting materials. After the discovery of these materials, research programs were launched worldwide to explore the use of superconducting material in power transformers. However, the use of superconductors, both low- and high-temperature, in transformer manufacturing has proven to be an elusive goal. Low-temperature superconductors (liquid helium-cooled) are physically possible but not feasible for commercial use, since these units are often unable to return to the superconducting state following a high fault current condition. For HTS (liquid nitrogen-cooled), a few demonstration power transformers have been built, but a prototype distribution transformer has not been constructed. Design constraints include unique conductors, unacceptable alternating current variation losses, and complex cryogenic support components. Research to overcome these barriers is being conducted, some of which is funded by DOE.

HTS materials were screened out of further consideration in this analysis because they fail on two of the four screening criteria. First, DOE does not consider HTS materials to be technologically feasible because a HTS distribution transformer has never been built. Additionally, due to technical issues associated with HTS power transformers, DOE does not consider HTS technology a viable loss-reduction technology for distribution transformers now or in the foreseeable future. Second, DOE does not consider HTS materials to be practicable to manufacture because they are extremely brittle (built of ceramic composites), are orders of magnitude more expensive than conventional conductor material, and are not mass-produced in a manner that would meet the demands of today's distribution transformer market. Furthermore, they are not reliable in service because they require continuous active cooling or they cease to function. With regard to the third screening criterion, DOE is not aware of any adverse impacts on customer utility associated with these materials. Similarly, DOE is not aware of any adverse impacts on health and safety originating from the use of HTS materials.

Thus, DOE screened HTS materials out of the analysis because of technological infeasibility (criterion 1) and impracticability to manufacture, install, and service (criterion 2).

4.4.3 Amorphous Core Material in Stacked Core Configuration

As discussed in section 4.3.2, amorphous material is considered a viable core material in a wound-core configuration. However, stacked amorphous core material is not presently a viable design option for distribution transformers, and is not currently used by any manufacturers.

DOE screened out stacked core amorphous core material from further consideration in the analysis. First, DOE is not aware of any working prototypes that use amorphous core material in a purely stacked core configuration. Thus, the technological feasibility of this material has not been demonstrated. DOE is aware of at least one manufacturer that utilized a variation of an amorphous core in a stacked core configuration. This patented design process involved joining multiple amorphous strips together. The process was not economically feasible in the United States, and is not currently used by any U.S. manufacturers.

Second, the material has not demonstrated its practicability with respect to manufacturing, and therefore cannot be assessed as to its ability to meet the demand of mass production nor demonstrate its reliability in service. Considering the third criterion, DOE is not aware of any adverse impacts on utility or availability to consumers associated with this material. Similarly, for the fourth criterion, DOE is not aware of any adverse impacts on health and safety from the use of amorphous core material in stacked core configuration.

Thus, DOE screened amorphous core materials in stacked core configuration out of the analysis due to technological infeasibility (criterion 1) and impracticability to manufacture, install, and service (criterion 2).

4.4.4 Carbon Composite Materials for Heat Removal

A new technology that may prove effective in future transformer designs is the use of carbon fiber composites for heat removal. These materials offer good heat conduction and electrical insulation performance. The U.S. Naval Research Laboratory built small (less than 1 kVA), high-frequency transformers with this technology and demonstrated a 35 percent size and core loss reduction. While these results are impressive, a larger-scale prototype distribution transformer has not been demonstrated, and if it were technologically feasible, it would still be several years away from commercialization.

DOE assessed carbon composite materials for heat removal from distribution transformers, and found the material failed the first screening criterion. These materials for heat removal failed the first screening criterion because there are no commercial products or working prototypes that incorporate this technology. DOE was not able to assess whether the material meets or fails any of the other three screening criteria. Specifically, DOE cannot determine whether transformers would be practicable to manufacture, install, and service with this new material, since the application of the technology in a distribution transformer design has not been determined. Similarly, any potential adverse impacts on consumer utility or availability cannot be assessed, and any adverse impacts on health and safety cannot be determined at this time.

Thus, DOE screened carbon composite materials for heat removal out of the analysis due to technological infeasibility (criterion 1).

4.4.5 High-Temperature Insulating Material

The transformer industry conducts research and development on insulating materials. While potentially improving dielectric performance, industry studies this technology to create an electrical insulation that can withstand higher operating temperatures, and to create an electrical insulation that conducts heat more effectively out of the core-coil assembly. Increasing electrical insulation performance would result in smaller effective core and coil volumes, and therefore reduce operating losses.

DOE assessed high-temperature insulating materials, and found that the material failed on the first screening criterion. DOE is not aware of any practical high-temperature insulating or composite heat removal material, either in prototype form or in commercial products. DOE was not able to assess whether the material meets or fails any of the other three screening criteria. Transformers are built today with standard grades of insulation (up to 220˚ Celsius); however, it is uncertain whether higher temperature materials may have certain issues that make them impracticable to manufacture, install, or service. Similarly, DOE is unable to assess whether there would be any adverse impacts on consumer utility or availability due to the lack of a working prototype. Finally, DOE is unable to assess whether there would be any adverse impacts on health and safety aspects of a distribution transformer because of this material.

Thus, DOE screened high-temperature insulating materials out of the analysis due to technological infeasibility (criterion 1).

4.4.6 Solid-State (Power Electronics) Technology

The application of solid-state (power electronics) technology to transformers is in the early stages of research. DOE is aware that small test transformers have been built for research to assess the technology, but no commercial distribution transformer product offering has ever been manufactured using this technology. This is largely due to the fact that the designs have been prohibitively expensive and less-efficient than a standard transformer design.

Solid-state technology has not achieved the same efficiency levels as standard transformer designs, and the designs come at a high cost. The electronic transformer functionally consists of a high frequency chopper typically operating at 20 kilohertz (kHz), a high frequency step-down transformer at the chopping frequency, and a power frequency modulator at the 60 Hz frequency with a large commutating capacitor. Fundamentally, there must be a minimum of two sets of power electronic devices, one at the source side (high voltage primary) and one at the load side (low voltage secondary). The forward voltage drop in each power switching device is a minimum of 1.0 volt. The significant currents passing through each device result in very high losses. Hence, even before the inefficiencies of the high frequency magnetic components are considered, the power electronic devices consume more power than the total losses of conventional transformers. High-frequency magnetic losses are not much lower than low-frequency magnetic losses. This makes the total loss higher than what can be achieved with conventional, low-frequency magnetics.

Additionally, it would not be practicable to manufacture transformers using this technology on the scale necessary to serve the distribution transformer market. A manufacturer wishing to use the technology would need an entirely new manufacturing facility to handle this unique design. The manufacturer would need electronic circuit cards for the signal electronics, wave soldering, aluminum heat sinks, power electronic semiconductors, sintered cores, and unique winding equipment. Ferrite magnetic core materials are also required instead of silicon iron sheeted cores.

DOE assessed the feasibility of solid-state (power electronics) technology, and found that this technology failed on the first and second screening criteria. DOE is not aware of any solid-state distribution transformers that can achieve improvements in efficiency, either in prototype form or in a commercial product. DOE also does not believe the technology would be practicable to manufacture on the scale necessary to serve the distribution transformer market. DOE was not able to assess whether solid-state transformer technology meets or fails any of the remaining screening criteria. DOE is unable to assess whether there would be any adverse impacts on consumer utility or availability associated with this technology. Finally, DOE is unable to assess whether there would be any adverse impacts on health and safety aspects of a distribution transformer.

Thus, DOE screened solid-state power electronics transformer technology out of the analysis due to technological infeasibility and practicability to manufacture, install, and service (criteria 1 and 2).

4.4.7 Nanotechnology Composites

DOE understands that the nanotechnology field is actively researching ways to produce bulk material with desirable properties on the molecular scale. Some of these materials may have high resistivity, high permeability, or other properties that make them attractive for use in electrical transformers. DOE knows of no current commercial efforts to employ these materials in distribution transformers and no prototype designs using this technology.

DOE assessed the feasibility of nanotechnology composites, and found that this technology failed on the first screening criterion. DOE is not aware of any distribution transformer using nanotechnology composites, either in prototype form or in a commercial product. DOE was not able to assess whether nanotechnology composite transformers meet or fail any of the remaining screening criteria. Due to the lack of a working prototype, DOE is uncertain whether this technology may have certain issues that make it impracticable to manufacture, install or service. Similarly, DOE is unable to assess whether there would be any adverse impacts on consumer utility or availability associated with this technology. Finally, DOE is unable to assess whether there would be any adverse impacts on health and safety aspects of a distribution transformer.

Thus, DOE screened nanotechnology composites out of the analysis due to technological infeasibility (criterion 1).

4.5 SUMMARY OF TECHNOLOGY OPTIONS SCREENED OUT

Those design options that DOE screened out from further consideration are listed below in Table 4.5.1. The design options that DOE did not screen out of the analysis are listed in Table 4.3.1.

Table 4.5.1 Design Options Screened Out of the Analysis

Design Option Excluded	Screening Criteria
Silver as a Conductor Material	Practicability to manufacture, install, and service
High-Temperature Superconductors	Technological feasibility; Practicability to manufacture, install, and service
Amorphous Core Material in Stacked Core Configuration	Technological feasibility; Practicability to manufacture, install, and service
Carbon Composite Materials for Heat Removal	Technological feasibility
High-Temperature Insulating Material	Technological feasibility
Solid-State (Power Electronics) Technology	Technological feasibility; Practicability to manufacture, install, and service
Nanotechnology Composites	Technological feasibility

REFERENCES

[i] ORNL, 1996. Oak Ridge National Laboratory, Determination Analysis of Energy Conservation Standards for Distribution Transformers, P.R. Barnes, J.W. Van Dyke, B.W. McConnell, S. Das, ORNL report number 6847, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Published July 1996. Available online at: www.eere.energy.gov/buildings/appliance_standards/ commercial/dist_transformers.html

CHAPTER 5. ENGINEERING ANALYSIS

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CHAPTER 5. ENGINEERING ANALYSIS

5.1 INTRODUCTION

This chapter provides the technical support documentation for the engineering analysis, evaluating both liquid-immersed and dry-type distribution transformers. The purpose of the engineering analysis is to estimate the relationship between the manufacturer's selling price (MSP) of a transformer and its corresponding efficiency rating. This relationship serves as the basis for the subsequent cost-benefit calculations for individual customers, manufacturers, and the nation (see chapter 8, Life-Cycle Cost and Payback Period Analyses).

5.2 STRUCTURING THE ENGINEERING ANALYSIS

As discussed in the market and technology assessment (chapter 3), distribution transformers are classified by their insulation type (liquid-immersed or dry-type), the number of phases (single or three), the primary voltage (low-voltage or medium-voltage for dry-types) and the basic impulse insulation level (BIL) rating (for dry-types). Following this convention, the U.S. Department of Energy (DOE) developed ten equipment classes, shown in Table 5.1. These equipment classes were adapted from the National Electrical Manufacturers Association (NEMA)'s TP 1 classification system, although they do not follow the classification system precisely. NEMA's TP 1 classifies medium-voltage, dry-type distribution transformers into two equipment classes, ≤ 60 kilovolt (kV) BIL and > 60 kV BIL. Based on input from manufacturers, DOE elected to increase the differentiation of medium-voltage, dry-type transformers, and create three equipment classes of BIL ratings: 20–45 kV BIL, 46–95 kV BIL, and ≥ 96kV BIL (see chapter 3, section 3.3).

Within each of these equipment classes, DOE further classified distribution transformers by their kilovolt-ampere (kVA) rating. These kVA ratings are size categories, indicating the power handling capacity of the transformers. Due to differences in construction methods and material properties, efficiency levels vary by both equipment class and kVA rating. For NEMA's TP 1-2002,[1] there are 99 kVA ratings across all the equipment classes. For DOE's rulemaking, because of the greater degree of differentiation around the BIL rating in medium-voltage, dry-type transformers, there are 115 kVA ratings across all the equipment classes, as shown in Table 5.1.

[1] NEMA's TP 1-2002 can be found online at: http://www.nema.org/stds/tp1.cfm#download.

Table 5.1 Equipment Classes and Number of kVA Ratings

Distribution Transformer Equipment Class	kVA Range	Number of kVA Ratings
1. Liquid-immersed, medium-voltage, single-phase	10–833	13
2. Liquid-immersed, medium-voltage, three-phase	15–2500	14
3. Dry-type, low-voltage, single-phase	15–333	9
4. Dry-type, low-voltage, three-phase	15–1000	11
5. Dry-type, medium-voltage, single-phase, 20-45 kV BIL	15–833	12
6. Dry-type, medium-voltage, three-phase, 20-45 kV BIL	15–2500	14
7. Dry-type, medium-voltage, single-phase, 46-95 kV BIL	15–833	12
8. Dry-type, medium-voltage, three-phase, 46-95 kV BIL	15–2500	14
9. Dry-type, medium-voltage, single-phase, $\geq$ 96 kV BIL	75–833	8
10. Dry-type, medium-voltage, three-phase, $\geq$ 96 kV BIL	225–2500	8
	Total	115

DOE recognized that it would be impractical to conduct a detailed engineering analysis on all 115 kVA ratings, so it sought to develop an approach that simplified the analysis while retaining reasonable levels of accuracy. DOE consulted with industry representatives and transformer design engineers and developed an understanding of the construction principles for distribution transformers. It found that many of the units share similar designs and construction methods. Thus, DOE simplified the analysis by creating 14 engineering design lines, which group kVA ratings based on similar principles of design and construction. The 14 design lines subdivide the equipment classes, to improve the accuracy of the engineering analysis. These 14 engineering design lines differentiate the transformers by insulation type (liquid-immersed or dry-type), number of phases (single or three), and primary insulation levels for medium-voltage, dry-type (three different BIL ratings).

DOE then selected one unit from each of the engineering design lines for study in the engineering analysis and the life-cycle cost (LCC) analysis (see chapter 8), reducing the number of units for analysis from 115 to 14. It then extrapolated the results of its analysis from the unit studied to the other kVA ratings within that same engineering design line. DOE performed this extrapolation in the national impacts analysis (see chapter 10). DOE used kVA scaling to extrapolate findings from a representative unit to the other kVA ratings within its design line. . An example of how DOE applied this scaling appears in section 5.2.1 of this chapter. A technical discussion of the derivation of kVA scaling appears in appendix 5B.

Table 5.2 presents DOE’s 14 design lines and the representative units selected from each engineering design line for analysis. Descriptions of each of the design lines and the rationale behind the selection of the representative units follow Table 5.2.

Table 5.2 Engineering Design Lines (DLs) and Representative Units for Analysis

EC*	DL	Type of Distribution Transformer	kVA Range	Representative Unit for this Engineering Design Line
1	1	Liquid-immersed, single-phase, rectangular tank	10–167	50 kVA, 65°C, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank, 95kV BIL
	2	Liquid-immersed, single-phase, round tank	10–167	25 kVA, 65°C, single-phase, 60Hz, 14400V primary, 120/240V secondary, round tank, 125 kV BIL
	3	Liquid-immersed, single-phase	250–833	500 kVA, 65°C, single-phase, 60Hz, 14400V primary, 277V secondary, 150kV BIL
2	4	Liquid-immersed, three-phase	15–500	150 kVA, 65°C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary, 95kV BIL
	5	Liquid-immersed, three-phase	750–2500	1500 kVA, 65°C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary, 125 kV BIL
3	6	Dry-type, low-voltage, single-phase	15–333	25 kVA, 150°C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL
4	7	Dry-type, low-voltage, three-phase	15–150	75 kVA, 150°C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL
	8	Dry-type, low-voltage, three-phase	225–1000	300 kVA, 150°C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL
6	9	Dry-type, medium-voltage, three-phase, 20-45kV BIL	15–500	300 kVA, 150°C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL
	10	Dry-type, medium-voltage, three-phase, 20-45kV BIL	750–2500	1500 kVA, 150°C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
8	11	Dry-type, medium-voltage, three-phase, 46-95kV BIL	15–500	300 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
	12	Dry-type, medium-voltage, three-phase, 46-95kV BIL	750–2500	1500 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
10	13A	Dry-type, medium-voltage, three-phase, 96-150kV BIL	75–833	300 kVA, 150°C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL
	13B	Dry-type, medium-voltage, three-phase, 96-150kV BIL	225–2500	2000 kVA, 150°C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL

* EC means equipment class (see chapter 3 of the TSD). DOE did not select any representative units from the single-phase, medium-voltage equipment classes (EC5, EC7 and EC9), but calculated the analytical results for EC5, EC7, and EC9 based on the results for their three-phase counterparts.

DOE divided liquid-immersed transformers into five engineering design lines, based on their tank shape, number of phases, and kVA ratings. DOE believes that this breakdown enables the analysis to identify and capture a more accurate representation of the manufacturer's selling price and efficiency relationship. DOE broke dry-type distribution transformers into eight engineering design lines, primarily according to their BIL ratings. DOE believes this level of disaggregation is necessary to capture important differences in the price-efficiency relationship, particularly as the BIL rating varies. For example, a 300 kVA, three-phase, dry-type unit could be classified in design lines 8, 9, or 11, or 13A, depending on whether the BIL rating is 10 kV (low-voltage), 20-45 kV, 46-95 kV, or 96-150 kV.

For design lines 9 through 13B, the representative units selected for some of the dry-type design lines may not be the standard BILs associated with a given primary voltage. DOE selected a slightly higher BIL for the representative units from these design lines to ensure that any minimum efficiency standard would not excessively penalize customers purchasing transformers at higher BIL ratings within the range. For example, a 300 kVA transformer with a 4160V primary is called a “5kV class” transformer and would normally be built with a 30kV BIL. However, customers may also choose to order this transformer with 45kV BIL or 60kV BIL. If the minimum efficiency level were set based on a 30kV BIL, it may not be possible to achieve that same efficiency rating for customers ordering 60kV BIL. Thus, DOE evaluated the middle BIL rating (in this example, 45kV BIL), making it slightly easier to comply for a lower BIL, and not too difficult (or impossible) for the higher BIL.

The remainder of this section discusses each of the 14 engineering design lines, providing a description and explanation of the transformers covered.

Design Line 1. This is the basic, high-volume line for rectangular-tank, single-phase, liquid-immersed distribution transformers, ranging from 10 kVA to 167 kVA. Transformers in this design line typically have BILs ranging from 30 kV to 150 kV (this unit is 95 kV) and a tap configuration of four 2½ percent taps—two above and two below the nominal voltage. Tap configurations enable transformer users to maintain full (rated) output voltage by slightly increasing or decreasing the number of turns in the primary in anticipation of an input voltage slightly above or below the rated nominal. This design line has a primary voltage less than 35 kV, and a secondary voltage less than or equal to 600 Volts (V).

The representative unit selected for design line 1 is a 50 kVA pad-mounted unit, as this is a high shipment volume rating, and is approximately the middle of the kVA range for this design line (10 kVA, 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, and 167 kVA). Engineering design considerations and manufacturing differences led to the placement of 250 kVA and higher-rated units in design line 3.

Design Line 2. This is the basic, high-volume line for round-tank (pole-mounted), single-phase, liquid-immersed distribution transformers, ranging from 10 kVA to 167 kVA. Although some manufacturers tend to employ the same basic core/coil design for design line 1 and design line 2, others may have design differences between pad-mounted and pole-mounted transformers. DOE decided to analyze these two types of distribution transformers separately for the engineering and LCC analyses. Transformers in design line 2 typically have BILs ranging from 30 kV to 150 kV (this unit is 125 kV), a tap configuration of four 2½ percent taps—two above and two below the nominal, a primary voltage less than 35 kV, and a secondary voltage less than or equal to 600 V.

The representative unit selected for design line 2 is a 25 kVA pole-mounted unit, as this is a high-volume rating for pole-mounted transformers, and is on the lower end of the kVA range for this design line (10 kVA, 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, and 167 kVA). . Engineering design considerations and manufacturing differences led to the placement of 250 kVA and higher-rated units in design line 3.

Design Line 3. This design line groups together single-phase, round-tank, liquid-immersed distribution transformers, ranging from 250 kVA to 833 kVA. Together, design lines 1 through 3 cover all the single-phase, liquid-immersed units (there are no standard kVA ratings between 167 and 250 kVA). Transformers in this design line typically have BILs ranging from 30 kV to 150 kV (this unit is 150 kV), a tap configuration of four 2½ percent taps—two above and two below the nominal, a primary voltage less than 35 kV, and a secondary voltage less than or equal to 600 V.

The representative unit selected for design line 3 is a 500 kVA round-tank, as this rating occurs in the middle of the kVA range for this design line (250 kVA, 333 kVA, 500 kVA, 667 kVA, and 833 kVA). Although high currents result from having a 277 V secondary at the larger kVA ratings, high current bushings are available, and a market does exist for these transformers.

Design Line 4. Design line 4 represents rectangular tank, three-phase, liquid-immersed distribution transformers, ranging from 15 kVA to 500 kVA. Transformers in this design line typically have BILs ranging from 30 kV to 150 kV (this unit is 95 kV), a tap configuration of four 2½ percent taps—two above and two below the nominal, a primary voltage less than 35 kV, and a secondary voltage less than or equal to 600 V.

The representative unit selected for design line 4 is a 150 kVA transformer, as this is a common rating in this design line and occurs approximately in the middle of the kVA range (15 kVA, 30 kVA, 45 kVA, 75 kVA, 112.5 kVA, 150 kVA, 225 kVA, 300 kVA, and 500 kVA).

Design Line 5. Design line 5 represents rectangular tank, three-phase, liquid-immersed distribution transformers, ranging from 750 kVA to 2500 kVA. Together, design lines 4 and 5 cover all the three-phase, liquid-immersed units (there are no standard kVA ratings between 500 and 750 kVA). Transformers in this design line typically have BILs ranging from 95 kV to 150 kV (this unit is 125 kV), a tap configuration of four 2½ percent taps—two above and two below the nominal, a primary voltage less than 35 kV, and a secondary voltage less than or equal to 600 V.

The representative unit selected for this design line is a 1500 kVA transformer, as this is a common rating in this size range, and occurs in the middle of the kVA range for this design line (750 kVA, 1000 kVA, 1500 kVA, 2000 kVA, and 2500 kVA).

Design Line 6. Design line 6 represents single-phase, low-voltage, ventilated dry-type distribution transformers, ranging from 15 kVA to 333 kVA. Transformers in this design line typically have BIL ratings of 10 kV and a “universal” tap arrangement, meaning six 2½ percent taps, two above and four below the nominal. DOE selected this tap arrangement based on recommendations from manufacturers who produce transformers at these ratings. The primary and secondary voltages are both 600 V or below.

The representative unit selected for design line 6 is a 25 kVA transformer, as this is a common rating in this size range, and occurs toward the low end of the kVA ratings for this design line (15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, 167 kVA, 250 kVA, and 333 kVA).

Design Line 7. Design line 7 represents three-phase, low-voltage, ventilated dry-type distribution transformers, ranging from 15 kVA to 150 kVA. Because the kVA range of three-phase ratings is broad and construction techniques differ, DOE split the range of three-phase, low-voltage, dry-type transformers into design line 7 and design line 8, so the engineering differences in core-coil design and manufacturing would be more readily apparent. Transformers in this design line typically have BIL ratings of 10 kV and a "universal" tap arrangement, meaning six 2½ percent taps, two above and four below the nominal. The primary and secondary voltages are both 600 V or below.

The representative unit selected for design line 7 is a 75 kVA transformer, as this is a common rating in this size range, and occurs in the middle of the kVA ratings for this design line (15 kVA, 30 kVA, 45 kVA, 75 kVA, 112.5 kVA, and 150 kVA).

Design Line 8. Design line 8 represents three-phase, low-voltage, ventilated dry-type distribution transformers, ranging from 225 kVA to 1000 kVA. Transformers in this design line typically have BIL ratings of 10 kV and a tap arrangement of four 2½ percent taps, two above and two below the nominal. The primary and secondary voltages are both 600 V or below.

The representative unit selected for design line 8 is a 300 kVA transformer, as this is a common rating in this size range, and occurs toward the lower end of the range of kVA ratings included in this design line (225 kVA, 300 kVA, 500 kVA, 750 kVA, and 1000 kVA).

Design Line 9. Design line 9 represents three-phase, medium-voltage, ventilated dry-type distribution transformers, ranging from 15 kVA to 500 kVA. To accommodate the broad kVA range and to allow for engineering differences in construction principles and associated costs, DOE split the three-phase, medium-voltage, dry-type units into design lines 9 and 10. Transformers in design line 9 typically have primary voltages less than or equal to 5 kV with a BIL rating between 20 kV and 45 kV. The secondary voltage is less than or equal to 600 V and the tap arrangement is typically four 2½ percent taps, two above and two below the nominal.

The representative unit selected for design line 9 is 300 kVA, as this is a common rating in this size range, and occurs near the high end of the kVA ratings for this design line (15 kVA, 30 kVA, 45 kVA, 75 kVA, 112.5 kVA, 150 kVA, 225 kVA, 300 kVA, and 500 kVA).

Design Line 10. Design line 10 represents three-phase, medium-voltage, ventilated dry-type distribution transformers, ranging from 750 kVA to 2500 kVA. Transformers in this design line typically have primary voltages less than or equal to 5 kV with a BIL rating between 20 kV and 45 kV. The secondary voltage is less than or equal to 600 V and the tap arrangement is typically four 2½ percent taps, two above and two below the nominal.

The representative unit selected for this design line is a 1500 kVA transformer, as this is a common rating, and occurs in the middle of the kVA range for this design line (750 kVA, 1000 kVA, 1500 kVA, 2000 kVA, and 2500 kVA).

Design Line 11. Design line 11 represents three-phase, medium-voltage, ventilated dry-type distribution transformers, ranging from 15 kVA to 500 kVA. This design line parallels design line 9, with a higher primary insulation level, 46 kV to 95 kV BIL. Because dry-type transformer designs and, more importantly, the efficiency of those designs, are strongly influenced by changes in BIL, DOE considered these higher BIL ratings separately. The typical tap arrangement is four 2½ percent taps, two above and two below the nominal. The primary voltage is typically less than or equal to 15 kV and the secondary voltage is less than or equal to 600 V.

The kVA ratings in design line 11 are 15 kVA, 30 kVA, 45 kVA, 75 kVA, 112.5 kVA, 150 kVA, 225 kVA, 300 kVA, and 500 kVA. The shipments for this design line are primarily in the kVA range inclusive of and between 225 kVA and 500 kVA; therefore, DOE selected the 300 kVA rating as the representative unit for analysis.

Design Line 12. Design line 12 represents three-phase, medium-voltage, ventilated dry-type distribution transformers, ranging from 750 kVA to 2500 kVA. This design line parallels design line 10, with a higher primary insulation level, 46 kV to 95 kV BIL. The typical tap arrangement is four 2½ percent taps, two above and two below the nominal. The primary voltage is typically less than or equal to 15 kV and the secondary voltage is less than or equal to 600 V.

The representative unit selected for this design line is a 1500 kVA transformer, as it is a common rating in this size range and BIL rating, and it occurs in the middle of the kVA range covered by this design line (750 kVA, 1000 kVA, 1500 kVA, 2000 kVA, and 2500 kVA).

Design Lines 13A and 13B. As a further extension on the dry-type, three-phase, medium-voltage BIL ranges, DOE originally analyzed 96 kV to 150 kV BIL in a single design line ranging from 225 kVA to 2500 kVA. The 225 kVA rating is considered to be the lowest kVA rating where one would expect to see a unit with a BIL greater than 110 kV. The typical tap arrangement is four 2½ percent taps, two above and two below the nominal. The primary voltage is typically less than or equal to 35 kV and the secondary voltage is less than or equal to 600 V.

This third set of dry-type, three-phase, medium-voltage distribution transformers spans a wide range of kVA ratings. (225 kVA, 300 kVA, 500 kVA, 750 kVA, 1000 kVA, 1500 kVA, 2000 kVA, and 2500 kVA). Based on comments received after the preliminary analysis, DOE decided to split the former design line 13 into two design lines, 13A and 13B, in order to improve scaling accuracy within EC10. The representative unit selected for design line 13A is a 300 kVA transformer. This unit is a common rating in this size range, and occurs toward the low end of the range covered by this design line. The representative unit selected for design line 13 B is a 2000 kVA transformer, which occurs toward the high end of the range covered by this design line.

In addition to the three equipment classes for dry-type, medium-voltage, three-phase distribution transformers (for which there are five engineering design lines) presented in Table 5.1, there are three equipment classes for single-phase, dry-type, medium-voltage units. As discussed in chapter 3, the shipment volume for single-phase, dry-type, medium-voltage transformers is very low as a percentage of the total dry-type shipments. Additionally, the total megavolt-ampere (MVA) capacity of single-phase, dry-type, medium voltage transformers is relatively low as a percentage of the total MVA capacity for dry-type, medium voltage transformers. Therefore, it does not warrant the level of effort involved in conducting analysis on these specific units. DOE decided instead to scale the analysis findings from three-phase units to the single-phase units. During the negotiations, DOE worked with various manufacturers and committee members to develop a new approach. . In the end, DOE decided to scale the losses from each three-phase transformer to calculate losses and efficiency for the equivalently sized single-phase transformer. . Additional details and rationale appear in section 5.2.2.. In this way, DOE was able to concentrate resources and improve the accuracy in other, higher volume and more important distribution transformer equipment classes.

5.2.1 Summary of Design Line Coverage

The following four tables summarize the coverage of each of the design lines in relation to the various equipment classes and kVA ratings. The abbreviation DL stands for design line, and the row in the table where the phrase “Rep Unit” appears indicates the kVA rating of the representative unit from that design line. The representative unit is the kVA rating that DOE analyzed in the engineering and LCC analyses. For example, DL1 stands for design line 1, spanning from 10 to 167 kVA liquid-type, single-phase. The label “Rep Unit” appears in row 50 kVA, indicating that the 50 kVA is the representative unit for DL1. Similarly, the representative unit for DL2 is the 25 kVA unit.

There are five liquid-immersed transformer design lines, three single-phase and two three-phase, as shown in Table 5.3. To capture any design differences between a single-phase pole and a pad-mounted transformer, DOE analyzed units in both DL1 and DL2, spanning the same kVA ratings (10 kVA to 167 kVA). On the three-phase liquid-immersed side, there is no overlap between those two design lines.

Table 5.3 Liquid-Immersed Design Lines and Representative Units

Equipment Class 1 Liquid-Immersed, Single-Phase		
kVA	Rectangular Tank	Round Tank
10	DL 1	DL 2
15	DL 1	DL 2
25	DL 1	DL 2 Rep Unit
37.5	DL 1	DL 2
50	DL 1 Rep Unit	DL 2
75	DL 1	DL 2
100	DL 1	DL 2
167	DL 1	DL 2
250	DL 3	
333	DL 3	
500	DL 3 Rep Unit	
667	DL 3	
833	DL 3	

Equipment Class 2 Liquid-Immersed, Three-Phase	
kVA	Design Lines
15	DL 4
30	DL 4
45	DL 4
75	DL 4
112.5	DL 4
150	DL 4 Rep Unit
225	DL 4
300	DL 4
500	DL 4
750	DL 5
1000	DL 5
1500	DL 5 Rep Unit
2000	DL 5
2500	DL 5

Table 5.4 presents the low-voltage, dry-type design lines. For single-phase units, one design line spans all nine kVA ratings. For the three-phase units, two design lines cover the 11 kVA ratings in that equipment class. There is no overlap in the design lines for low-voltage dry-type transformers.

Table 5.4 Dry-Type, Low-Voltage Design Lines and Representative Units

Equipment Class 3 Dry-Type, Low Voltage, Single-Phase	
kVA	**Design Line**
15	DL 6
25	DL 6 (Rep Unit)
37.5	DL 6
50	DL 6
75	DL 6
100	DL 6
167	DL 6
250	DL 6
333	DL 6

Equipment Class 4 Dry-Type, Low Voltage, Three-Phase	
kVA	**Design Line**
15	DL 7
30	DL 7
45	DL 7
75	DL 7 (Rep Unit)
112.5	DL 7
150	DL 7
225	DL 8
300	DL 8 (Rep Unit)
500	DL 8
750	DL 8
1000	DL 8

As discussed in chapter 3, section 3.4 (National Shipment Estimate), medium-voltage, single-phase, dry-type units have a low shipment volume and low total MVA capacity. All three medium-voltage, single phase, dry type equipment classes together represent less than one-quarter of one percent of dry-type shipments on an MVA capacity basis, and less than one percent of medium-voltage dry-type shipments on an MVA capacity basis. Thus, DOE did not consider it appropriate to conduct a detailed analysis of any units from these three equipment classes.

Table 5.5 presents the equipment classes (abbreviated "EC" in this table) for the medium-voltage, three-phase, dry-type distribution transformers and each of the design lines and respective representative units. Because those equipment classes have high volumes and large ranges of kVA ratings, DOE used two separate design lines for each, to maintain accuracy. Within DL13A, DOE did not extrapolate the results of this unit to ratings of 150kVA and below because there were no shipments at these ratings in the shipments analysis and it is very unlikely that they would be built.

Table 5.5 Dry-Type, Medium-Voltage, Three-Phase Design Lines

Dry-Type, Medium Voltage, Three-Phase			
	EC 6 20-45kV	EC 8 46-95kV	EC 10 ≥96kV
15			-
30			-
45			-
75			-
112.5	DL 9	DL 11	-
150			-
225			
300	Rep Unit	Rep Unit	Rep Unit
500			
750			DL 13 (A & B)
1000			
1500	Rep Unit DL 10	Rep Unit DL 12	
2000			Rep Unit
2500			

5.2.2 Scaling Relationships in Transformer Manufacturing

DOE simplified the engineering analysis by creating design lines, selecting representative units from these design lines, and scaling the results of the analysis on these representative units within their respective design lines. This section briefly introduces the scaling relationship DOE used to extrapolate the findings on the representative units to the other kVA ratings. A more detailed discussion of the derivation of scaling factors is provided in Appendix 5B.

The scaling formulae are mathematical relationships that exist between the kVA ratings and the physical size, cost, and performance of transformers. The size-versus-performance relationships arise from fundamental equations describing a transformer's voltage and kVA rating. For example, when the kVA rating, voltage, and frequency are fixed, the product of the conductor current density, core flux density, core cross-sectional area, and total conductor cross-sectional area is constant.

To illustrate this point, consider a transformer with four fixed variables: frequency, magnetic flux density, current density, and BIL rating. If one enlarges (or decreases) the kVA rating, then the only parameters free to vary are the core cross-section and the core window area through which the windings pass. Thus, to increase (or decrease) the kVA rating, the dimensions for height, width, and depth of the core/coil assembly scale equally in all directions. Analysis of this scaling relationship reveals that each of the linear dimensions varies as the ratio of kVA ratings to the ¼ power. Similarly, areas vary as the ratios of kVA ratings to the ½ power and volumes vary as the ratio of the kVA ratings to the ¾ or 0.75 power, hence the term "0.75 scaling rule." Application of the 0.75 scaling rule assumes that the efficiency profile of a given transformer will have the same shape as the transformer being scaled. Table 5.6 depicts the most common scaling relationships in transformers.

Table 5.6 Common Scaling Relationships in Transformers

Parameter Being Scaled	**Relationship to kVA Rating (varies with ratio of kVA^x)**
Weight	$(kVA_1/kVA_0)^{3/4}$
Cost	$(kVA_1/kVA_0)^{3/4}$
Length	$(kVA_1/kVA_0)^{1/4}$
Width	$(kVA_1/kVA_0)^{1/4}$
Height	$(kVA_1/kVA_0)^{1/4}$
Total Losses	$(kVA_1/kVA_0)^{3/4}$
No-load Losses	$(kVA_1/kVA_0)^{3/4}$

The following three relationships are true as the kVA rating increases or decreases, if the type of transformer (liquid-immersed or dry-type, single-phase or three-phase), the primary voltage, the core configuration, the core material, the core flux density, and the current density (amperes per square inch of conductor cross-section) in both the primary and secondary windings are all held constant:

1. The physical proportions are constant (same relative shape),
2. The eddy loss proportion is essentially constant, and
3. The insulation space factor (voltage or BIL) is constant.

In practical applications, it is rare to find that all of the above are constant over even limited ranges; however, over a range of one order of magnitude in both directions (e.g., from 50 kVA to 5 kVA or from 50 kVA to 500 kVA), the scaling rules shown in Table 5.6 can be used to establish reasonable estimates of performance, dimensions, costs, and losses. In practice, these rules can be applied over even wider ranges to estimate general performance levels.

Although these laws dictate that an ideal transformer will yield a scaling exponent of 0.75, DOE recognizes that a different exponent may produce better behaved results based on real-world engineering. For the NOPR, DOE used unique scaling exponents for each equipment class. For each equipment class DOE derived an exponent to scale relative kVA rating by examining the proposals discussed during the negotiations. Because the proposals discussed during the negotiations included efficiency levels across multiple designs lines, a scaling relationship was implied by the proposal. The exponents used for each equipment class are shown below in Table 5.7.

If one imagines the standard for a particular equipment class as a function on a plot of efficiency (y-axis) versus kVA (x-axis), then the efficiency levels in each design line are a series of points along an imaginary vertical line that intersects the x-axis at the design line's kVA. If there is more than one design line in a given equipment class, there will be more than one series of points. Because exponential scaling is performed on losses and because exponential function will appear as straight lines on logarithmic plots, the concept is more tractable if illustrated that way, as is done in 1 below. Note that efficiency and loss values have a one-to-one correspondence with each other, so one can use whichever coordinate is easier to illustrate identical information. Although standards are ultimately given in terms of efficiency, DOE performs the scaling in loss coordinates. Also note that the following figures are given to illustrate the scaling concept, and have no relation to actual transformer data.

If one is to select efficiency levels for each design line, as was done by the negotiating committee for MVDT transformers, the task remains to scale those chosen efficiencies at certain kVA ratings to all of the other kVA ratings that DOE covers. Drawing a straight line[2] through the chosen points accomplishes that goal, but may produce a slope different from .75.

Deriving the .75 rule requires a number of assumptions to be made, among them that the overall form and proportions of the transformer remain intact as it changes in size. This assumption may break down in a number of ways. For example, MVDT BIL ratings require fixed spacings between the edge of a winding and the window of a core. Proportionally, these fixed values will be much larger for smaller transformers than for larger units. Thus, while the rest of the transformer may behave closer to what the .75 rule would predict, the "fixed" portion will cause losses to fall more slowly with decreasing kVA. Stated alternatively, losses will grow more slowly with increasing kVA and imply a scaling behavior of less than .75.

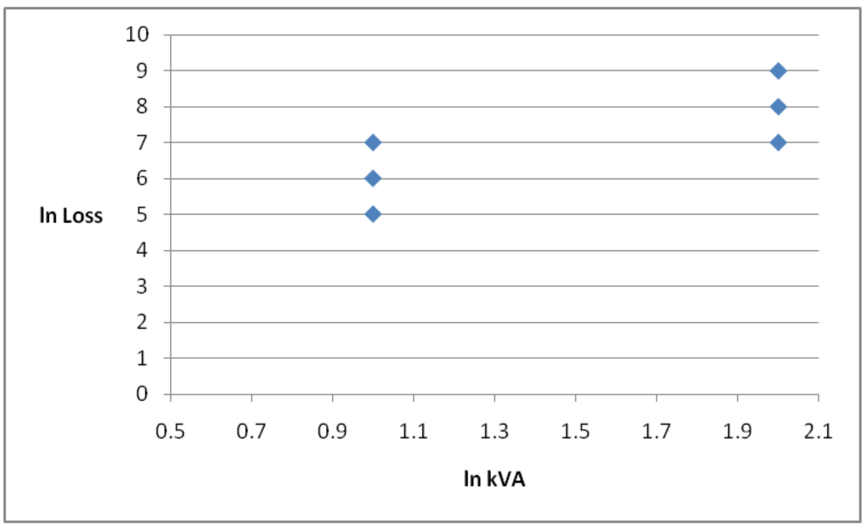

Figure 1 Efficiency Levels within an Equipment Class (Logarithmic)

Table 5.7 Scaling Exponents By Equipment Class

Distribution Transformer Equipment Class	Scaling Exponent
1. Liquid-immersed, medium-voltage, single-phase	.76
2. Liquid-immersed, medium-voltage, three-phase	.79
3. Dry-type, low-voltage, single-phase	.75

[2] A straight line in logarithmic space is an exponential in the original dimensions, which is the logical scaling behavior for transformers to exhibit.

4. Dry-type, low-voltage, three-phase	.67
5. Dry-type, medium-voltage, single-phase, 20-45 kV BIL	.67
6. Dry-type, medium-voltage, three-phase, 20-45 kV BIL	.67
7. Dry-type, medium-voltage, single-phase, 46-95 kV BIL	.67
8. Dry-type, medium-voltage, three-phase, 46-95 kV BIL	.67
9. Dry-type, medium-voltage, single-phase, $\geq$ 96 kV BIL	.68
10. Dry-type, medium-voltage, three-phase, $\geq$ 96 kV BIL	.68

To illustrate how DOE used the scaling exponents, consider two transformers with kVA ratings of S_0 and S_1. The no-load losses (NL) and total losses (TL) of these two transformers would be depicted as NL_0 and TL_0, and NL_1 and TL_1. Then the relationships between the NL and TL of the two transformers could be shown as follows:

Equation 5.2.1

$$NL_1 = NL_0 \times (S_1 / S_0)^E$$

where:

NL_1 = no-load losses of transformer "1,"
NL_0 = no-load losses of transformer "0,"
S_1 = kVA rating of transformer "1," and
S_0 = kVA rating of transformer "0."
E = *Scaling Exponent*

and

Equation 5.2.2

$$TL_1 = TL_0 \times (S_1 / S_0)^E$$

where:

TL_1 = total losses of transformer "1," and
TL_0 = total losses of transformer "0."
E = *Scaling Exponent*

Equation 5.2.1 and Equation 5.2.2 can be manipulated algebraically to show that the load loss also varies to the "E" power. Starting with the concept that total losses equal no-load losses plus load losses, DOE can derive the relationship for load loss (LL), and show that it also scales to the "E" power. Specifically:

Equation 5.2.3

$$LL_1 = TL_1 - NL_1$$

where:

LL_1 = load losses of transformer "1"

Inserting the TL_1 and NL_1 terms into this equation, DOE finds:

Equation 5.2.4

$$LL_1 = (TL_0 \times (S_1 / S_0)^E) - (NL_0 \times (S_1 / S_0)^E)$$

Equation 5.2.5

$$LL_1 = (TL_0 - NL_0) \times (S_1 / S_0)^E$$

Equation 5.2.6

$$LL_1 = (LL_0) \times (S_1 / S_0)^E$$

where:

LL_0 = load losses of transformer "0."

Thus, kVA scaling can be applied to estimate the losses of a transformer, given the losses and kVA rating of a reference (analyzed) unit. However, in order for this rule to be applicable, the transformer type must be the same, and key parameters—such as the type of core material, core flux density, and conductor current density in the high and low voltage windings—must be fixed. Additionally, use of kVA scaling assumes that the efficiency profile of a given transformer will have the same shape as the transformer being scaled. See Appendix 5B for detailed discussion on the derivation of scaling factors.

DOE used the kVA scaling to scale the analysis findings on each of the representative units within the 14 design lines to the 102 kVA ratings that it did not analyze. DOE applied the scaling rule within the design lines in the national impact analysis (chapter 10), where it calculated efficiency ratings for the 102 kVA ratings not analyzed.

5.3 TECHNICAL DESIGN INPUTS FOR SOFTWARE MODEL

For all 14 representative units, the engineering analysis explored the relationship between the manufacturer selling prices and corresponding transformer efficiencies. For this analysis, DOE contracted Optimized Program Service, Inc. (OPS) in Ohio, a software company specializing in transformer design since 1969. Using a range of input parameters and material prices, the OPS software produces a design. This design has specific information about the core and coil, including physical characteristics, dimensions, material requirements, and mechanical clearances, as well as a complete electrical analysis of the final design. This optimized, practical transformer design, the bill of materials, and an electrical analysis report contain sufficient information for a manufacturer to build the unit. DOE uses the software's output to generate an estimated cost of manufacturing materials and labor, which it then converts to a MSP by applying markups.

The electrical analysis report estimates the performance of the transformer design (including efficiency) at 25 percent, 35 percent, 50 percent, 65 percent, 75 percent, 100 percent, 125 percent, and 150 percent of nameplate load. The software output provides a clear understanding of the relationship between cost and efficiency because it provides detailed data on design variances, as well as a bill of materials, labor costs, and efficiency. The software does not capture retooling costs associated with changing production designs for a specific manufacturer. In some cases, however, DOE captured tooling costs associated with manufacturing mitered cores by applying adders to the steel price.

5.3.1 A and B Loss Valuation Inputs

One of the inputs to the design software consisted of a range of what are known in the industry as A and B evaluation combinations (see chapter 3, section 3.6, Total Ownership Cost Evaluation). The combination of A and B input to the design software mimics a distribution transformer purchase order. The A parameter represents a customer's present value of future losses in the transformer core (no-load losses). The B value represents a customer's present value of future losses in the windings (load losses). The B parameter is never larger than A, as this would imply a specification for a transformer whose average load would be more than 100 percent of the nameplate load. The A and B values take into account a range of factors that usually vary from customer to customer.

The A and B values are expressed in terms of dollars per watt of loss. The greater the values of A and B, the greater the importance a customer attaches to the value of future transformer losses. As A and B values increase, the customer places greater importance on reducing the watts of core and winding losses, respectively, and so the customer chooses a more energy-efficient transformer.

DOE used broad ranging combinations of A and B evaluation formulae (presented in Table 5.8 and Table 5.9) to create a complete set of efficiency levels for each design option combination analyzed. The efficiency levels spanned from a low-first-cost unit to a maximum technologically feasible (“max-tech”) design. For the low-first-cost design, the A and B evaluation values were both $0/watt, indicating that the customer does not attach any financial value to future losses in the core or coil of the transformer. For the maximum technologically feasible design, the A and B evaluation values were very high, pushing the software to design at the highest efficiencies achievable.

DOE created its combinations of A and B evaluation formulae combining two techniques to ensure there were sufficient designs in the database for the analysis. The first technique was to create a ‘grid’ of A and B combinations. The ‘grid’ technique involved increasing the value of A by a step value, and then increasing the B value from zero to that value of A, using a different step value. Thus, if A had incremental steps of $0.25 and B had steps of $0.20, the combinations would work as follows: ($0.00, $0.00), ($0.25, $0.00), ($0.25, $0.20), ($0.50, $0.00), ($0.50,

$0.20), ($0.50, $0.40), ($0.75, $0.00), and so on. Table 5.8 presents the ranges and incremental steps for the A and B combinations used in the three grids.

Table 5.8 A and B Grid Combinations Used by Software to Generate Design Database

Grid Number	A values and increments	B values and increments	Resultant # of (A, B) combinations
1	$0 to $2 by 0.25 steps	$0 to $2 by 0.20 steps	47
2	$2.50 to $8 by 0.50 steps	$0 to $8 by 0.40 steps	157
3	$9 to $16 by 1.00 steps	$3 to $8 by 0.50 steps	85

The second technique for generating A and B evaluation formulae in the engineering analysis is called the "fan." DOE understands that the ratio of A to B represents an implicit loading for the transformer. Therefore, DOE created a set of (A, B) values in which the B is calculated from the A. The B term is calculated as the A times the percent load squared. In other words, if A equals $1 and DOE is interested in calculating the appropriate B for a 50 percent root-mean-square (RMS) load, then it would be $1 times (0.50)^2, or $0.25. Thus, the combination of ($1.00, $0.25) represents approximately a 50 percent RMS load. As with the "grid," the A values increased with a step function, and B values were calculated as fractions of A so that the ratio of A to B encompassed the RMS loading points that were identified in DOE's loading analysis (i.e., 35 percent and 50 percent). DOE calculated the B values for each A at the following RMS loading points: 5 percent, 10 percent, 15 percent, 20 percent, 25 percent, 30 percent, 35 percent, 40 percent, 45 percent, 50 percent, 55 percent, and 60 percent. Table 5.9 presents the range of the two fan combinations used in the analysis.

Table 5.9 A and B Fan Combinations Used by Software to Generate Design Database

Fan Number	A values and increments	B values and increments	Resultant # of (A,B) combinations
1	$0 to $2 by 0.50 steps	5% to 60% implicit loading by 5% steps	47
2	$3 to $16 by 1.00 steps	5% to 60% implicit loading by 5% steps	182

When used together, these two techniques created a broad spectrum of A and B combinations as inputs to the OPS software. Figure 2 illustrates the coverage of designs for the 518 A and B combinations. DOE used each of these A and B pairs with each combination of core steel and winding material analyzed for each representative unit studied.

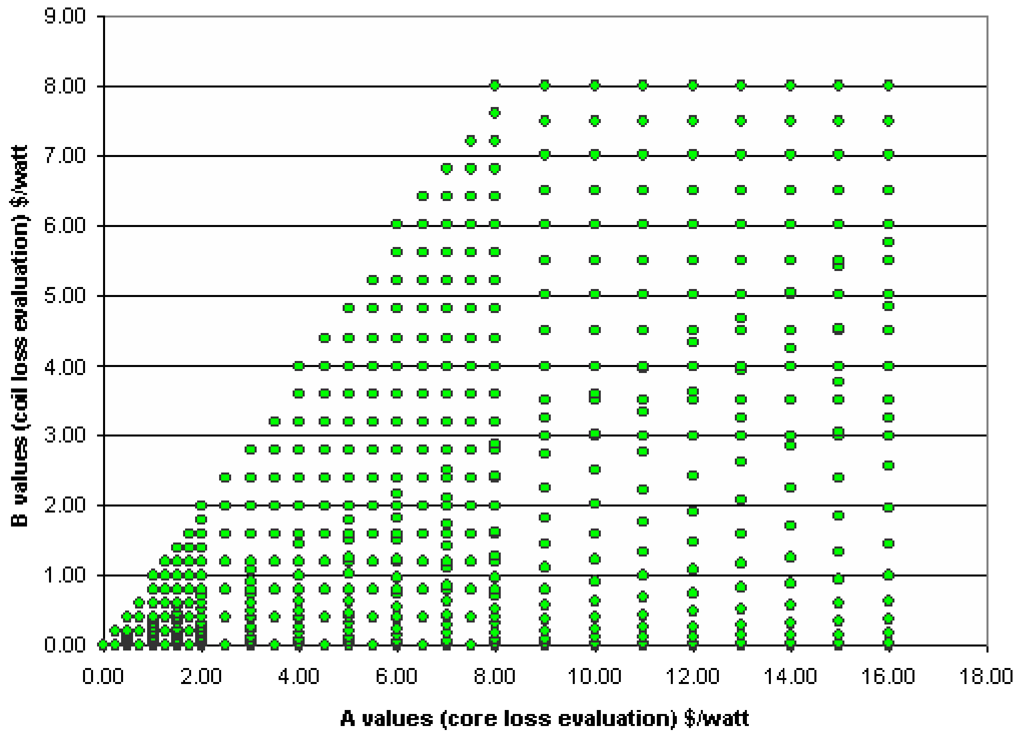

Figure 2 A and B Combination Software Inputs Used in the Engineering Analysis

Occasionally, the design software generated the same transformer design for two different A and B combinations, creating duplicate designs in the engineering analysis database. DOE removed these duplicate designs before the engineering database was imported into the LCC analysis. Similarly, DOE removed any designs that yielded an efficiency value below the current standard level efficiency.

5.3.2 Core Material Options

DOE understands that there are many ways to build a transformer, even with constant kVA and voltage ratings. For instance, manufacturers can vary the core steels (e.g., M2, M3, M6), the winding materials (aluminum or copper), and core configurations (shell or core-type). For each of the design lines, DOE provides tables listing the design option combinations that it used to analyze each of the representative units. Depending on customer needs, the cost of materials, the capital equipment in their facility, and the skills of their labor force, manufacturers make decisions on how to manufacture a given transformer using different core configurations, core steels, and winding materials. To capture this variation in design, DOE analyzed the 14 representative units using 8 – 14 different design option combinations of core type, core steel, and winding material. As discussed in the technology assessment (see chapter 3), core steel is produced in a range of qualities (from an efficiency perspective). M2 core steel is oriented grain silicon steel and has thin laminations, and consequently has very low losses. M12 core steel is non-oriented grain silicon steel and is rolled in thicker laminations, thus contributing to higher core losses. Table 5.10 lists all the steel types used in the analysis, and properties associated with these steels. Each steel grade provides the nominal thickness and core losses per pound of steel, under a specified typical magnetic flux density, measured in Tesla (T).

Table 5.10 Core Steel Grades, Thicknesses and Associated Losses

Steel Grade	**Nominal Thickness** ***inches***	**Core Loss at 60 Hz** ***Watts per Pound at magnetic flux density****	**Notes / Remarks**
M12	0.014	1.36 Watts/lb at 1.5 T	Non-oriented grain silicon steel
M6	0.014	0.60 Watts/lb at 1.5 T 0.84 Watts/lb at 1.7 T	Grain-oriented silicon steel
M5	0.012	0.51 Watts/lb at 1.5 T 0.74 Watts/lb at 1.7 T	Grain-oriented silicon steel
M4	0.011	0.46 Watts/lb at 1.5 T 0.66 Watts/lb at 1.7 T	Grain-oriented silicon steel
M3	0.009	0.39 Watts/lb at 1.5 T 0.60 Watts/lb at 1.7 T	Grain-oriented silicon steel
M2	0.007	0.38 Watts/lb at 1.5 T 0.58 Watts/lb at 1.7 T	Grain-oriented silicon steel
H-0 DR	0.009	0.34 Watts/lb at 1.5 T 0.47 Watts/lb at 1.7 T	Domain-refined, high permeability grade silicon steel
ZDMH	0.009	0.38 Watts/lb at 1.5 T 0.57 Watts/lb at 1.7 T	Imported silicon steel, magnetic domain- refined by mechanical process
SA1	0.001	0.108 Watts/lb at 1.35 T 0.098 Watts/lb at 1.3 T	Amorphous core steel (silicon and boron); flux density limitation - testing at ~ 1.3 T

* Watts of loss per pound of core steel are only comparable at the same magnetic flux density (measured in Tesla).

5.3.3 Core Configurations

In addition to selecting a core steel, the manufacturer's selection of a core design may also contribute to the overall efficiency of a transformer. A transformer facility may be optimized to work around one or two core configurations. Table 5.11 provides a list of all the core configurations used for each of the 14 design lines. DOE selected these configurations, in combination with the range of core steels and winding materials, to represent the most common construction methods for these kVA ratings in the U.S. market.

Table 5.11 Core Configurations Used in Each Design Line

Design Line	# Phases	Core Configurations Used in the Engineering Analysis
DL1	1	Wound core - distributed gap; Shell-type
DL2	1	Wound core - distributed gap; Shell-type or core-type
DL3	1	Wound core - distributed gap; Shell-type or core-type
DL4	3	Wound core - distributed gap; 5-leg
DL5	3	Wound core - distributed gap; 5-leg
DL6	1	Wound core – distributed gap; or stacked butt-lap; Shell-type or core-type
DL7	3	Wound core - distributed gap; or stacked butt-lap, step-lap or full mitered; 3-leg or 5-leg
DL8	3	Wound core - distributed gap; or stacked butt-lap, step-lap or full mitered; 3-leg or 5-leg
DL9	3	Wound core - distributed gap; or stacked full mitered; 3-leg or 5-leg
DL10	3	Wound core – distributed gap; or stacked, cruciform, mitered joint; 3-leg
DL11	3	Wound core – distributed gap; or stacked, step-lap or full mitered; 3-leg or 5-leg
DL12	3	Wound core – distributed gap; or stacked, cruciform or step-lap mitered joint; 3-leg or 5-leg
DL13 (A & B)	3	Wound core – distributed gap; or stacked, cruciform or step-lap mitered joint; 3-leg or 5-leg

5.3.3.1 Standard Core Configurations

For the single-phase representative units, the configurations used are either core-type or shell-type. This applies whether the core consists of stacked or wound laminations of core steel. For wound cores, manufacturers generally employ a technique known as ‘distributed gap.’ This means that each lamination of core steel wound around the form will have a start and finish point (the ‘gap’), staggered with respect to the previous and the next lamination. Distributed gap core construction techniques are used to minimize the performance impact of the lamination joint gaps (reducing the exciting current) and, by locating inside the coil window, reduce the transformer’s operating sound level. Figure 3 illustrates the two types of single-phase core construction.

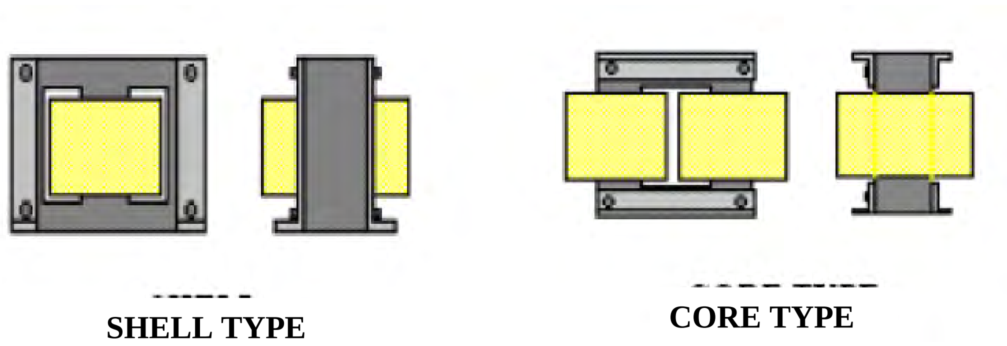

Figure 3 Graphic of Single-Phase Core Configurations

Three-phase transformers can have three-legged, four-legged, five-legged, Evans, or symmetric cores. In the engineering analysis, DOE considered the three-legged construction techniques for the three-phase dry-types and five-legged construction for the three-phase liquid-immersed transformers. Some of the dry-type designs using an amorphous core also use a five-legged construction technique. Figure 4 below illustrates the difference between the three-legged and the five-legged core construction techniques. A three-legged core is assembled from stacked laminations, the joints of which can be butt-lapped or mitered. Where there is an economic need to reduce core losses, particularly in keeping with the use of more efficient grades of core steel (M2 or M3), the mitered core tends to be selected. DOE recognizes that there are a variety of approaches to mitered core construction: “scrapless T-mitering,” “full-mitering,” and “step-mitering.” DOE modeled full-mitered and step-mitered cores.

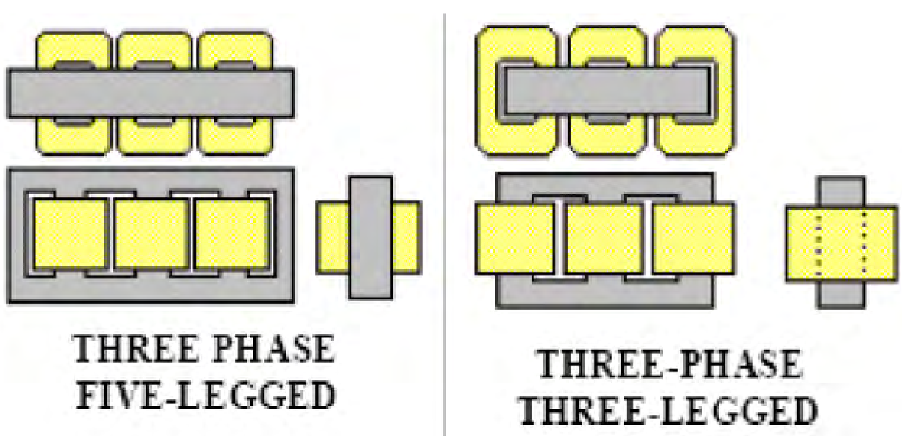

Figure 4 Graphic of Three-phase Core Configurations

For larger kVA ratings, design economics may cause the selection of a cruciform core section, where multiple lamination widths are stacked in increasing and then decreasing widths to create a circular core form (or “log”) around which the windings are placed. Figure 5 illustrates the cruciform core by showing a cross-section. This figure shows four different widths of steel being used, but there can be fewer or more widths, depending on the design. By using a core configuration that better follows the contours of the windings, losses are again reduced, resulting in a more efficient transformer. The use of the three-legged core usually depends on the primary winding being delta-connected. If the primary winding is wye-connected, as is frequently the case for pad-mounted transformers used in underground distribution, the core configuration needs to be four-legged or five-legged.

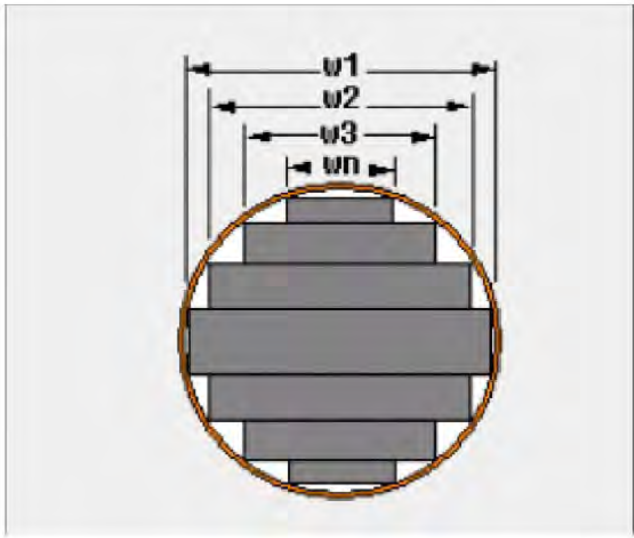

Figure 5 Cruciform Core Cross-Section

The five-legged core is assembled from four wound-core loops, and is the common configuration for liquid-filled, three-phase distribution transformers having a wye-wye voltage connection. Again, this occurs for pad-mounted transformers used in underground distribution. The individual core loops have distributed gaps, as explained for single-phase, wound-core transformers.

5.3.3.2 Symmetric Core Configurations

Transformers with symmetric core configurations use continuously wound cores with 120 degree radial symmetry, where no one leg is magnetically distinguishable from the other two. . Following the preliminary analysis, DOE was unable to identify a company with commercial modeling software that could model symmetric core designs. DOE did speak with transformer manufacturers and industry experts about symmetric core designs. Through these conversations, DOE received information on a few symmetric core designs. These designs were insufficient to conduct a full-scale engineering analysis comparable to the other design types. In the preliminary analysis, DOE was able to approximate the cost-efficiency relationship for symmetric core designs based on trends in the data received from manufacturers, published literature, and through conversations with industry experts. However, because the data was so limited and DOE did not receive any additional information from manufacturers, DOE did not consider symmetric core designs in this stage of the rulemaking. .

5.3.4 Less-Flammable Liquid-Immersed Transformers

For liquid-immersed distribution transformers, DOE studied the differences between mineral oil cooled units and less-flammable cooled units. DOE understands that the IEEE standard C57.12.80 divides less-flammable liquid-immersed (LFLI) transformers into two groups: KNAN (which have an insulating liquid with a fire point greater than 300 degrees Celsius) and LNAN (which have an insulating liquid with no measurable fire point). The fire point for mineral oil is approximately 175 degrees Celsius, and therefore this type of transformer is not used inside buildings or in areas designated as hazardous. While industry has a specification for KNAN for a certain degree of fire protection or LNAN for users who prefer an extra measure of safety, DOE will continue to refer to both KNAN and LNAN using the phrase 'less-flammable,' or LFLI.

DOE understands that the viscosity of the insulating liquid can have a slight impact on the efficiency of a transformer. When the viscosity is higher than mineral oil, transformer designers must make slightly larger cooling ducts to permit an easier flow of the fluid. Larger ducts result in larger physical size of the winding assembly and a greater mean number of turns of the conductor, therefore contributing to a slightly higher load loss. However, as efficiency increases, the transformer will run cooler, which negates part of the need for larger cooling ducts. As such, LFLI transformers are still able to achieve the same efficiency levels as transformers using mineral oil. DOE verified this fact through conversations with manufacturers and industry experts. In fact, DOE was informed that LFLI transformers might be capable of higher efficiencies than mineral oil units since their higher temperature tolerance may allow the unit to be downsized and run hotter than mineral oil units.

For the KNAN transformers (i.e., those with a fire point of 300 degrees or greater), DOE is not aware of any viscosity differences with mineral oil that might impede designs or make efficiency levels significantly more difficult to reach. For LNAN transformers (i.e., those with no fire point), DOE understands that the viscosity under usual operating conditions is slightly greater than that of mineral oil, which may require design engineers to increase the duct size, leading to a marginal impact on efficiency. However, as explained above, DOE believes this increased viscosity is offset by the cooler operating temperature, which could allow the transformer to be downsized and run hotter. This would negate any impact on efficiency. Chapter 2 provides additional discussion of less-flammable liquid-immersed transformers.

5.3.5 Design Line 1 Representative Unit

Design line 1 (DL1) represents rectangular-tank, liquid-immersed, single-phase distribution transformers, ranging from 10 kVA to 167 kVA. The representative unit selected for this design line is a 50kVA pad-mounted unit. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 50 (liquid-immersed, rectangular-tank)
Primary: 14400 Volts at 60 Hz
Secondary: 240/120V
T Rise: 65˚C

Ambient: 20˚C
Winding Configuration: Lo-Hi-Lo (Shell-Type)
Core: Wound core - distributed gap
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 1.5–4.5 percent
BIL: 95 kV

For DL1, DOE selected nine design option combinations,based on input from manufacturers and other technical experts. The core selected was shell-type, because the application is for a pad-mounted unit, and this shape is well suited to a rectangular tank. With the exception of the max-tech/high efficiency designs, DOE selected nine design option combinations to represent the most common construction practices for this representative unit.

Table 5.12 Design Option Combinations for the Design Line 1 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Cu – wire	Al – strip	Shell – DG* Wound Core
M3	Al – wire	Al – strip	Shell – DG Wound Core
M3	Cu – wire	Al – strip	Shell – DG Wound Core
M2	Al – wire	Al – strip	Shell – DG Wound Core
M2	Cu – wire	Al – strip	Shell – DG Wound Core
ZDMH	Al – wire	Al – strip	Shell – DG Wound Core
ZDMH	Cu – wire	Cu – strip	Shell – DG Wound Core
SA1 (Amorphous)	Al – wire	Al – strip	Shell – DG Wound Core
SA1 (Amorphous)	Cu – wire	Cu – strip	Shell – DG Wound Core

* DG – Distributed gap wound core construction, where the core laminations are wound in such a way that the gap between the start and finish of a lamination is staggered in the cross-section of the core.

DOE analyzed each of the nine design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 1,924 designs.

5.3.6 Design Line 2 Representative Unit

Design line 2 (DL2) represents round-tank, liquid-immersed, single-phase distribution transformers, ranging from 10 kVA to 167 kVA. The representative unit selected for this design line is a 25kVA pole-mounted unit. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 25 (liquid-immersed, round-tank)
Primary: 14400 Volts at 60 Hz (125 kV BIL)
Secondary: 120/240V
T Rise: 65˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi-Lo (Shell-Type), Lo-Hi (Core-Type, for amorphous core)
Core: Wound core - distributed gap
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 1.0–4.5 percent
BIL: 125 kV

For DL2, DOE selected eleven design option combinations, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practices for the representative unit.

Table 5.13 Design Option Combinations for the Design Line 2 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Cu – wire	Al – strip	Shell – DG Wound Core
M4	Al – wire	Al – strip	Shell – DG Wound Core
M4	Cu – wire	Al – strip	Shell – DG Wound Core
M3	Al – wire	Al – strip	Shell – DG Wound Core
M3	Cu – wire	Al – strip	Shell – DG Wound Core
M2	Al – wire	Al – strip	Shell – DG Wound Core
M2	Cu – wire	Al – strip	Shell – DG Wound Core
ZDMH	Al – wire	Al – strip	Shell – DG Wound Core
ZDMH	Cu – wire	Cu – strip	Shell – DG Wound Core
SA1 (Amorphous)	Al – wire	Al – strip	Core – DG Wound Core
SA1 (Amorphous)	Cu – wire	Cu – strip	Core – DG Wound Core

DOE analyzed each of the eleven design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 2,301designs.

5.3.7 Design Line 3 Representative Unit

Design line 3 (DL3) represents round-tank, liquid-immersed, single-phase distribution transformers, ranging from 250 kVA to 833 kVA. The representative unit selected for this design line is a 500kVA round-tank transformer. The following are the technical specifications which constitute input parameters to the OPS design software:

KVA: 500 (liquid-immersed, round-tank)
Primary: 14400 Volts at 60 HZ (150kV BIL)
Secondary: 277 Volts
T Rise: 65˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi (Shell-Type and Core-Type)
Core: Wound core - distributed gap
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 1.5–7.0 percent
BIL: 150 kV

For DL3, DOE selected twelve design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE chose design option combinations to represent the most common construction practice for this representative unit.

Table 5.14 Design Option Combinations for the Design Line 3 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Cu – wire	Al – strip	Shell – DG Wound Core
M4	Al – wire	Al – strip	Shell – DG Wound Core
M4	Cu – wire	Al – strip	Shell – DG Wound Core
M3	Al – wire	Al – strip	Shell – DG Wound Core
M3	Cu – wire	Al – strip	Shell – DG Wound Core
M2	Al – wire	Al – strip	Shell – DG Wound Core
M2	Cu – wire	Al – strip	Shell – DG Wound Core
ZDMH	Al – wire	Al – strip	Shell – DG Wound Core
ZDMH	Cu – wire	Cu – strip	Shell – DG Wound Core
SA1 (Amorphous)	Al – wire	Al – strip	Core – DG Wound Core
SA1 (Amorphous)	Cu – wire	Cu – strip	Shell – DG Wound Core
SA1 (Amorphous)	Cu – wire	Cu – strip	Core – DG Wound Core

DOE analyzed each of the twelve design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 2,740 designs.

5.3.8 Design Line 4 Representative Unit

Design line 4 (DL4) represents rectangular tank, liquid-immersed, three-phase distribution transformers, ranging from 15 kVA to 500 kVA. The representative unit selected for this design line is a 150kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 150 (liquid-immersed, pad mount)
Primary: 12470Y/7200 Volts at 60 Hz (95kV BIL)
Secondary: 208Y/120 Volts
T Rise: 65˚C
Ambient: 20˚C
Terminal Configuration: ANSI/IEEE C57.12.26, Loop Feed
Winding Configuration: Lo-Hi
Core: Wound core - distributed gap, 5-leg
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 1.2-6.0 percent
BIL: 95 kV

For DL4, DOE selected nine design option combinations of core steel and winding types based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.15 Design Option Combinations for the Design Line 4 Representative Unit

Core Material	**High-Voltage Conductor**	**Low-Voltage Conductor**	**Core Design Type**
M5	Cu – wire	Al – strip	5-Leg DG Core
M3	Al – wire	Al – strip	5-Leg DG Core
M3	Cu – wire	Al – strip	5-Leg DG Core
M2	Al – wire	Al – strip	5-Leg DG Core
M2	Cu – wire	Al – strip	5-Leg DG Core
ZDMH	Al – wire	Al – strip	5-Leg DG Core
ZDMH	Cu – wire	Cu – strip	5-Leg DG Core
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	5-Leg DG Core

DOE analyzed each of the nine design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 1,977 designs.

5.3.9 Design Line 5 Representative Unit

Design line 5 (DL5) represents rectangular tank, liquid-immersed, three-phase distribution transformers, ranging from 750 kVA to 2500 kVA. The representative unit selected for this design line is a 1500kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 1500 (liquid-immersed, pad mount)
Primary: 24940GrdY/14400 Volts (125kV BIL)
Secondary: 480Y/277 Volts
T Rise: 65˚C
Ambient: 20˚C
Terminal Configuration: ANSI/IEEE C57.12.26, Loop Feed
Winding Configuration: Lo-Hi
Core: Wound core - distributed gap, 5-leg
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 5-7.5 percent
BIL: 125 kV

For DL5, DOE selected nine design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practices for the representative unit.

Table 5.16 Design Option Combinations for the Design Line 5 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M4	Cu – wire	Al – strip	5-Leg DG Core
M3	Al – wire	Al – strip	5-Leg DG Core
M3	Cu – wire	Al – strip	5-Leg DG Core
M2	Al – wire	Al – strip	5-Leg DG Core
M2	Cu – wire	Al – strip	5-Leg DG Core
ZDMH	Al – wire	Al – strip	5-Leg DG Core
ZDMH	Cu – wire	Cu – strip	5-Leg DG Core
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	5-Leg DG Core

DOE analyzed each of the nine design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 1,294 designs.

5.3.10 Design Line 6 Representative Unit

Design line 6 (DL6) represents ventilated dry-type, single-phase, low-voltage distribution transformers, ranging from 15 kVA to 333 kVA. The representative unit selected for this design line is a 25 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 25 (dry-type)
Phases: Single
Primary: 480 Volts at 60 Hz (10 kV BIL)
Secondary: 120/240 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi (for Core-Type and Shell-Type)
Core: Stacked, butt-lap; Wound core - distributed gap
Taps: Six 2½ percent, two above and four below the nominal
Impedance Range: 1.5-6.0 percent

For DL6, DOE selected ten design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.17 Design Option Combinations for the Design Line 6 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M6	Al – wire	Al – wire	Stacked Core Butt-lap
M5	Al – wire	Al – strip	Stacked Core Butt-lap
M4	Al – wire	Al – wire	Stacked Core Butt-lap
M3	Al – wire	Al – strip	Stacked Core Butt-lap
M3	Cu – wire	Al – wire	Stacked Core Butt-lap
M3	Cu – wire	Al – wire	Stacked Shell Butt-lap
H-0 DR*	Al – wire	Al – strip	Stacked Core Butt-lap
H-0 DR	Cu – wire	Cu – wire	Stacked Core Butt-lap
SA1 (Amorphous)	Al – wire	Al – strip	Core – DG Wound Core
SA1 (Amorphous)	Cu – wire	Cu – wire	Core – DG Wound Core

* H-0 DR is a domain-refined, high permeability core steel.

DOE analyzed each of the ten design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 3,091 designs.

5.3.11 Design Line 7 Representative Unit

Design line 7 (DL7) represents ventilated dry-type, three-phase, low-voltage distribution transformers, ranging from 15 kVA to 150 kVA. The representative unit selected for this design line is a 75 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 75 (dry-type)
Phases: Three
Primary: 480 Volts at 60 Hz (10 kV BIL)
Secondary: 208Y/120 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, butt-lap; Stacked, mitered; Wound core - distributed gap
Taps: Six 2½ percent, two above and four below the nominal
Impedance Range: 1.5–6.0 percent

For DL7, DOE selected twelve design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.18 Design Option Combinations for the Design Line 7 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M12	Al – wire	Al – wire	3-Leg Stacked Butt-lap
M12	Cu – wire	Al – wire	3-Leg Stacked Butt-lap
M6	Al – wire	Al – wire	3-Leg Stacked Butt-lap
M6	Al – wire	Al – wire	3-Leg Stacked Full Miter**
M4	Cu – wire	Al – wire	3-Leg Stacked Full Miter
M3	Al – wire	Al – wire	3-Leg Stacked Full Miter
M3	Al – wire	Al – wire	3-Leg Step-Lap Miter
H-0 DR*	Al – wire	Al – strip	3-Leg Stacked Full Miter
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR	Cu – wire	Cu – wire	3-Leg Stacked Full Miter
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – wire	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.
** Full miters are not step-miters, but are mitered joints for all three legs. These cores are stacked three by three.

DOE analyzed each of the twelve design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 1,634 designs.

For the NOPR, DOE filtered out a number of transformer designs with high flux density from DL7. . Based on comments in negotiations, DOE removed designs over a certain flux density to maintain consistency with designs submitted by manufacturers. . There is a variety of reasons that manufacturers would choose to limit flux density (e.g. vibration and noise). . Designs using conventional steels begin to experience these issues at flux densities over 1.3 Tesla; while those with domain-refined high permeability core steels see issues starting at 1.5 Tesla. . Designs that use amorphous metal have naturally lower flux densities, and therefore do not often experience these issues. . DOE set the flux density limitations described in TABLE XX.

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type	Flux Density Limit
M12	Al – wire	Al – wire	3-Leg Stacked Butt-lap	1.3
M12	Cu – wire	Al – wire	3-Leg Stacked Butt-lap	1.3
M6	Al – wire	Al – wire	3-Leg Stacked Butt-lap	1.3
M6	Al – wire	Al – wire	3-Leg Stacked Full Miter**	1.3
M4	Cu – wire	Al – wire	3-Leg Stacked Full Miter	1.3
M3	Al – wire	Al – wire	3-Leg Stacked Full Miter	1.3
M3	Al – wire	Al – wire	3-Leg Step-Lap Miter	1.3
H-0 DR*	Al – wire	Al – strip	3-Leg Stacked Full Miter	1.5
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter	1.5
H-0 DR	Cu – wire	Cu – wire	3-Leg Stacked Full Miter	1.5
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core	No limit set
SA1 (Amorphous)	Cu – wire	Cu – wire	5-Leg DG Core	No limit set

5.3.12 Design Line 8 Representative Unit

Design line 8 (DL8) represents ventilated dry-type, three-phase, low-voltage distribution transformers, ranging from 225 kVA to 1000 kVA. The representative unit selected for this design line is a 300 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 300 (dry-type)
Phases: Three
Primary: 480V at 60 Hz (10 kV BIL) Delta Connected
Secondary: 208Y/120 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, butt-lap; Stacked, mitered; Wound core - distributed gap
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 3.0–7.0 percent

For DL8, DOE selected fourteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.19 Design Option Combinations for the Design Line 8 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M6	Al – wire	Al – strip	3-Leg Stacked Butt-lap
M6	Al – wire	Al – strip	3-leg Stacked Full Miter
M6	Cu – wire	Cu – strip	3-Leg Stacked Full Miter**
M5	Al – wire	Al – strip	3-Leg Stacked Butt-lap
M5	Al – wire	Al – strip	3-Leg Stacked Full Miter
M4	Cu – wire	Al – strip	3-Leg Stacked Full Miter
M3	Al – wire	Al – strip	3-Leg Stacked Full Miter
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Cu – wire	Al – strip	3-Leg Stacked Full Miter
H-0 DR*	Al – wire	Al – strip	3-Leg Stacked Full Miter
H-0 DR	Al – wire	Al – strip	5-Leg Step-Lap Miter
H-0 DR	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.
** Full miters are not step-miters, but are mitered joints for all three legs. These cores are stacked three by three.

DOE analyzed each of the fourteen design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 4,443 designs.

5.3.13 Design Line 9 Representative Unit

Design line 9 (DL9) represents ventilated dry-type, three-phase, medium-voltage distribution transformers with a 20-45kV BIL, ranging from 15 kVA to 500 kVA. The representative unit selected for this design line is a 300 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 300 (dry-type)
Phases: Three
Primary: 4160V at 60 Hz (45 kV BIL) Delta Connected
Secondary: 480Y/277 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, mitered; Wound core - distributed gap
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 3.0–7.0 percent

For DL9, DOE selected thirteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.20 Design Option Combinations for the Design Line 9 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M6	Cu – wire	Cu – wire	3-Leg Stacked Full Miter**
M5	Al – wire	Al – wire	3-Leg Stacked Full Miter
M4	Al – wire	Al – wire	3-Leg Step-Lap Miter
M3	Al – wire	Al – strip	3-Leg Stacked Full Miter
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Al – wire	Al – strip	5-Leg DG Core
M3	Cu – wire	Al – strip	3-Leg Stacked Full Miter
H-0 DR*	Al – wire	Al – strip	3-Leg Stacked Full Miter
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	3-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.
** Full miters are not step-miters, but are mitered joints for all three legs. These cores are stacked three by three.

DOE analyzed each of the thirteen design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 5,600 designs.

5.3.14 Design Line 10 Representative Unit

Design line 10 (DL10) represents dry-type, three-phase, medium-voltage distribution transformers with a 20-45kV BIL, ranging from 750 kVA to 2500 kVA. The representative unit selected for this design line is a 1500 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 1500 (dry-type)
Phases: Three
Primary: 4160V at 60 Hz (45 kV BIL)
Secondary: 480Y/277 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, cruciform, mitered joint, 3-leg; Wound core - distributed gap
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 5.0-8.0 percent

For DL10, DOE selected eleven design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.21 Design Option Combinations for the Design Line 10 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Cu – wire	Al – strip	3-Leg Mitered Cruciform
M4	Al – wire	Al – strip	3-Leg Step-Lap Miter
M4	Cu – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Cu – wire	Cu – strip	3-Leg Mitered Cruciform
H-0 DR*	Al – wire	Al – strip	3-Leg Mitered Cruciform
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR	Cu – wire	Cu – strip	3-Leg Mitered Cruciform
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	3-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.

DOE analyzed each of the eleven design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 2,501 designs.

5.3.15 Design Line 11 Representative Unit

Design line 11 (DL11) represents dry-type, three-phase, medium-voltage distribution transformers with a 46-95kV BIL, ranging from 15 kVA to 500 kVA. The representative unit selected for this design line is a 300 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 300 (dry-type)
Phases: Three
Primary: 12470 Volts at 60 Hz (95 kV BIL)
Secondary: 480Y/277 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, mitered joint, 3-leg; Wound core - distributed gap, 5-leg
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 3.0-7.0 percent

For DL11, DOE selected eleven design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.22 Design Option Combinations for the Design Line 11 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M6	Cu – wire	Cu – strip	3-Leg Stacked Full Miter**
M4	Al – wire	Al – strip	3-Leg Step-Lap Miter
M4	Cu – wire	Al – strip	3-Leg Stacked Full Miter
M3	Al – wire	Al – strip	3-Leg Stacked Full Miter
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
H-0 DR*	Al – wire	Al – strip	3-Leg Stacked Full Miter
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
SA1 (Amorphous)	Al – wire	Al – strip	3-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.
** Full miters are not step-miters, but are mitered joints for all three legs. These cores are stacked three by three.

DOE analyzed each of the eleven design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 1,896 designs.

5.3.16 Design Line 12 Representative Unit

Design line 12 (DL12) represents dry-type, three-phase, medium-voltage distribution transformers with a 46-95kV BIL, ranging from 750 kVA to 2500 kVA. The representative unit selected for this design line is a 1500 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 1500 (dry-type)
Phases: Three
Primary: 12470 Volts at 60 Hz (95 kV BIL)
Secondary: 480Y/277 Volts

T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, cruciform, mitered joint, 3-leg; Wound core - distributed gap, 5-leg
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 5.0–8.0 percent

For DL12, DOE selected eleven design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.23 Design Option Combinations for the Design Line 12 Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Al – wire	Al – strip	3-Leg Mitered Cruciform
M4	Al – wire	Al – strip	3-Leg Step-Lap Miter
M4	Cu – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Cu – wire	Cu – strip	3-Leg Mitered Cruciform
H-0 DR*	Al – wire	Al – strip	3-Leg Mitered Cruciform
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR	Cu – wire	Cu – strip	3-Leg Mitered Cruciform
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core
SA1 (Amorphous)	Cu – wire	Cu – strip	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.

DOE analyzed each of the eleven design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 3,393 designs.

5.3.17 Design Line 13A Representative Unit

Design line 13A (DL13A) represents dry-type, three-phase, medium-voltage distribution transformers with a ≥96kV BIL, ranging from 225 kVA to 2500 kVA. The representative unit selected for this design line is a 300 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 300 (dry-type)
Phases: Three
Primary: 24940 Volts at 60 Hz (125 kV BIL)
Secondary: 480Y/277 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, cruciform, mitered joint, 3-leg; Wound core - distributed gap, 5-leg
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 3.0–7.0 percent

For DL13A, DOE selected seven design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.24 Design Option Combinations for the Design Line 13A Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Al – wire	Al – strip	3-Leg Mitered Cruciform
M4	Al – wire	Al – strip	3-Leg Mitered Cruciform
M4	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Al – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR*	Al – wire	Al – strip	3-Leg Mitered Cruciform
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.

DOE analyzed each of the seven design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 831 designs.

5.3.18 Design Line 13B Representative Unit

Design line 13B (DL13B) also represents dry-type, three-phase, medium-voltage distribution transformers with a ≥96kV BIL, ranging from 225 kVA to 2500 kVA. The representative unit selected for this design line is a 2000 kVA transformer. The following are the technical specifications that constitute input parameters to the OPS design software:

KVA: 2000 (dry-type)
Phases: Three
Primary: 24940 Volts at 60 Hz (125 kV BIL)
Secondary: 480Y/277 Volts
T Rise: 150˚C
Ambient: 20˚C
Winding Configuration: Lo-Hi
Core: Stacked, cruciform, mitered joint, 3-leg; Wound core - distributed gap, 5-leg
Taps: Four 2½ percent, two above and two below the nominal
Impedance Range: 5.0–8.0 percent

For DL13B, DOE selected eight design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. With the exception of the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.20 Design Option Combinations for the Design Line 13B Representative Unit

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M5	Al – wire	Al – strip	3-Leg Mitered Cruciform

M4	Al – wire	Al – strip	3-Leg Mitered Cruciform
M4	Al – wire	Al – strip	3-Leg Step-Lap Miter
M3	Al – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
H-0 DR*	Al – wire	Al – strip	3-Leg Mitered Cruciform
H-0 DR	Al – wire	Al – strip	3-Leg Step-Lap Miter
SA1 (Amorphous)	Al – wire	Al – strip	5-Leg DG Core

* H-0 DR is a domain-refined, high permeability core steel.

DOE analyzed each of the eight design option combinations using the matrix of A and B values described in Table 5.8 and Table 5.9, creating 1,881 designs.

5.3.19 Newly Optimized Designs and Previously Optimized Designs

DOE utilized a combination of newly optimized design runs and designs that were optimized during the preliminary analysis for distribution transformers. For each design option combination chosen, DOE generates designs based on 518 A and B factor combinations. These A and B factor combinations cover the spectrum of typical load loss and no-load loss valuations, generating a unique design across a range of efficiencies.

DOE understands that typically a design would be optimized based on the current material prices. Optimizing a design based on historical material prices may result in a differently optimized design, such as a design that utilizes relatively more conductor than core. However, DOE believes that it adequately covered the spectrum of possible designs for each design option combination used in the preliminary analysis based on the large sample of A and B factor combinations considered for each design option combination. As such, DOE believes that these designs are still valid when updated material prices are applied to them.

DOE updated the cost of these previous design runs by applying updated prices to the design's bill of materials. Effectively, DOE calculated the present cost of developing the same design that was used in the preliminary analysis. DOE also updated labor prices and applied the markups consistently with any newly optimized designs generated for the NOPR analysis.

While DOE believes that its approach of reusing previously optimized designs with updated material prices is reasonable, it plans to create newly optimized designs for the analysis as well. Currently, DOE has added in several new design option combinations, which are modeled with a newly optimized design. Additionally, DOE may choose to re-optimize the designs from the preliminary analysis rather than simply updating their material prices as the analysis progresses.

5.3.20 Design Option Combinations

Following the preliminary analysis, DOE made several changes to the design option combinations used for each design line. . These decisions were made based on a combination of manufacturer feedback, comments on the preliminary analysis, and feedback from negotiations.

In some cases, DOE chose to eliminate a design option combination used previously, based on various reasons (lack of feasibility, material availability, etc.). .

DOE chose to eliminate several wound core designs from their analysis. . It considered analyzing wound core designs for all of dry-type units less than 300 kVA in the preliminary analysis. . However, . DOE understands that wound core construction is uncommon and entails some additional capital investments that would make direct comparison with stacked construction sensitive to differential assumptions about the size and nature of those investments. DOE believes that the incremental costs for each construction type to be similar such that downstream economic results would be relatively unaffected. Similarly, DOE chose to eliminate wound core ZDMH and M3 designs from all low-voltage dry-type design lines based on limited availability. . DOE felt it was unrealistic to compare them to other transformer designs without major adjustments. . For larger dry-type transformers (DL10, DL12, DL13B) DOE did not consider wound core designs. . Large dry-type wound-core transformers will emit audible “buzzing” and have an efficiency penalty that grows with kVA rating. . This makes stacked core significantly more attractive for large dry-type transformers. . However, DOE did continue to consider wound core amorphous designs in each dry-type design line because it represented the theoretical maximum technology feasible.

DOE also chose to include step-lap miter designs for its dry-type design lines based on feedback from manufacturers. . Stakeholders noted in negotiations that step-lap miter designs could potentially yield greater efficiencies than fully-mitered designs. . However, in smaller dry-type designs step-lap mitering may not be cost effective. . In these designs, the smaller average steel piece size results in a larger destruction factor, and larger losses. . For this reason, DOE choose to exclude step-lap miter designs from design line 6, a 25 kVA unit.

Finally, based on feedback in negotiations, DOE choose to add certain design option combinations that they understood to be prevalent baseline options in the current market. . For all medium-voltage, dry-type design lines (9-13B), DOE added a M4 step-lap mitered core design option combination with aluminum primary and secondary windings. . Additionally, DOE added a M6 fully mitered core design option combination with aluminum primary and secondary windings for design line 8. . It is DOE’s understanding that both of these designs are popular choices at the current standard levels. .

These changes are summarized in Table 5.25 below.

Table 5.25 Design Option Combination Updates in the NOPR

Design Type	Design Group	Status for NOPR
Wound Core ZDMH and M3	Dry-type	Removed
Step-lap Miter designs	Small kVA dry-type (DL6)	Removed
M4AlAl Step-lap Miter	Medium-voltage dry-type	Added
M6AlAl Fully Mitered	DL8	Added

5.4 MATERIAL AND LABOR INPUTS

DOE uses a standard method of cost accounting with minor changes to determine the costs associated with manufacturing. This methodology is illustrated in Figure 5.4.1, where production costs and non-production costs are combined to determine the manufacturer's selling price of the equipment.

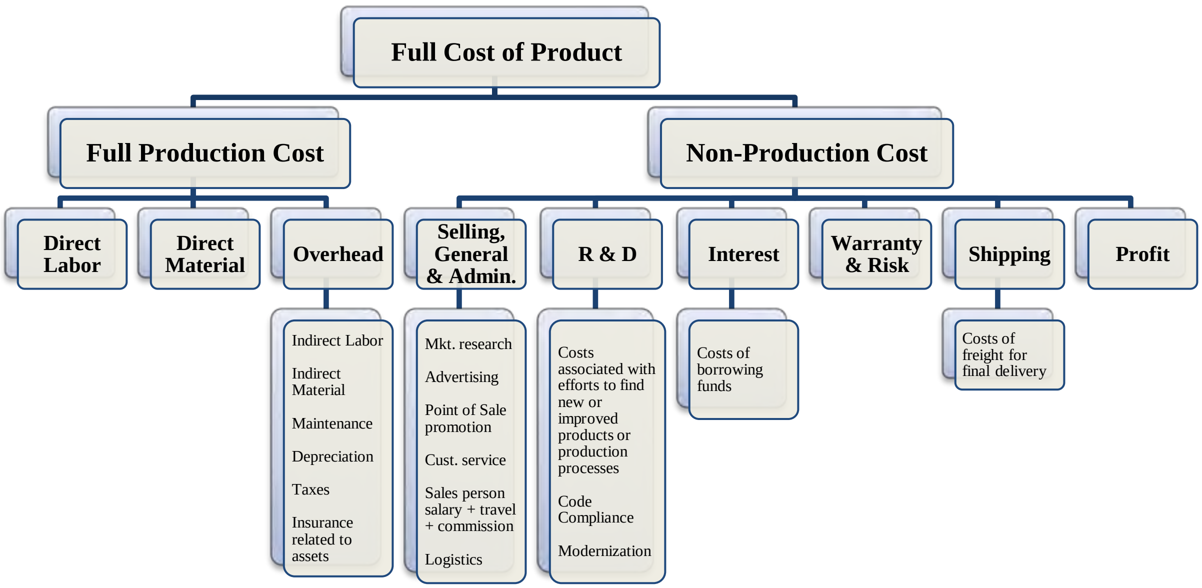

Figure 5.4.1 Method of Cost Accounting for Distribution Transformers Rulemaking

Together, the full production cost and the non-production cost equal the manufacturer's selling price of the equipment. Full production cost is a combination of direct labor, direct materials, and overhead. The overhead contributing to full production cost includes indirect labor, indirect material, maintenance, depreciation, taxes, and insurance related to company assets. Non-production cost includes the cost of selling, general and administrative items (market research, advertising, sales representatives, logistics), research and development (R&D), interest payments, warranty and risk provisions, shipping, and profit factor. Because profit factor is included in the non-production cost, the sum of production and non-production costs is an estimate of the manufacturer's selling price.

DOE used several estimates of the costs listed in Figure 5.4.1 from DOE's previous rulemaking on distribution transformers, published in October 2007. The estimates from this rulemaking relied on U.S. Industry Census Data Reports, manufacturer interviews, and Securities and Exchange Commission (SEC) 10-K reports for several manufacturers. It then refined these estimates through meetings and dialogue with transformer manufacturers in 2010. The following markups resulted:

- Scrap and handling factor: 2.5 percent markup. This markup applies to variable materials (e.g., core steel, windings, insulation). It accounts for the handling of material (loading into assembly or winding equipment) and the scrap material that cannot be used in the production of a finished transformer (e.g., lengths of wire too short to wind, trimmed core steel).

- Amorphous scrap factor: 1.5 percent markup. This markup accounts for breakage of prefabricated amorphous cores and any scrap associated with assembling the windings on the core. Since amorphous cores are assumed to be prefabricated, the regular scrap and handling factor is reduced.

- Mitered scrap factor: 4.0 percent markup. An additional scrap markup applies to steel used in full-mitered cores. This markup represents material cut from the notch in the yoke.

- Factory overhead: 12.5 percent markup. Factory overhead includes all the indirect costs associated with production, indirect materials and energy use (e.g., annealing furnace), taxes, and insurance. DOE only applied factory overhead to the direct material production costs.

- Shipping: $0.28 per pound for each transformer. The shipping costs include the freight from a manufacturer's facility to the customer. This shipping cost does not include any freight charges for the customer to subsequently move the transformer to its end-use location. DOE applied the shipping charge prior to applying the profit markup based on feedback from manufacturer interviews in 2011.

- Non-production: 25 percent markup. This markup reflects costs including selling, general and administrative, R&D, interest payments, warranty and risk provisions, and profit factor. DOE applied the non-production markup to the sum of direct material, direct labor, and factory overhead.

The following example shows how DOE applied the markups to the materials, and how it determined the manufacturer selling price. Consider a 300kVA 45kV BIL three-phase, dry-type transformer designed with a $1.50 A and a $0.30 B. This design has $4,795 of materials, including M6 core steel, copper primary and secondary windings, and all the transformer hardware. There are approximately 27 hours of labor involved in manufacturing this design, resulting in a labor cost of $1,361. The factory overhead on this design is $599, as it is only applied to the material cost (i.e., 12.5 percent of $4,795). The shipping cost is $504, based on a weight of 1,792 pounds. The non-production cost is $1,706, since the 25 percent is applied to the material, labor, factory overhead, and shipping costs (i.e., 25 percent of $4,795 + $1,391 + $599 + $504). Thus, in total, DOE estimates this 300kVA three-phase transformer to have a manufacturer selling price of $9,033.

In the NOPR, DOE also included new markups based on negotiator feedback. DOE increased mitering costs for both low and medium voltage dry-type transformers based on negotiation feedback. In low-voltage units, DOE modeled butt-lapped designs at the baseline efficiency level whereas ordinary mitering was modeled at the baseline for medium-voltage, therefore DOE used different processing adders for low-voltage and medium voltage. For medium-voltage transformers, DOE included a 10 cents per core pound processing cost for step-lap mitering. In the low-voltage case, DOE incorporated a processing cost of 10 cents per core pound for ordinary mitering and 20 cents per core pound for step-lap mitering.

5.4.1 Material Prices

DOE used prices of core steel, conductor, mineral oil, insulation, and other materials as an input to the transformer design software used for the engineering analysis. As the price of one material increases or decreases relative to the other materials, the software will modify its design and increase or decrease the amount of that material while balancing other design parameters, creating a cost-optimized transformer. Material pricing is also critical because the manufacturer's selling prices calculated in the engineering analysis are based on a bill of materials that includes, for example, specifications for pounds of steel, pounds of conductor, gallons of mineral oil, and tank dimensions. Therefore, as material prices increase, so will the manufacturer's selling price. Furthermore, as discussed in chapter 3, energy-efficient transformers tend to incorporate more materials (e.g., pounds of core steel, pounds of conductor), making the impact of more expensive materials even more significant at higher efficiencies.

DOE contracted OPS to develop material price estimates for the engineering analysis. OPS used data from their own records as well as data provided by transformer manufacturers and material suppliers and wholesalers. Although not all transformer manufacturers pay the same amount per pound for electrical-grade steels, due to varied contract negotiations, these prices are intended to be representative of a standard quantity order for a medium- to large-scale U.S. transformer manufacturer.

DOE supplemented that price data by aggregating information obtained during interviews with manufacturers of distribution transformers. After the preliminary analysis, DOE received feedback that volatility in the conductor commodities markets made it difficult to consider any price accurate for any length of time because the rate of price movement was high relative to typical purchase contract terms.

DOE received feedback that it could develop conductor prices by establishing a processing "adder," or a cost required to form the finished good from the underlying commodity. The adder would change much more slowly than the price of the processed commodity and would allow DOE to derive conductor prices by summing the processing adder and the price of the underlying commodity obtained from exchanges such as COMEX and London Metal Exchange (LME). DOE intends to continue deriving conductor prices in this manner in future updates to the analysis. For the NOPR, DOE used this approach.

DOE conducted the engineering analysis using material prices over a five-year time period from 2006-2010, all in constant 2010$. Using the material prices from this time period, DOE considered a current (2010) material price, a minimum price (based on 2006 prices), and a maximum price (based on 2008 prices) for its analysis. This was done to account for variation in pricing for the different materials, which could have a significant impact on the total cost of the distribution transformer. All transformer designs that were newly optimized used the current 2010 material price, which DOE used as one of its reference cases. The maximum and minimum prices were then applied to these same designs to generate a manufacturer selling price for each of those scenarios. The results of the current 2010 material prices are presented here in chapter 5, while the results of the minimum and maximum material prices are presented in Appendix 5C.

Based on discussions in negotiations, DOE decided to implement a second reference case, using 2011 material prices. The 2011 steel prices were developed using manufacturer feedback gathered in interviews and during the negotiation process. Relative to the 2010 prices, 2011 steel prices were lower, particularly for M2 grade steel and worse. Results from the 2011 price trend are also presented here in chapter 5.

DOE noted that the price of the most critical material input to a distribution transformer, electrical core steel, had varied significantly for some M-grades over the five-year time horizon. For this reason, DOE researched the grain-oriented electrical steel market to gain a better understanding of the main players and some of the factors influencing these price fluctuations (see Appendix 3A).

In the LCC analysis (chapter 8), DOE presents results on its sensitivity analyses conducted on various LCC inputs, which included material prices. In chapter 8, the 2008 + 25% material price scenario is referred to as the "high" price scenario, the 2010 price scenario is called the "medium" price scenario, and the 2006 – 25% material price scenario is referred to as the "low" price scenario. DOE chose to utilize the current 2010 material price in the reference case after receiving feedback from transformer manufacturers and suppliers of core steel indicating that current prices would be a better price indicator than a five-year average price. These material prices can be found in the material price tables presented in this section. The resulting manufacturer selling prices are provided in the LCC and engineering spreadsheets.

5.4.2 Material Price Inputs to the Design Software – Liquid-Immersed

Table 5.4.1 presents the material prices for a typical manufacturer of liquid-immersed transformers. All designs were optimized on a set of 2010 prices. After optimization, slight adjustments were made to 2010 prices, and a 2011 price scenario was developed. Both of thes reference scenarios are present along with a minimum and maximum price scenario.

Table 5.4.1 Typical Manufacturer's Material Prices for Liquid-Immersed Design Lines

Item and Description	2010 Price	2011 Price	Min Price (2006 - 25%)	Max Price (2008 + 25%)
M6 core steel	1.33	1.04	0.94	2.19
M5 core steel	1.38	1.10	0.99	2.24
M4 core steel	1.45	1.20	1.03	2.30
M3 core steel	1.88	1.30	1.06	2.60
M3 Lite Carlite core steel	1.95	1.95	1.47	2.44
M2 core steel	2.00	1.40	1.32	2.79
M2 Lite Carlite core steel	2.10	2.10	1.58	2.63
ZDMH (mechanically-scribed core steel)	2.05	1.90	1.41	3.22
SA1 (amorphous) - finished core, volume production	2.38	2.20	1.72	3.64
Copper wire, formvar, round #10-20	4.87	4.87	3.33	5.97
Copper wire, enameled, round #7-10	4.84	4.84	3.31	5.93
Copper wire, enameled, rectangular sizes	4.97	4.97	3.41	6.09
Aluminum wire, formvar, round #9-17	3.07	3.07	2.30	3.91
Aluminum wire, formvar, round #7-10	2.57	2.57	1.93	3.28
Copper strip, thickness range 0.02-0.045	4.97	4.97	3.41	6.09
Copper strip, thickness range 0.030-0.060	4.97	4.97	3.41	6.09
Aluminum strip, thickness range 0.02-0.045	2.08	2.08	1.56	2.67
Aluminum strip, thickness range 0.045-0.080	2.08	2.08	1.56	2.67
Kraft insulating paper with diamond adhesive	1.52	1.52	1.17	1.93
Mineral oil	3.35	3.35	1.94	3.84
Tank Steel	0.38	0.38	0.32	0.60

The price used for a prefabricated amorphous core is based on prices of finished cores from North American manufacturers. In the previous rulemaking for distribution transformers, DOE analyzed the cost of importing finished cores from overseas. Since that time, several North American core manufacturers have begun producing amorphous cores. For the preliminary analysis and NOPR, DOE considered the price of a prefabricated amorphous core bought from a North American core manufacturer.

In addition to the aforementioned materials that vary during the design optimization process (e.g., core steel, windings, insulation), there are other direct materials inputs that are fixed costs and generally do not influence the design or vary with efficiency rating. These include direct materials, such as the high- and low-voltage bushings and the core clamps. DOE also prepared estimates of the tank fabrication cost, based on the optimized transformer design (the software considers this variable) and the labor necessary to build the tank. Table 5.4.2 summarizes all the estimated fixed material costs and estimates of the tank costs for each of the five liquid-immersed design lines.

For DL1, a 50kVA single-phase pad-mounted unit, the high-voltage bushings are two universal bushing wells, 15 kV, 95 BIL, 14400V, costing $14 each. The low-voltage bushings are three threaded copper studs, 240/120V, 50 kVA, costing $30 for the set. Internal hardware costs include a core clamp, nameplate, and other miscellaneous hardware costing $41.65. The finished tank size (and associated cost) varies by design, but the average cost is approximately $143.

For DL2, a 25kVA single-phase pole-mounted unit, the high-voltage terminal is a single, wet-process porcelain bushing assembly, 15 kV, 125 BIL, costing $6. The low-voltage terminals are three molded polymer bushings, 120/240V, 25 kVA, costing $8 for the set. Internal hardware costs include a core clamp, nameplate, and other miscellaneous hardware, costing $19.15. The finished tank sizes (height and diameter) vary by design, but the average cost is approximately $73.

For DL3, a 500kVA single-phase unit, the high-voltage connector is a single, wet-process porcelain bushing, 25 kV, 125 BIL, costing $6. The low-voltage bushings are two four-hole "J" Spade 500kVA, 277V, costing $60 for the set. The internal hardware includes a core clamp ($30), nameplate ($0.65), and miscellaneous hardware ($20), totaling $50.65. The design software optimized the tank cost with each design, including radiators (external cooling) for this kVA rating. The resultant finished round tank has a diameter of 33" to 52", with an average cost of approximately $629 (including radiators).

For DL4, a 150kVA three-phase, pad-mounted unit, the high-voltage bushings are three externally clamped, universal high-voltage bushing wells, 8.3/14.4 kV, 95 BIL, costing $7 each. The low-voltage bushings are three copper studs at $8 each. The internal hardware includes core clamps ($30), nameplate ($0.65), and miscellaneous hardware ($45), totaling $75.65. The optimized finished tank sizes measure 50 inches high and vary in width and depth. The finished rectangular, welded tank has an average cost of approximately $389.

For DL5, a 1500kVA three-phase, pad-mounted unit, the high-voltage bushings are three externally clamped, universal high-voltage bushing wells, 15.2/26.3 kV, 125kV BIL, costing $20 each. The low-voltage bushings are four externally clamped bushings, each having six-hole spade, costing $160 for the set. The internal hardware includes core clamps ($60), nameplate ($0.65), and miscellaneous hardware ($45), totaling $105.65. The optimized finished tank sizes measure 70 inches high and vary in width and depth. The finished rectangular, welded tank, including radiators as specified by the design software, has an average cost of approximately $1,016.

Table 5.4.2 Summary Table of Fixed Material Costs for Liquid-Immersed Units

Item	**DL1**	**DL2**	**DL3**	**DL4**	**DL5**
High voltage bushings	$28	$6	$6	$21	$60
Low voltage bushings	$30	$8	$60	$24	$160
Core clamp, nameplate, and misc. hardware	$41.65	$19.15	$50.65	$75.65	$105.65
Transformer tank average cost*	~$143	~$73	~$629	~$389	~$1,016

* Transformer tank steel is used in the design optimization software and varies with the efficiency (and size) of each design. DL3 and DL5 include calculated costs of radiators, which are scaled for each design based on the required cooling surface area.

5.4.3 Material Price Inputs to the Design Software – Dry-Type

Table 5.4.3 presents the material prices for a typical dry-type transformer manufacturer indicating the reference cases (2010 and 2011 prices), minimum (2006), and maximum (2008) prices (all in constant 2010$).

Table 5.4.3 Manufacturer's Material Prices for Dry-Type Design Lines

Item and Description	2010 Price	2011 Price	Min Price (2006 - 25%)	Max Price (2008 + 25%)
M36 core steel (26 gauge)	0.60	0.66	0.46	0.84
M19 core steel (26 gauge)	0.83	0.91	0.56	1.19
M12 core steel	0.95	0.78	0.85	1.60
M6 core steel	1.33	1.04	0.94	2.19
M5 core steel	1.38	1.10	0.99	2.24
M4 core steel	1.45	1.20	1.03	2.30
M3 core steel	1.88	1.30	1.06	2.60
M2 core steel	2.00	1.40	1.32	2.79
H-0 DR core steel (laser-scribed)	2.06	1.70	1.41	3.23
SA1 (amorphous) - finished core, volume production	2.38	2.20	1.72	3.64
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped	4.52	4.52	3.07	5.53
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped	2.97	2.97	2.23	3.78
Copper strip, thickness range 0.02-0.045	4.97	4.97	3.41	6.09
Aluminum strip, thickness range 0.02-0.045	2.08	2.08	1.56	2.67
Nomex insulation (per pound)	24.50	24.50	13.72	29.03
Cequin insulation (per pound)	5.53	5.53	3.84	6.09
Impregnation (per gallon)	22.55	22.55	17.16	27.31
Winding Combs (per pound)	12.34	12.34	6.08	15.41
Enclosure Steel (per pound)	0.38	0.38	0.32	0.60

As stated in section 5.3, the OPS software does not take into account retooling costs associated with changing production designs. Therefore, to partially capture these differential costs in the design lines that had both buttlap and mitered designs, DOE used adders in DL7 and DL8. The adders specified an extra 10 cents per pound of core steel for full-mitered designs. More detailed costing of the retooling costs for mitering equipment will be covered in the manufacturer impact analysis (MIA). (See chapter 12.)

Similar to the liquid-immersed designs, there are fixed (and some partially variable) hardware costs associated with dry-type distribution transformers. These are discussed individually and then summarized in Table 5.4.4.

For DL6, a 25 kVA single-phase, low-voltage, dry-type transformer, the low-voltage and high-voltage terminal set costs $4. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $9.25. The fiberglass dog-bone duct-spacers used for this design line cost $0.24 per foot. DOE estimated the miscellaneous hardware costs at

$4.50. The ventilated enclosure – a 16-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 25kVA unit, and costs approximately $50.

For DL7, a 75 kVA three-phase, low-voltage, dry-type transformer, the fixed hardware costs are $9 per phase for the high-voltage terminal board with connection points. DOE estimated the secondary (low-voltage) bus-bar to be seven feet at $1.50 per foot, or $10.50. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $19. The fiberglass dog-bone duct-spacers used for this design line cost $0.32 per foot. DOE estimated the miscellaneous hardware costs at $7. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 75kVA unit, and costs approximately $90.

For DL8, a 300 kVA three-phase, low-voltage, dry-type transformer, the high-voltage terminal board costs $27. DOE estimated the secondary (low-voltage) bus-bar to be nine feet at $2.50 per foot, or $22.50. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $36. The fiberglass dog-bone duct-spacers used for this design line cost $0.42 per foot. DOE estimated the miscellaneous hardware costs at $12. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 300kVA unit, and costs approximately $100.

For DL9, a 300 kVA three-phase, medium-voltage, dry-type transformer at 45 kV BIL, the low-voltage and high-voltage terminal set costs $75. DOE estimated the secondary (low-voltage) bus-bar to be eight feet at $10 per foot, or $80. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $36. The fiberglass dog-bone duct-spacers used for this design line cost $0.42 per foot. DOE estimated the miscellaneous hardware costs at $25. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 300 kVA unit, and costs approximately $135.

For DL10, a 1500 kVA three-phase, medium-voltage, dry-type transformer at 45 kV BIL, the low-voltage and high-voltage terminal set costs $120. DOE estimated the low-voltage bus-bar to be 14 feet at $10 per foot, or $140. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $120. DOE accounted for the cost of additional bracing in the amorphous design since the amorphous design uses a wound core rather than a round, cruciform core like the other designs. This extra bracing is needed for the amorphous design due to the size of DL10 (1500 kVA). The weight of the added bracing was calculated as 7 percent of the core and coil weight, and was multiplied by the price for enclosure steel to derive a cost. The bracing weighs 600 pounds on average and costs approximately $230. The fiberglass dog-bone duct-spacers used for this design line cost $0.52 per foot. DOE estimated the miscellaneous hardware costs at $42. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 1500 kVA unit, and costs approximately $400.

For DL11, a 300 kVA three-phase, medium-voltage, dry-type at 95 kV BIL, the low-voltage and high-voltage terminal set costs $100. The high-voltage terminal boards cost $27. DOE estimated the low-voltage bus-bar is estimated to be 10 feet at $8 per foot, or $80. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $42. The fiberglass dog-bone duct-spacers used for this design line cost $0.42 per foot. DOE estimated the miscellaneous hardware costs at $32. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 300 kVA unit, and costs approximately $200.

For DL12, a 1500 kVA three-phase, medium-voltage, dry-type at 95 kV BIL, the low-voltage and high-voltage terminal set costs $135. The high-voltage terminal boards cost $27. DOE estimated the low-voltage bus-bar is estimated to be 16 feet at $12 per foot, or $192. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $125. DOE accounted for the cost of additional bracing in the amorphous design since the amorphous design uses a wound core rather than a round, cruciform core like the other designs. This extra bracing is needed for the amorphous design due to the size of DL12 (1500 kVA). The weight of the added bracing was calculated as 7 percent of the core and coil weight, and was multiplied by the price for enclosure steel to derive a cost. The added bracing weighs 700 pounds on average and costs approximately $270. The fiberglass dog-bone duct-spacers used for this design line cost $0.56 per foot. DOE estimated the miscellaneous hardware costs at $54. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 1500 kVA unit, and costs approximately $450.

For DL13A, a 300 kVA three-phase, medium-voltage, dry-type at 125 kV BIL, the low-voltage and high-voltage terminal set costs $115. The high-voltage terminal boards cost $27. DOE estimated the low-voltage bus-bar is estimated to be 10 feet at $10 per foot, or $100. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $50. The fiberglass dog-bone duct-spacers used for this design line cost $0.42 per foot. DOE estimated the miscellaneous hardware costs at $36. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 300 kVA unit, and costs approximately $200.

For DL13B, a 2000 kVA three-phase, medium-voltage, dry-type at 125 kV BIL, the low-voltage and high-voltage terminal set costs $150. The high-voltage terminal boards cost $27. DOE estimated the low-voltage bus-bar is estimated to be 18 feet at $15 per foot, or $270. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $175. DOE accounted for the cost of additional bracing in the amorphous design since the amorphous design uses a wound core rather than a round, cruciform core like the other designs. This extra bracing is needed for the amorphous design due to the size of DL13B (2000 kVA). The weight of the added bracing was calculated as 7 percent of the core and coil weight, and was multiplied by the price for enclosure steel to derive a cost. The added bracing weighs 850 pounds on average and costs approximately $330. The fiberglass dog-bone duct-spacers used for this design line cost $0.60 per foot. DOE estimated the miscellaneous hardware costs at $60. The ventilated enclosure – a 14-gauge steel enclosure, base, and mounting feet – varies with the size of the core-coil assembly for the 300 kVA unit, and costs approximately $450.

Table 5.4.4 Summary Table of Fixed Material Costs for Dry-Type Units

Item	DL6	DL7	DL8	DL9	DL10	DL11	DL12	DL13A	DL13B
LV and HV terminals (set)	$4	n/a	n/a	$75	$120	$100	$135	$115	$150
HV terminal board(s)	n/a	$27	$27	$27	$27	$27	$27	$27	$27
LV bus-bar	n/a	$10.50	$22.50	$80	$140	$80	$192	$100	$270
Core/coil mounting frame	$9.25	$19	$36	$36	$120	$42	$125	$50	$175
Additional Bracing	n/a	n/a	n/a	n/a	~$230	n/a	~$270	n/a	~$330
Nameplate	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65	$0.65
Dog-bone duct spacer (ft.)	$0.24	$0.32	$0.42	$0.42	$0.52	$0.42	$0.56	$0.42	$0.60
Winding combs (lb.)	n/a	n/a	n/a	n/a	n/a	$10.00	$10.00	$10.00	$10.00
Misc. hardware	$4.50	$7	$12	$25	$42	$32	$54	$36	$60
Enclosure (12, 14 gauge)	~$50	~$90	~$100	~$135	~$400	~$200	~$450	~$200	~$450

LV = low voltage
HV = high voltage

5.4.4 Labor Costs

Labor costs are a critical aspect of the cost of manufacturing a distribution transformer. DOE used the same hourly labor cost for both liquid and dry-type distribution transformers. It developed the hourly cost of labor using a similar approach to the development of the cost of materials; however, it used different markups. DOE developed the markups shown in Table 5.5 after reviewing publicly available information, speaking with transformer manufacturers during 2011, and consulting with industry experts familiar with transformer manufacturing in the U.S.

Table 5.5 Labor Markups for Liquid-Immersed and Dry-Type Manufacturers

Item description	Markup percentage	Rate per hour
Labor cost per hour*		$ 16.80
Indirect Production**	33%	$ 22.35
Overhead***	30%	$ 29.05
Fringe†	24%	$ 36.03
Assembly Labor Up-time††	43%	**$** 51.52
Fully-Burdened Cost of Labor	25%	$ **64.40**

* Cost per hour is from U.S. Census Bureau, *2007 Economic Census - Detailed Statistics*, published October 2009. Data for NAICS code 3353111 "Power and distribution transformers, except parts" Production workers hours and wages.
** Indirect production labor (e.g., production managers, quality control) as a percent of direct labor on a cost basis. Navigant Consulting, Inc. (NCI) estimate.
*** Overhead includes commissions, dismissal pay, bonuses, vacation, sick leave, and social security contributions. NCI estimate.
† Fringe includes pension contributions, group insurance premiums, workers compensation. Source: U.S. Census Bureau, *2007 Economic Census - Detailed Statistics*, published October 2009. Data for NAICS code 3353111 "Power and distribution transformers, except parts" Total fringe benefits as a percent of total compensation for all employees (not just production workers).
†† Assembly labor up-time is a factor applied to account for the time that workers are not assembling units and/or reworking unsatisfactory units. The markup of 43 percent represents a 70 percent utilization (multiplying by 100/70). NCI estimate.

5.4.4.1 Liquid-Immersed Labor Hours

There are several labor steps involved in manufacturing a liquid-immersed transformer. DOE prepared estimates of the amount of labor involved, some varying with the transformer design and others fixed on a per-unit basis. These steps are described below, and the amount of time dedicated to each is given in Table 5.6.

- Cutting, Forming, and Annealing – This task involves cutting the core steel to lengths on a distributed-gap core cutting machine, forming the resulting “donut” of core steel into a rectangular shape in a hydraulic press, and then annealing the core in a high temperature annealing furnace. DOE calculated the labor involved in these activities based on the weight of core (pounds) multiplied by a constant, which varies with the lamination thickness of the core steel. For DL1, DL2, and DL4, on M6 designs the constant is 0.08, M5 is 0.09, M4 is 0.10, M3 (with or without Lite Carlite) and ZDMH are 0.125, and M2 (with or without Lite Carlite) is 0.16. For DL3 and DL5, on M6 designs the constant is 0.05, M5 is 0.06, M4 is 0.07, M3 (with or without Lite Carlite) and ZDMH are 0.09, and M2 (with or without Lite Carlite) is 0.11. For the prefabricated core — SA1 (amorphous material)—DOE set the labor for cutting, forming, and annealing to zero.

- Primary Winding – This task entails winding the primary conductor of the transformer. It includes set-up time as well as winding time. The labor hours vary with the number of turns (per phase) for the primary winding. For DL1, DL2, and DL4, the winding time is

0.0001 hours per turn. For these smaller kVA ratings (and smaller cores), this rate is very low because some of the larger, liquid-immersed manufacturers wind multiple coils simultaneously on the same winding machine. This manufacturing approach improves throughput and productivity at the facility. The rate of 0.0001 hours per turn equates to approximately one-third of a second per turn. On DL3 and DL5, due to the larger coil size associated with these units, the winding time is 0.002 hours per turn (approximately 7.2 seconds per turn).

- Secondary Winding – This task involves winding the secondary conductor of the transformer. It includes set-up time as well as winding time. On a distribution (step-down) transformer, the number of secondary turns is always less than the primary. For the liquid-immersed units, which are taking a relatively high primary voltage and dropping to below 600V, the turns ratio can be as large as 100:1. For this reason, the hours per turn of the secondary are considerably higher than the primary, because there are fewer turns over which to amortize the set-up time as well as a slower winding rate for the secondary, which has larger cross-sectional area than the primary. For DL1, DL2, and DL4, the hours per turn of the secondary are 0.015 (54 seconds per turn); for DL3 and DL5, the hours per turn are 0.02 (72 seconds per turn).

- Lead Dressing – Once a wound coil is taken off the winding machine, work must be performed on the leads to prepare them for the next manufacturing step. Enamel is removed to enable good electrical connection and insulating tubing is slipped over the cable. This is a fixed amount of labor, and does not vary with efficiency or design. Lead dressing time ranges from 0.1 to 1 hour.

- Coil Varnishing and Baking – Once they are complete, the coils are vacuum-dipped in varnish and baked in an oven to cure the varnish and enhance the integrity of the coil. This task varies slightly with kVA rating, but does not vary with efficiency. The estimated times range from 0.07 to 0.25 hours.

- Core Assembly ("Lacing") – This task involves assembling and banding the annealed wound core laminations around varnished windings. The annealed bundle of core steel is disassembled from the inside out by grabbing approximately 1/4 inch bundles, then reassembling the core steel around the coils. Once all the laminations are reassembled, the core material is clamped to maintain the structure. The activity involves feeding a banding strip around the core material and using a locking clamp to compress and contain the core material. The labor rate varies with stack height and lamination thickness for each design. The average time for core assembly ranges from approximately 0.2 hours (for DL2) to 4.9 hours (for DL5).

- Tanking and Impregnating – This task involves inserting and fastening the core/coil assembly into the tank. Then, a vacuum is pulled and oil is introduced to the tank. On round tanks, the vacuum and oil step is done through a lid attached to the top of the unit. On the rectangular and pad-mounted tanks, the vacuum is pulled in a chamber, which takes a little longer per unit. Finally, tap changers and bushings are mounted, and bolted connections made. The time for this activity does not vary with design or efficiency, but it does vary by kVA rating and tank shape. The estimates of labor time for the five liquid-immersed design lines range from 0.1 to 1.8 hours.

- Inspection – This activity involves verifying that the transformer is assembled properly and is up to a manufacturer's quality specification. This task includes inspecting the lead dressing, lead tie-up, and other quality certification specifications. The time for this activity does not vary with design or efficiency, but it does vary by kVA rating, from 0.05 hours for the smallest units to 0.20 hours for the largest units.

- Preliminary Test – This step involves conducting a test to ensure that the core/coil meets the specified turns ratio, polarity, core loss, etc. . The time for this activity does not vary with design or efficiency, but it does vary by kVA rating from 0.05 to 0.15 hours.

- Final Test – This activity involves testing of the final, assembled unit, with the core/coil assembly immersed in oil. This test verifies that the unit meets the guaranteed values, including core and coil losses, impedance, and dielectric tests. The time for this activity does not vary with design or efficiency, but it does vary by kVA rating from 0.1 to 0.25 hours.

- Pallet Loading – This activity involves preparing the transformer for shipping to the customer. This includes loading the finished transformer onto a pallet, banding the transformer to the pallet, wrapping, and all other necessary steps for shipping. The time for this activity does not vary with design or efficiency, but it does vary by kVA rating from 0.15 hours for the smallest units to 3 hours for the largest units.

- Marking and Miscellaneous – This task involves preparing any extra markings around the bushings or on the surface of the transformer and other miscellaneous labor associated with preparing the finished transformer for the customer. The time for this activity does not vary with design or efficiency, but it does vary by kVA rating from 0.08 to 0.35 hours.

Table 5.6 summarizes the estimates of labor time that DOE used for the five liquid-immersed units.

Table 5.6 Summary of Labor Times for Liquid-Immersed Units

Labor Activity	**DL1** ***hrs.***	**DL2** ***hrs.***	**DL3** ***hrs.***	**DL4** ***hrs.***	**DL5** ***hrs.***
Cutting, Forming, & Annealing	~1.00	~0.75	~4.00	~3.00	~8.50
Primary Winding (hrs/turn)	0.0001	0.0001	0.002	0.0001	0.002
Secondary Winding (hrs/turn)	0.015	0.015	0.020	0.015	0.020
Lead Dressing	0.50	0.1	0.35	0.75	1.00
Baking Coils	0.10	0.07	0.15	0.17	0.25
Core Assembly	~0.40	~0.20	~1.20	~1.00	~4.90
Tanking and Impregnating	0.30	0.11	0.65	0.50	1.80
Inspection	0.10	0.05	0.10	0.15	0.20
Preliminary Test	0.10	0.05	0.10	0.10	0.15
Final Test	0.15	0.1	0.15	0.20	0.25
Pallet Loading	0.5	0.15	0.75	0.50	3.00
Marking and Misc.	0.35	0.08	0.35	0.35	0.75

5.4.4.2 Dry-Type Labor Hours

Likewise, there are several labor steps involved in manufacturing a dry-type transformer. For the preliminary analysis, DOE prepared estimates of the amount of labor involved, some varying with the transformer design and others fixed on a per-unit basis. . For the NOPR analysis DOE modified its approach based on comments in negotiations, and calculated a core labor estimate based on the weight of the transformer. . In addition, DOE prepared a constant labor hour value for all other labor steps involved. . This value was held constant for all designs within a design line and was prepared based on data and feedback from manufacturers in negotiations. These steps are described below.

- Core Stacking – This task involves stacking (assembling) the cut steel laminations into a distribution transformer core. The amount of labor for this task varies by kVA rating, stack height, and whether the core is grain-oriented or non-oriented. Thus, the labor for core stacking varies with the efficiency of the transformer.

- Primary Winding – This task encompasses winding the primary conductor of the transformer. It includes set-up time as well as winding time.

- Secondary Winding – This task involves winding the secondary conductor of the transformer. It includes set-up time as well as winding time. The winding time of the secondary is considerably higher than that of the primary, because there are fewer turns over which to amortize the set-up time as well as a slower winding rate for the secondary, which has larger cross sectional area.

- Lead Dressing – Once a wound coil is taken off the winding machine, work must be performed on the leads to prepare them for the next manufacturing step. Enamel is removed to enable good electrical connection and insulating tubing is slipped over the cable.

- Assembly – This task involves installing the wound coils onto the partially assembled core, and then lacing the top (yoke) laminations to complete the core. It also includes setting all the core clamps and completing the core/coil assembly. DOE assumed the assembly time varies by kVA rating, but does not vary by design within a kVA rating.

- Inspection – This activity involves verifying that the transformer is assembled properly and is up to a manufacturer's quality specification. It includes inspecting the lead dressing, lead tie up, and other quality certification specifications.

- Preliminary Test – This step involves conducting a test to ensure that the core/coil meets the specified turns ratio, polarity, core loss, etc. .

- Final Test – This activity involves testing the final, assembled unit, with the core/coil assembly immersed in oil. This test verifies that the unit meets the guaranteed values, including core and coil losses, impedance, and dielectric tests.

- Enclosure Manufacturing – The labor estimate for this task encompasses all activity associated with the cutting, forming, assembly, priming, painting, and preparation of the enclosure.

- Packing – This activity involves preparing the transformer for shipping to the customer. This includes loading the finished transformer onto a pallet, banding the transformer to the pallet, wrapping, and all other necessary steps for shipping.

- Marking and Miscellaneous – This task involves preparing any extra markings on the terminal board or on the surface of the transformer, and other miscellaneous labor associated with preparing the finished transformer for the customer.

During negotiations, DOE learned that mitering, particularly step-lap mitering, results in a higher cost per pound of core steel than butt-lapping. . In response, DOE incorporated a processing adder for mitered designs for both low- and medium-voltage dry-type designs. . In the medium-voltage case, DOE incorporated a processing adder of 10 cents per pound for step-lap mitering. . In the low-voltage case, DOE incorporated a processing cost of 10 cents per pound for ordinary mitering and 20 cents per pound for step-lap mitering. . Different processing adders were used for low-voltage and medium-voltage to account for the fact that the base case design option is different. . In low-voltage units, DOE modeled butt-lapped designs at the baseline efficiency level whereas ordinary mitering was modeled at the baseline for medium-voltage. . These changes were applied to all dry-type design lines. .

5.5 EFFICIENCY LEVELS

DOE analyzed designs over a range of efficiency values for each representative unit. Within the efficiency range, DOE developed designs that approximate a continuous function of efficiency. However, DOE analyzes the incremental impacts of increased efficiency by comparing discrete efficiency benchmarks to a constant baseline efficiency. The baseline efficiency evaluated for each representative unit is the existing standard level efficiency for distribution transformers established in DOE's previous rulemaking. The incrementally higher efficiency levels are meant to characterize the cost-efficiency relationship above the baseline. These efficiency levels are ultimately used by DOE if it decides to amend the existing energy conservation standards.

5.5.1 Criteria for Developing Efficiency Levels

After the preliminary analysis, DOE developed efficiency levels for each design line. . To accomplish this, DOE first found the range of efficiencies possible for each design line, ranging from the baseline to max-tech, and selected ELs as evenly spaced as possible for each design line. . While selecting the ELs, Doe also considered the efficiency potential of non-amorphous core steels and other benchmarks such as NEMA premium levels. . As much as possible, DOE incorporated these benchmarks into their selections.

Table 5.7 presents the efficiency levels (ELs) identified for each design line in the engineering analysis. Table 5.8 presents the incremental MSP for each of the least-costly design options at each efficiency level.

5.5.2 Efficiency Levels Selected

Table 5.7 presents the efficiency levels (ELs) identified for each design line in the engineering analysis. Table 5.8 presents the incremental MSP for each of the least-costly design options at each efficiency level.

Table 5.7 Summary of Baselines and Efficiency Levels for Distribution Transformer Representative Units

Design Line	Representative Unit	Base-line	EL1	EL2	EL3	EL4	EL5	EL6	EL7
		Eff. [%]	*Eff. [%]*	*Eff. [%]*	*Eff. [%]*	*Eff. [%]*	*Eff. [%]*	*Eff. [%]*	*Eff. [%]*
1	50 kVA, 65°C, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank	99.08	99.16	99.22	99.25	99.31	99.42	99.50	99.50
2	25 kVA, 65°C, single-phase, 60Hz, 14400V primary, 120/240V secondary, round tank	98.91	99.00	99.07	99.11	99.18	99.31	99.41	99.47
3	500 kVA, 65°C, single-phase, 60Hz, 14400V primary, 277V secondary	99.42	99.48	99.51	99.54	99.57	99.61	99.69	99.73
4	150 kVA, 65°C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary	99.08	99.16	99.22	99.25	99.31	99.42	99.50	99.60
5	1500 kVA, 65°C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary	99.42	99.48	99.51	99.54	99.57	99.61	99.69	99.69
6	25 kVA, 150°C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL	98.00	98.23	98.47	98.60	98.80	98.93	99.17	99.44
7	75 kVA, 150°C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL	98.00	98.23	98.47	98.60	98.80	98.93	99.17	99.44
8	300 kVA, 150°C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL	98.60	98.80	99.02	99.14	99.25	99.32	99.44	99.58
9	300 kVA, 150°C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL	98.82	98.93	99.04	99.15	99.22	99.39	99.55	99.55
10	1500 kVA, 150°C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL	99.22	99.29	99.37	99.45	99.51	99.58	99.63	99.67
11	300 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	98.67	98.81	98.94	99.06	99.13	99.32	99.50	99.50
12	1500 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	99.12	99.21	99.30	99.39	99.46	99.53	99.59	99.63
13A	300kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	98.63	98.69	98.84	98.97	99.04	99.25	99.45	99.45
13B	2000kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	99.15	99.19	99.28	99.38	99.45	99.52	99.58	99.62

Table 5.8 Summary of Incremental Manufacturer Selling Prices Over the Baseline for Distribution Transformer Representative Units

Design Line	Representative Unit	Base-line	EL1	EL2	EL3	EL4	EL5	EL6	EL7
		$	*$*	*$*	*$*	*$*	*$*	*$*	*$*
1	50 kVA, 65°C, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank	-	170	651	794	472	923	1253	N/A
2	25 kVA, 65°C, single-phase, 60Hz, 14400V primary, 120/240V	-	216	397	215	247	487	708	1185

	secondary, round tank								
3	500 kVA, 65°C, single-phase, 60Hz, 14400V primary, 277V secondary	-	849	935	2481	1606	2131	4139	7002
4	150 kVA, 65°C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary	-	574	1328	2211	1413	1164	1893	4681
5	1500 kVA, 65°C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary	-	3472	3881	5886	6585	9350	25704	25704
6	25 kVA, 150°C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL	-	20	153	235	361	404	582	1144
7	75 kVA, 150°C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL	-	1456	655	296	519	699	904	2101
8	300 kVA, 150°C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL	-	-844	-107	1030	1937	3282	2371	7372
9	300 kVA, 150°C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL	-	-422	-406	577	1392	1933	4508	N/A
10	1500 kVA, 150°C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL	-	290	2565	7501	13638	17260	22868	N/A
11	300 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	-	-322	1245	2149	2142	4003	7952	N/A
12	1500 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	-	1426	2878	7726	9313	12199	18482	26346
13 A	300kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	-	381	1409	4592	4751	7090	13256	N/A
13 B	2000kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	-	-162	5.5.3 5848	12562	19966	27890	N/A	N/A

Note: Does not include symmetric core designs. Based on reference case traditional core designs only.

5.5.4 BusLead and Bus Loss Correction

DOE received comment during negotiations that substation-style designs common to the medium-voltage, dry-type transformer market are larger than the designs that DOE had previously modeled. and experience correspondingly larger bud and lead losses, which can force a unit to employ larger, more efficient cores and coils to overcome the added loss. bus.

DOE worked with manufacturers to explore the magnitude of this effect and made small upward adjustments to bus and lead losses of all medium-voltage, dry-type design lines. . For each design line, DOE added a constant loss value to account for lead and bus losses. . This change resulted in slightly lower efficiencies (generally close to .02%) and had the effect of nudging the entire design cloud slightly to the left. Because the cost/efficiency curve is upward-sloping, this has the effect of marginally increasing the lowest MSPs for a given efficiency even though no direct cost was added to each unit. .

5.6 RESULTS OF THE ANALYSIS ON EACH DESIGN LINE

This section provides a visual representation of the results of the engineering analysis. The scatter plots in this section show the relationship between the manufacturer's selling price and efficiency for each of the 14 design lines. Each dot on the plots represents one unique design created by the software at a given manufacturer's selling price and efficiency level. The placement of each dot (and the uniqueness of each design) is dictated by the design option combinations (core steel and windings), core shape, A/B combination, and the variable design parameters generated by the design software.

5.6.1 Traditional Core Designs for the Reference Case

The designs in this section represent the traditional core designs that DOE analyzed in the life-cycle cost and national impact analyses. In addition to the results provided in this section, DOE prepared scatter plots depicting the engineering analysis results for the 14 representative units, including watts of core and coil loss and the weight by efficiency (see Appendix 5A). For each of the 14 representative units DOE presents the results with the 2010 and 2011 steel price scenarios.

Figure 5.6.1 and Figure 5.6.2 present plots of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from DL1, a 50kVA single-phase, liquid-immersed, pad-mounted distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about these scatter plots:

- The current standard efficiency level of 99.08 percent is most cost-effectively met by designs using M3 core steel (2011 prices) or ZDMH core steel (2010 prices).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.25 percent, and can reach efficiencies of 99.50 percent.

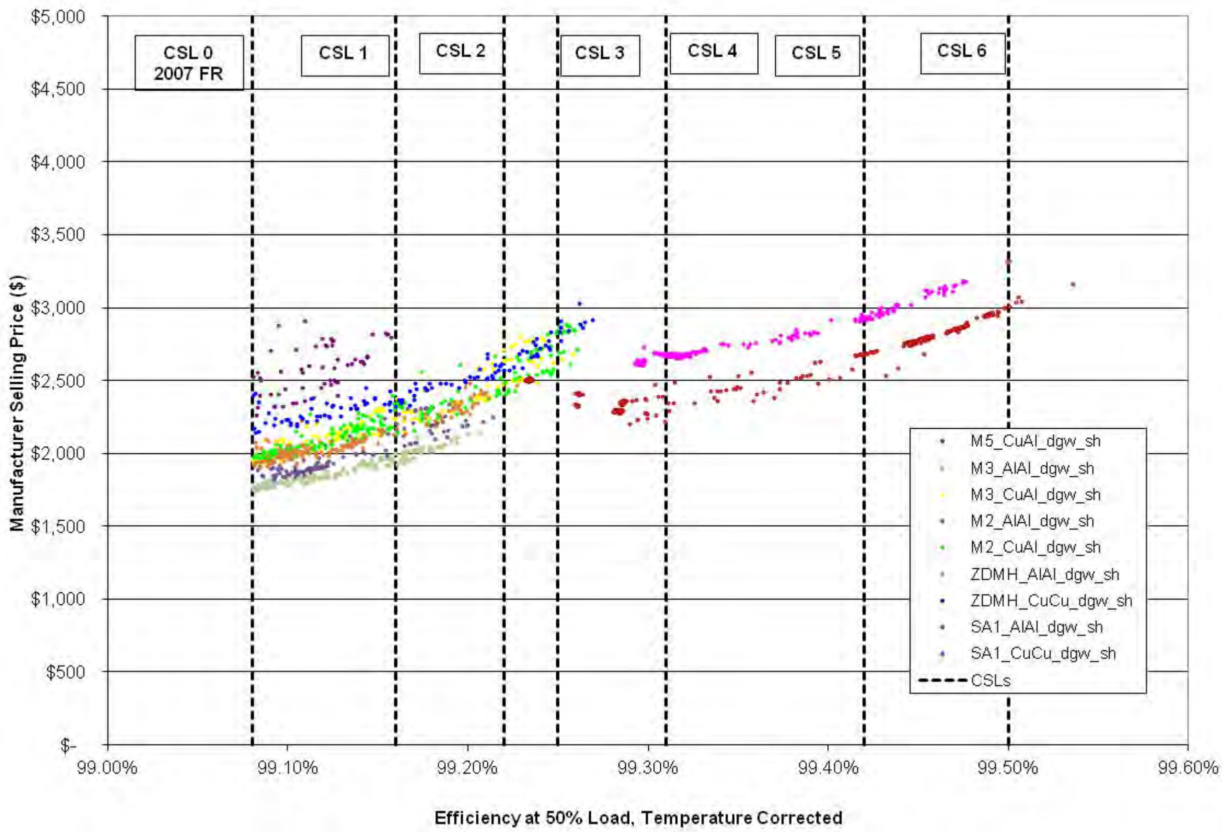

Figure 5.6.1 Engineering Analysis Results, Design Line 1, 2011

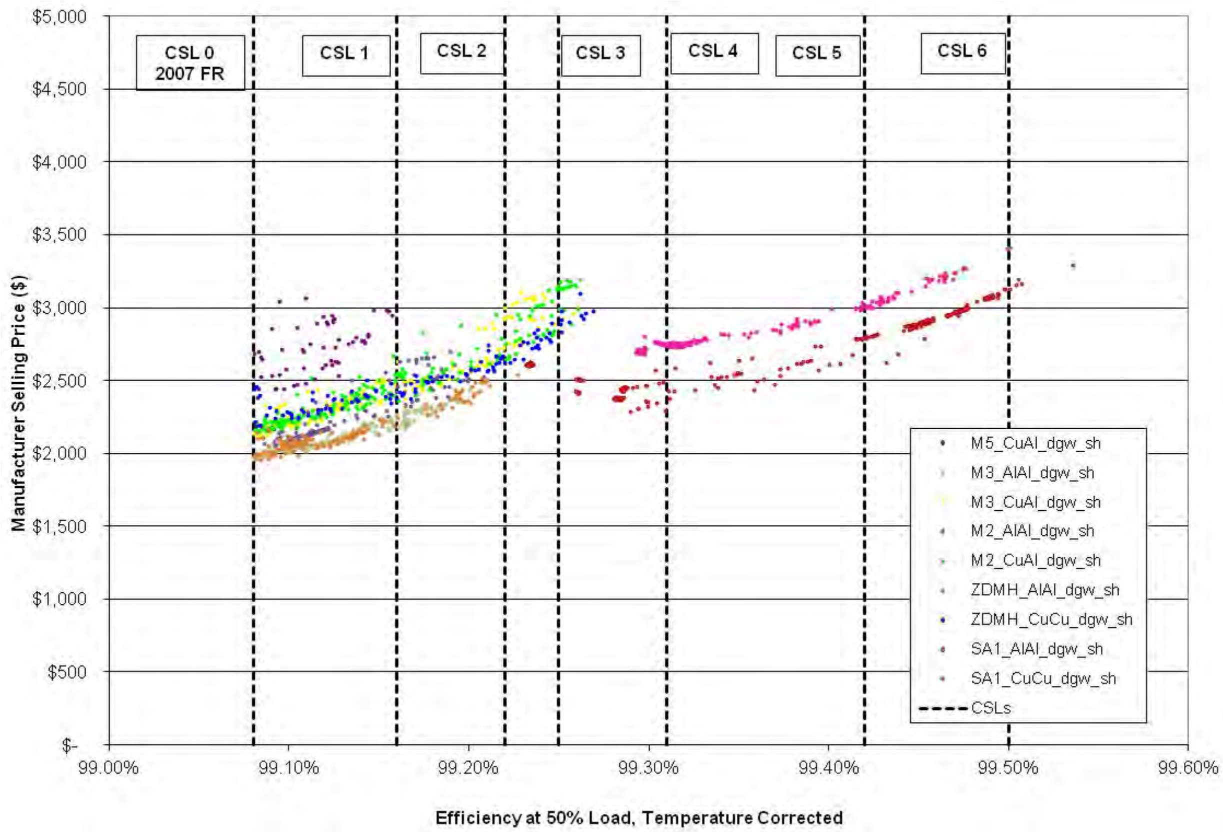

Figure 5.6.2 Engineering Analysis Results, Design Line 1, 2010

Figure 5.6.3 and Figure 5.6.4 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL2, a 25kVA single-phase, liquid-immersed, pole-mounted distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.91 percent is met most cost-effectively by designs using M2 core steel (2011 and 2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.10 percent, and can reach efficiencies up to 99.5 percent.

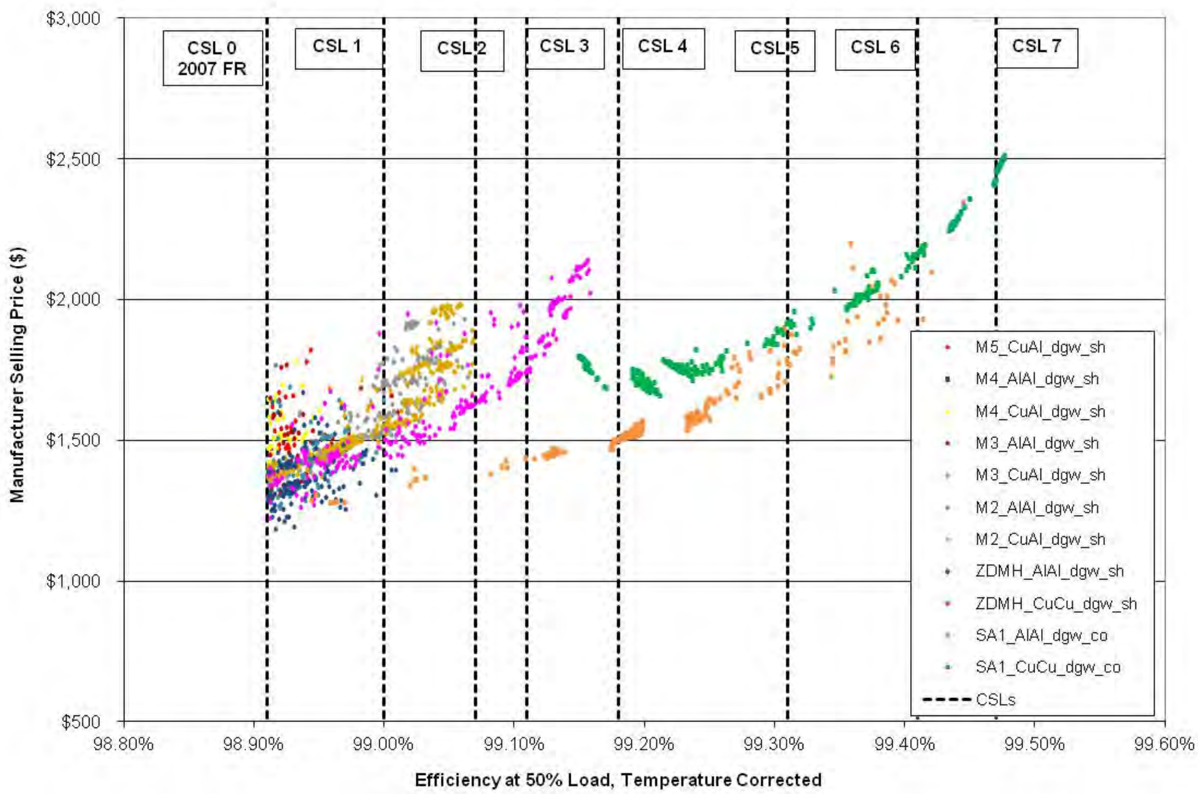

Figure 5.6.3 Engineering Analysis Results, Design Line 2, 2011

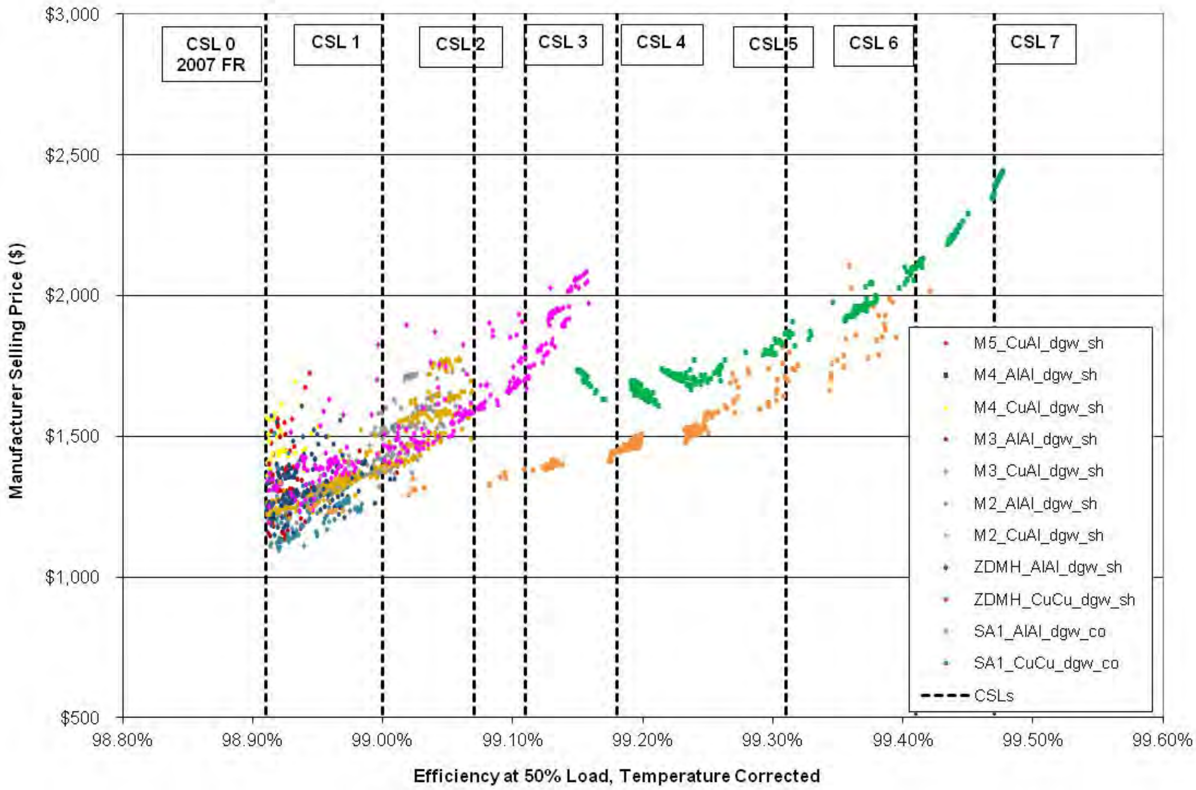

Figure 5.6.4 Engineering Analysis Results, Design Line 2, 2010

Figure 5.6.5 and Figure 5.6.6 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL3, a 500kVA single-phase, liquid-immersed distribution transformer with radiators. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.42 percent is most cost-effectively met by designs using M3 core steel (2010) or ZDMH core steel (2011).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.55 percent, and can reach efficiencies above 99.73 percent.

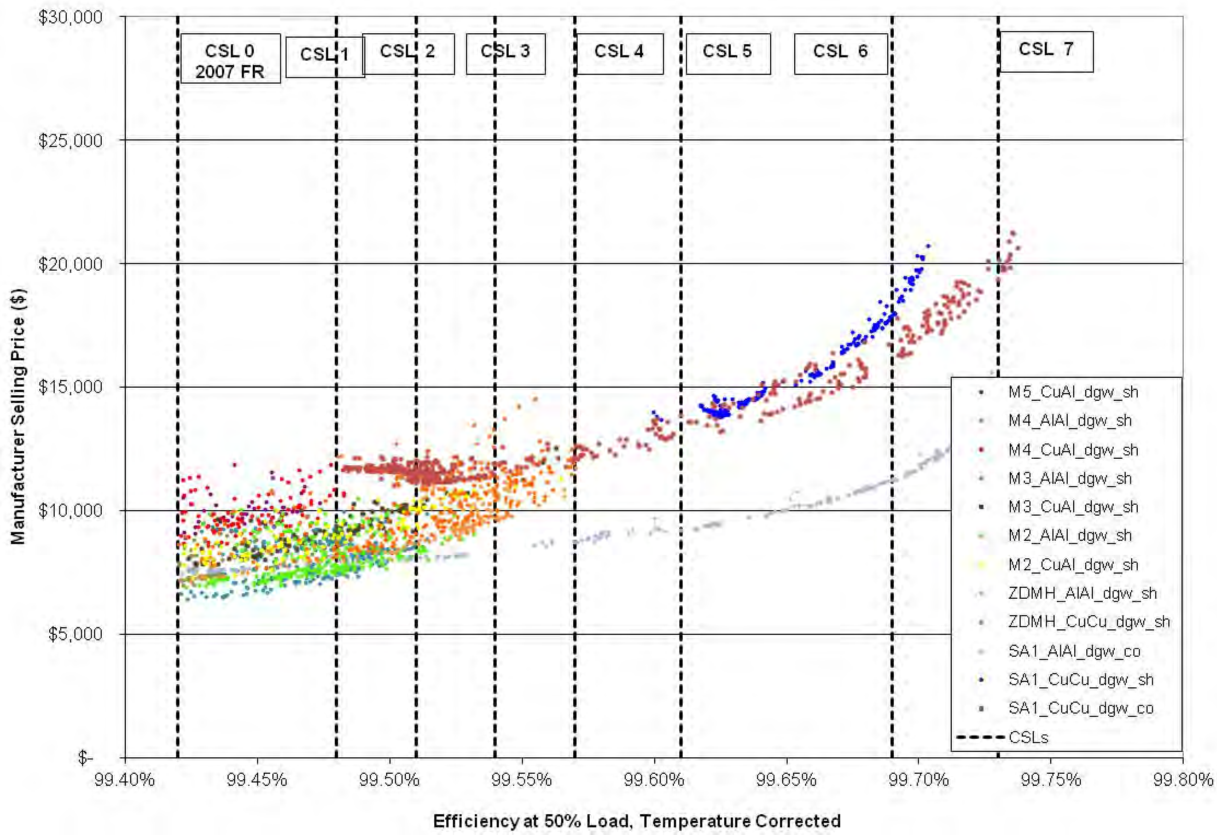

Figure 5.6.5 Engineering Analysis Results, Design Line 3, 2011

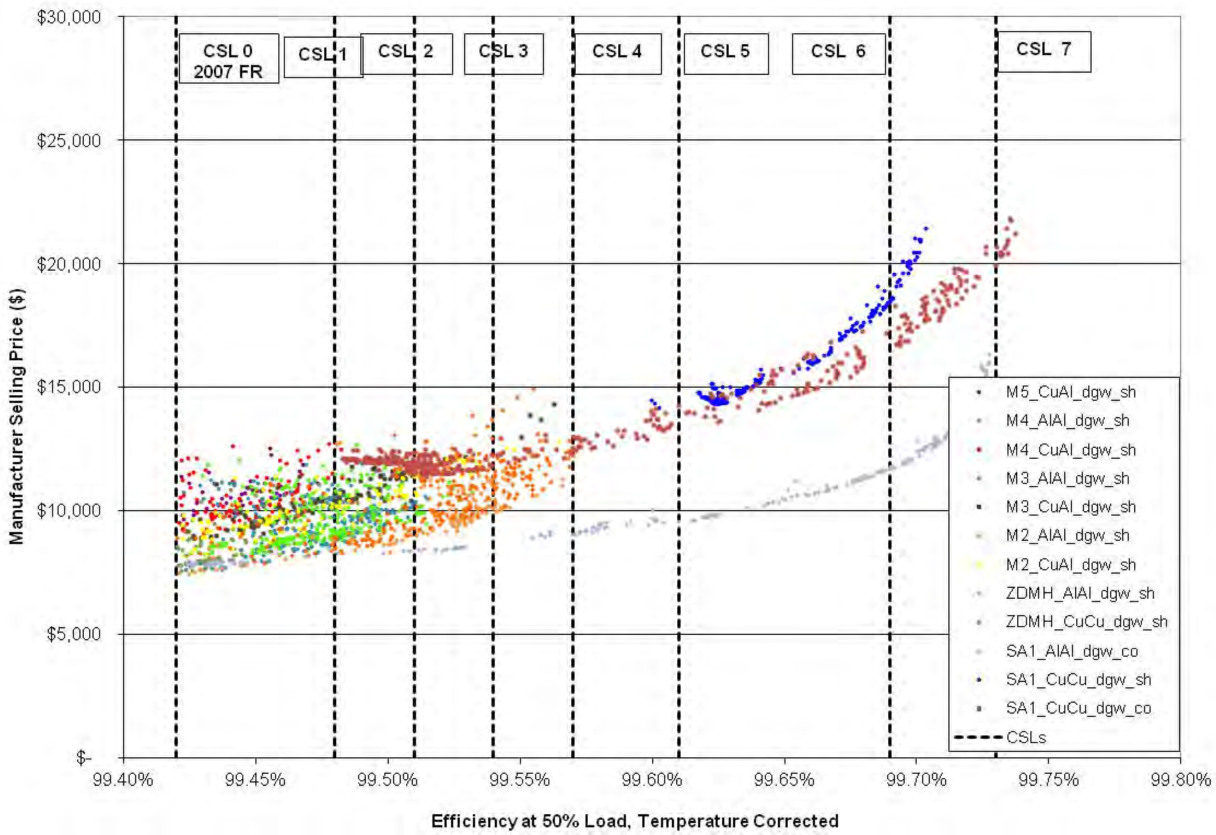

Figure 5.6.6 Engineering Analysis Results, Design Line 3, 2010

Figure 5.6.7 and Figure 5.6.8 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL4, a 150kVA three-phase, liquid-immersed distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.08 percent is most cost-effectively met by designs using M3 core steel (2011) or ZDMH core steel (2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.25 percent, but amorphous designs have a minimum efficiency of 99.27 percent.
- The amorphous designs can reach efficiencies up to 99.60 percent.

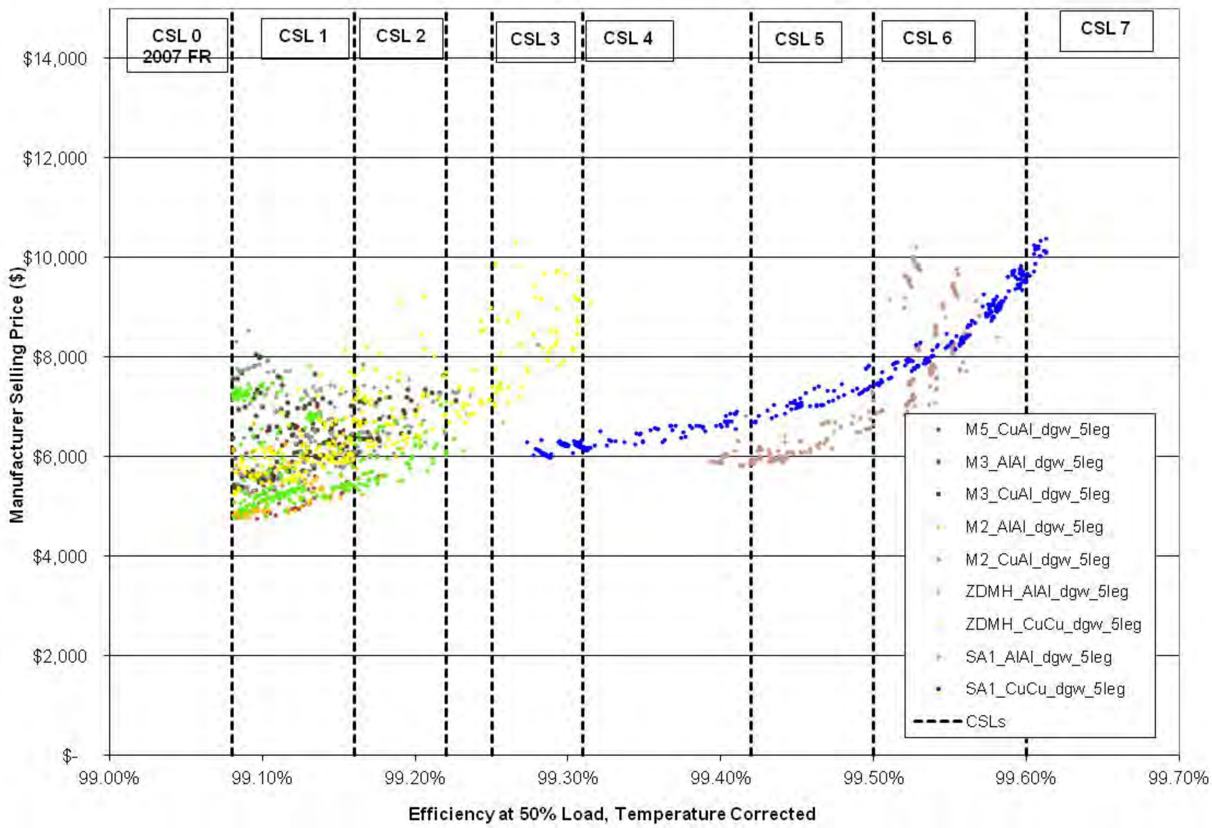

Figure 5.6.7 Engineering Analysis Results, Design Line 4, 2011

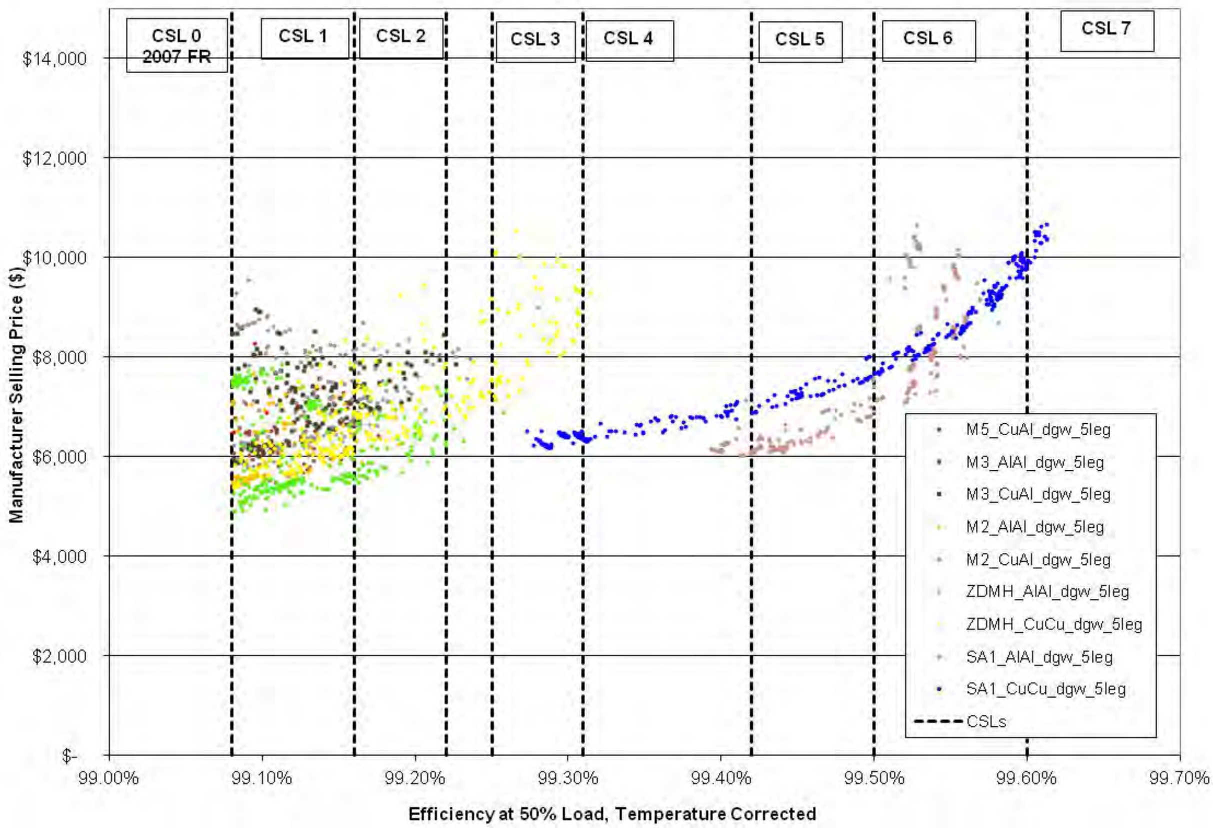

Figure 5.6.8 Engineering Analysis Results, Design Line 4, 2010

Figure 5.6.9 and Figure 5.6.10 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL5, a 1500kVA three-phase, liquid-immersed distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.42 percent is most cost-effectively met by designs using M3 core steel (2011) or ZDMH (2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.50 percent, and can reach efficiencies up to 99.7 percent.

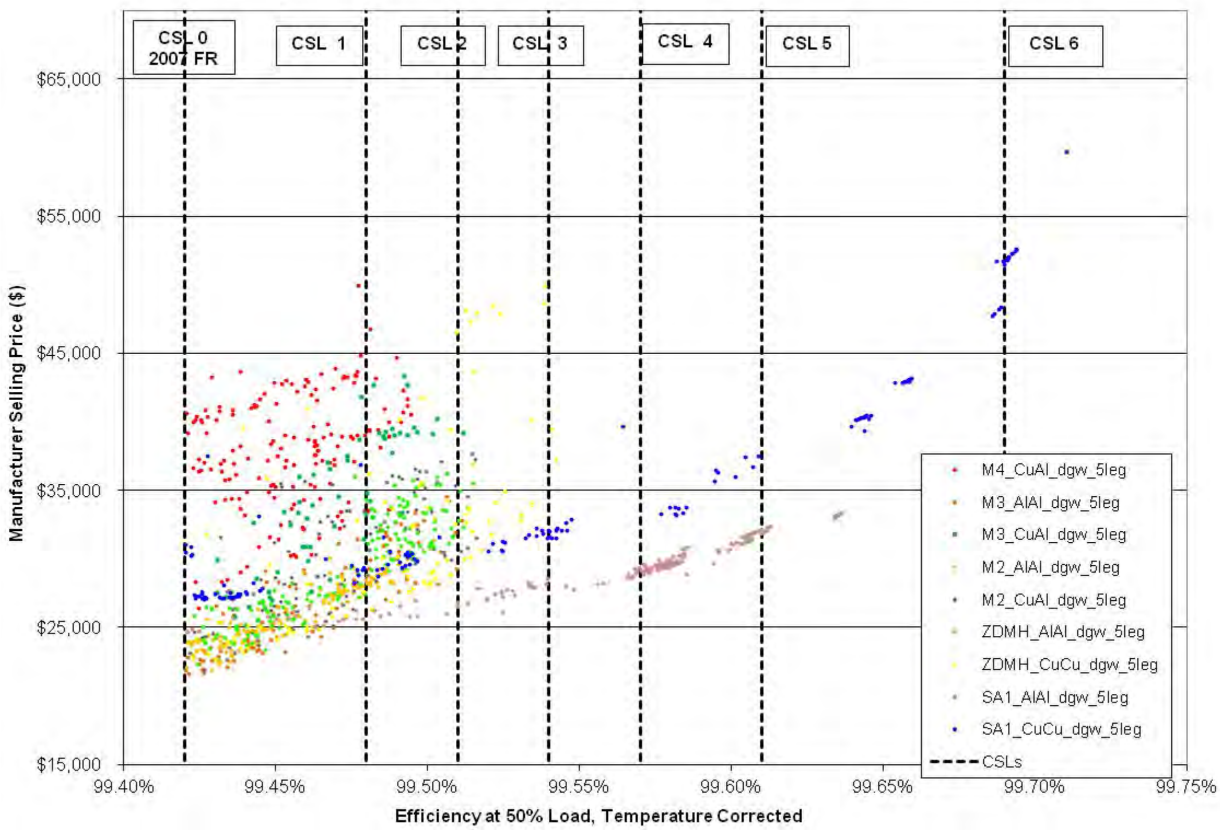

Figure 5.6.9 Engineering Analysis Results, Design Line 5, 2011

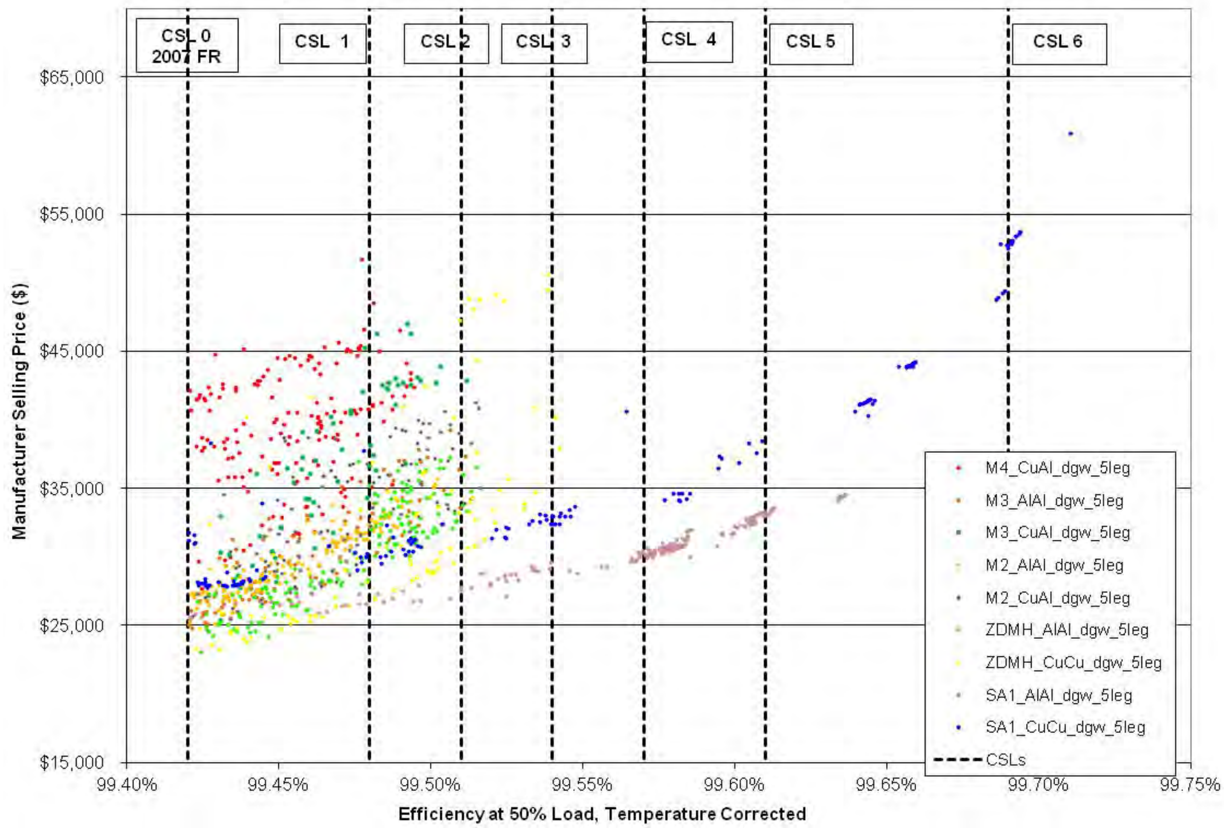

Figure 5.6.10 Engineering Analysis Results, Design Line 5, 2010

Figure 5.6.11 and Figure 5.6.12 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL6, a 25kVA single-phase, low-voltage, dry-type distribution transformer. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.00 percent is most cost-effectively met by designs using M5 core steel (2011 and 2010).
- The NEMA Premium efficiency level of 98.60 percent is met by designs using M4 core steel or better.
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 98.80 percent, and can reach efficiencies up to 99.40 percent.

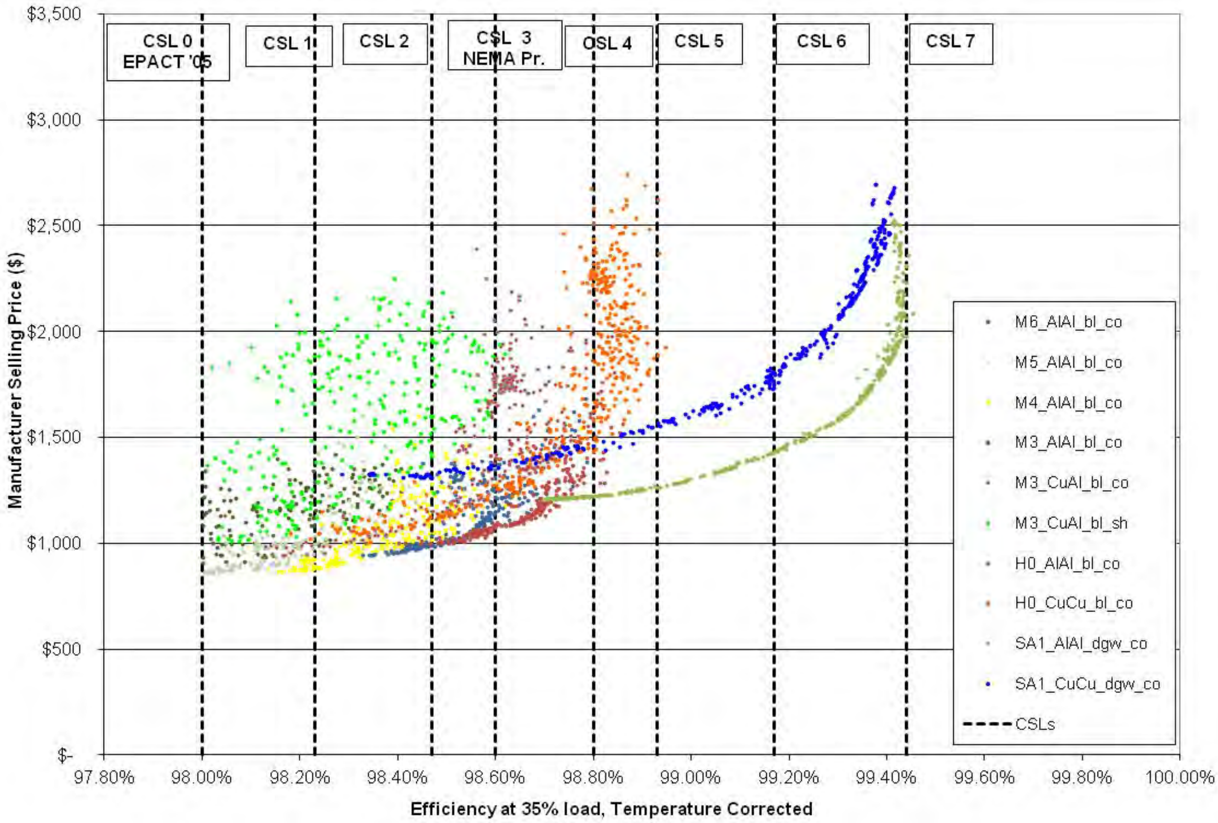

Figure 5.6.11 Engineering Analysis Results, Design Line 6, 2011

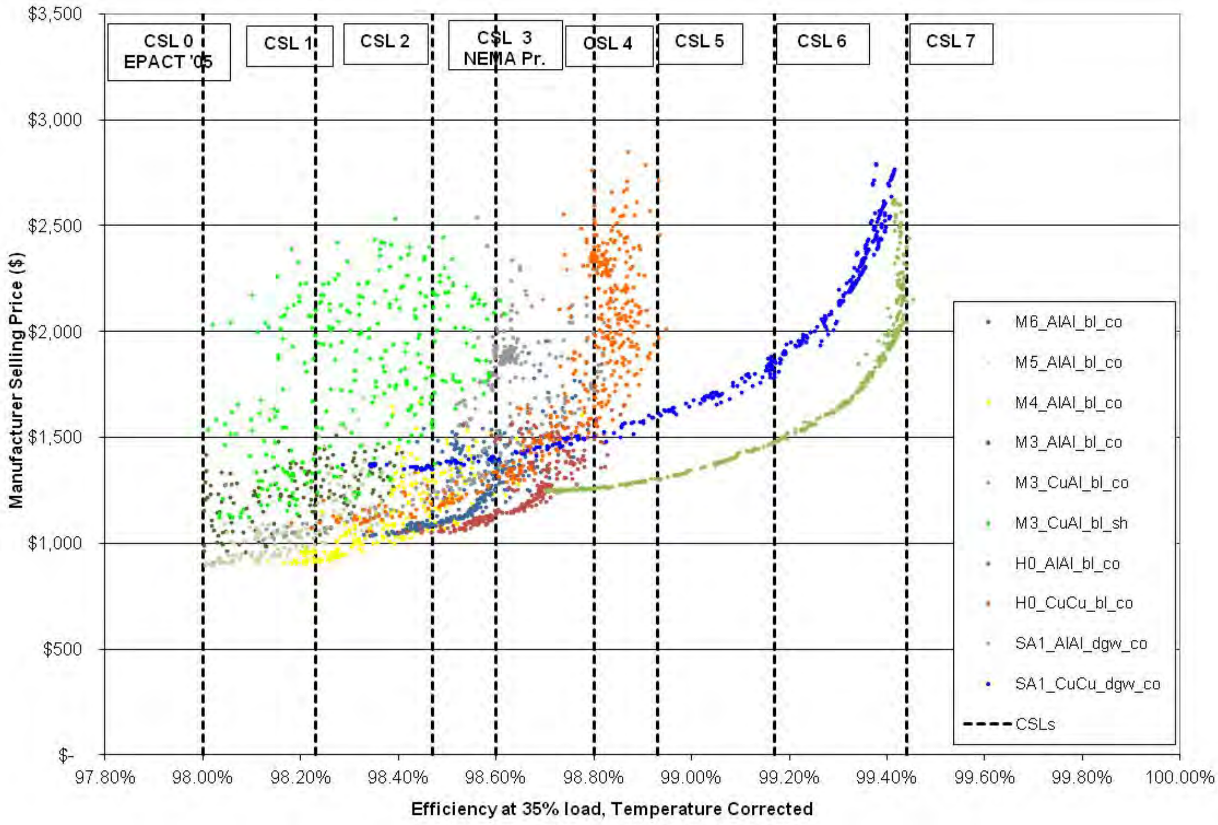

Figure 5.6.12 Engineering Analysis Results, Design Line 6, 2010

Figure 5.6.13 and Figure 5.6.14 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL7, a 75kVA three-phase, low-voltage, dry-type distribution transformer. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.00 percent is most cost-effectively met by designs using M12 core steel (2011 and 2010).
- The NEMA Premium efficiency level of 98.60 percent is met by designs using M3 core steel or better.
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 98.93 percent, and can reach efficiencies up to 99.40 percent.

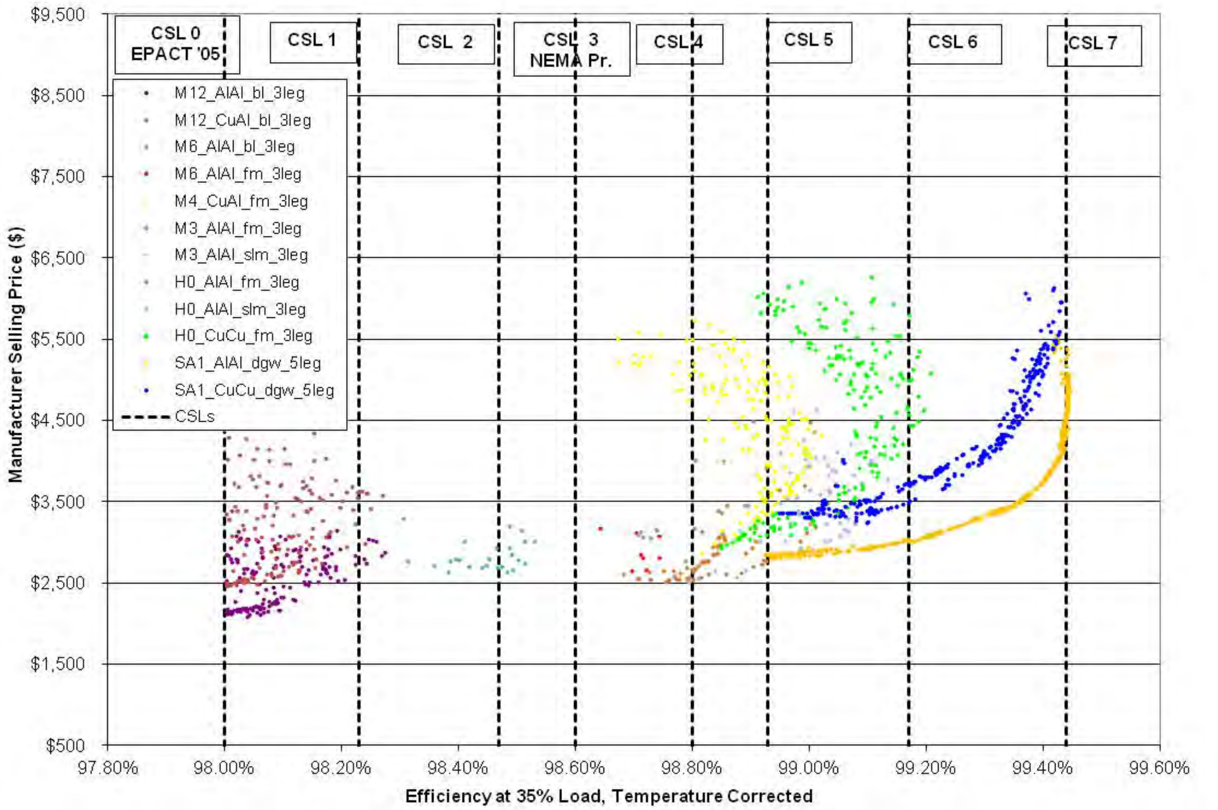

Figure 5.6.13 Engineering Analysis Results, Design Line 7, 2011

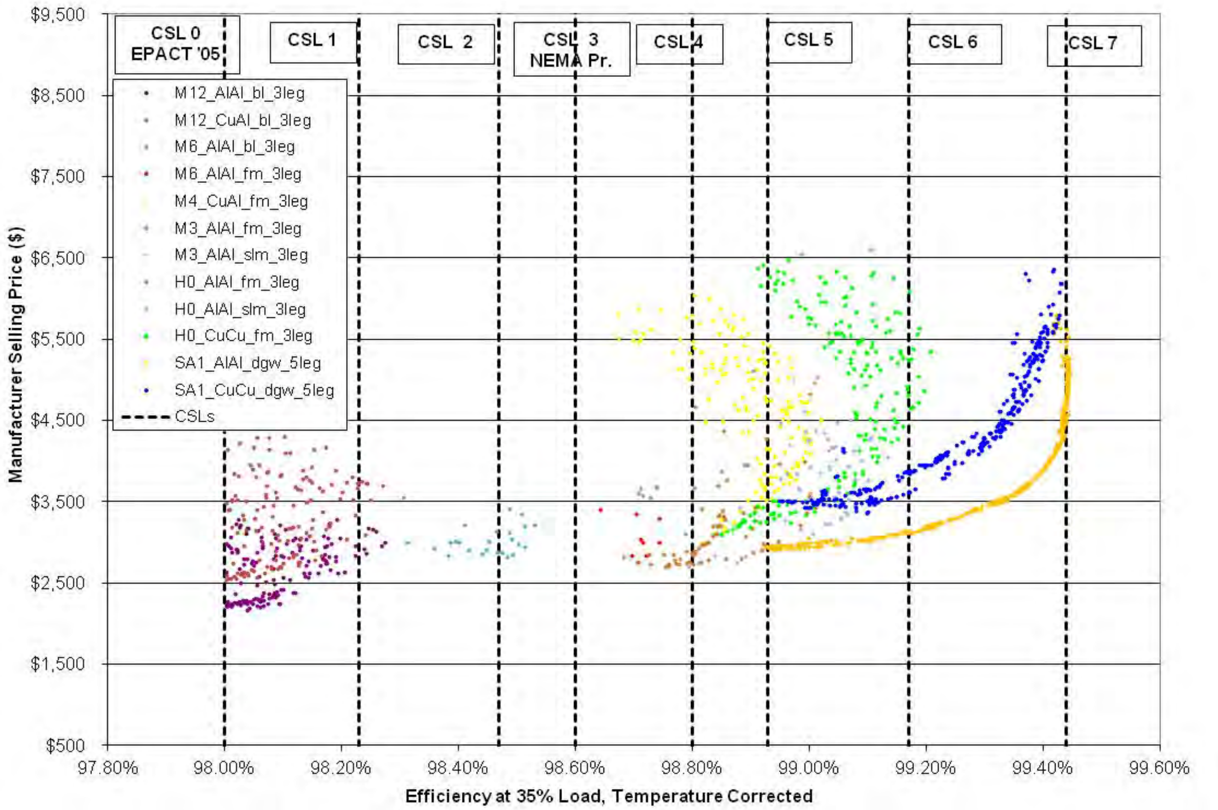

Figure 5.6.14 Engineering Analysis Results, Design Line 7, 2010

Figure 5.6.15 and Figure 5.6.16 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL8, a 300kVA three-phase, low-voltage, dry-type distribution transformer. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.60 percent is most cost-effectively met by designs using M5 core steel (2011) or M6 core steel (2010).
- The NEMA Premium efficiency level of 99.02 percent is met by designs using M3 core steel or better.
- The amorphous metal (SA1) core is the only design that can achieve an efficiency of 99.40 percent or greater, and can reach efficiencies up to 99.60 percent.

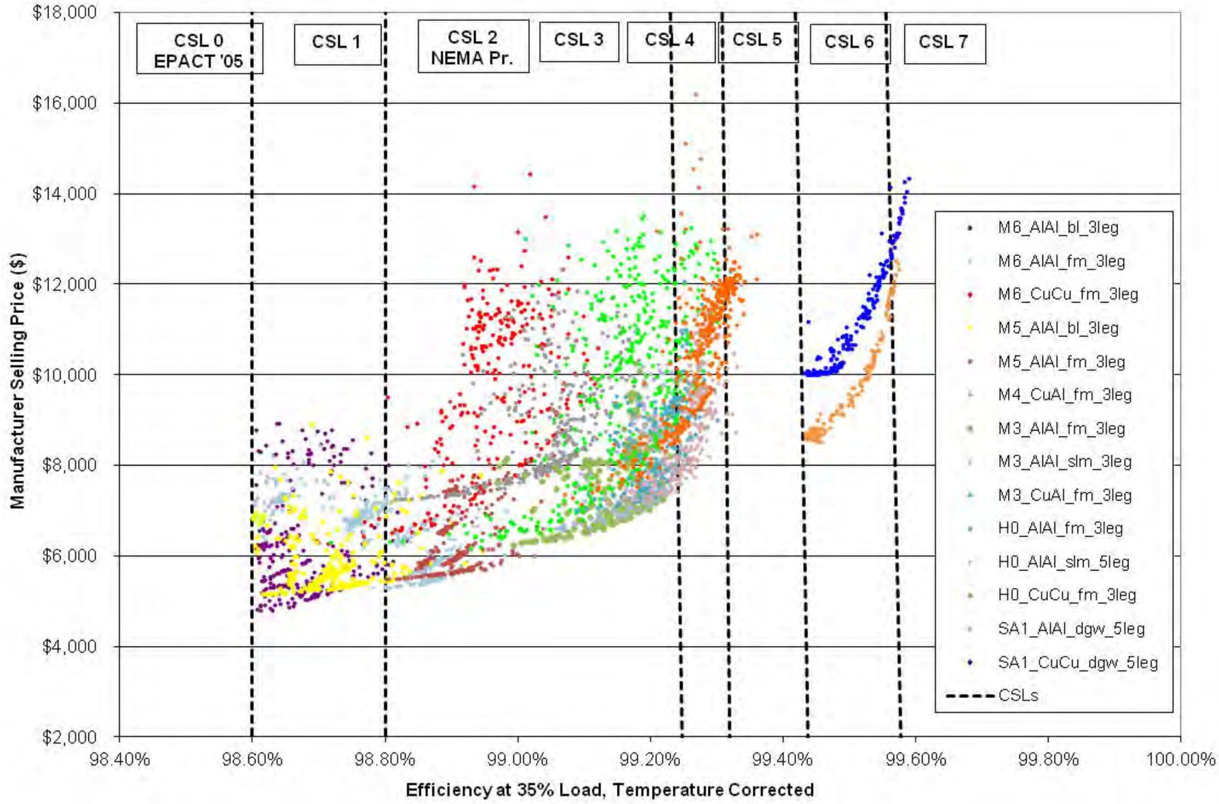

Figure 5.6.15 Engineering Analysis Results, Design Line 8, 2011

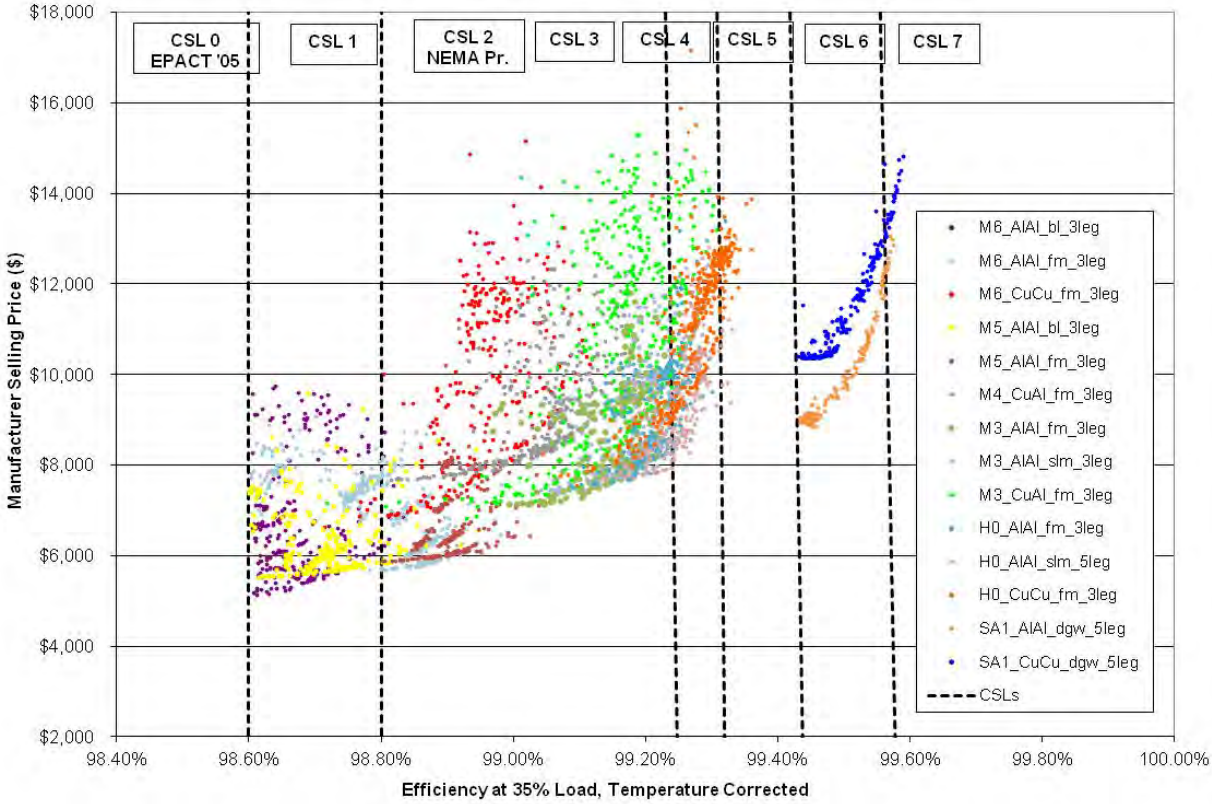

Figure 5.6.16 Engineering Analysis Results, Design Line 8, 2010

Figure 5.6.17 and Figure 5.6.18 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL9, a 300kVA three-phase, medium-voltage, dry-type transformer with a 45kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.82 percent is met by designs using M3 core steel (2011 and 2010).
- The five-legged amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.20 percent, and can reach efficiencies up to 99.59 percent.

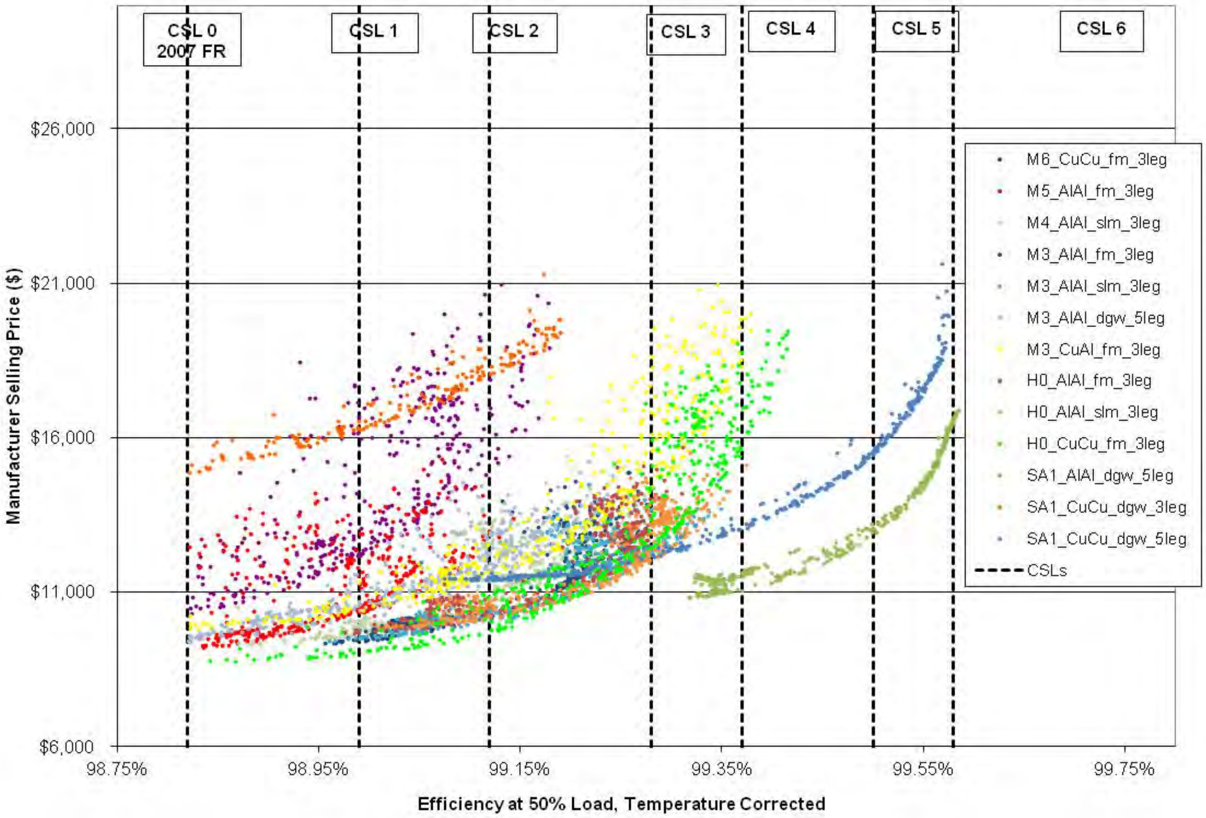

Figure 5.6.17 Engineering Analysis Results, Design Line 9, 2011

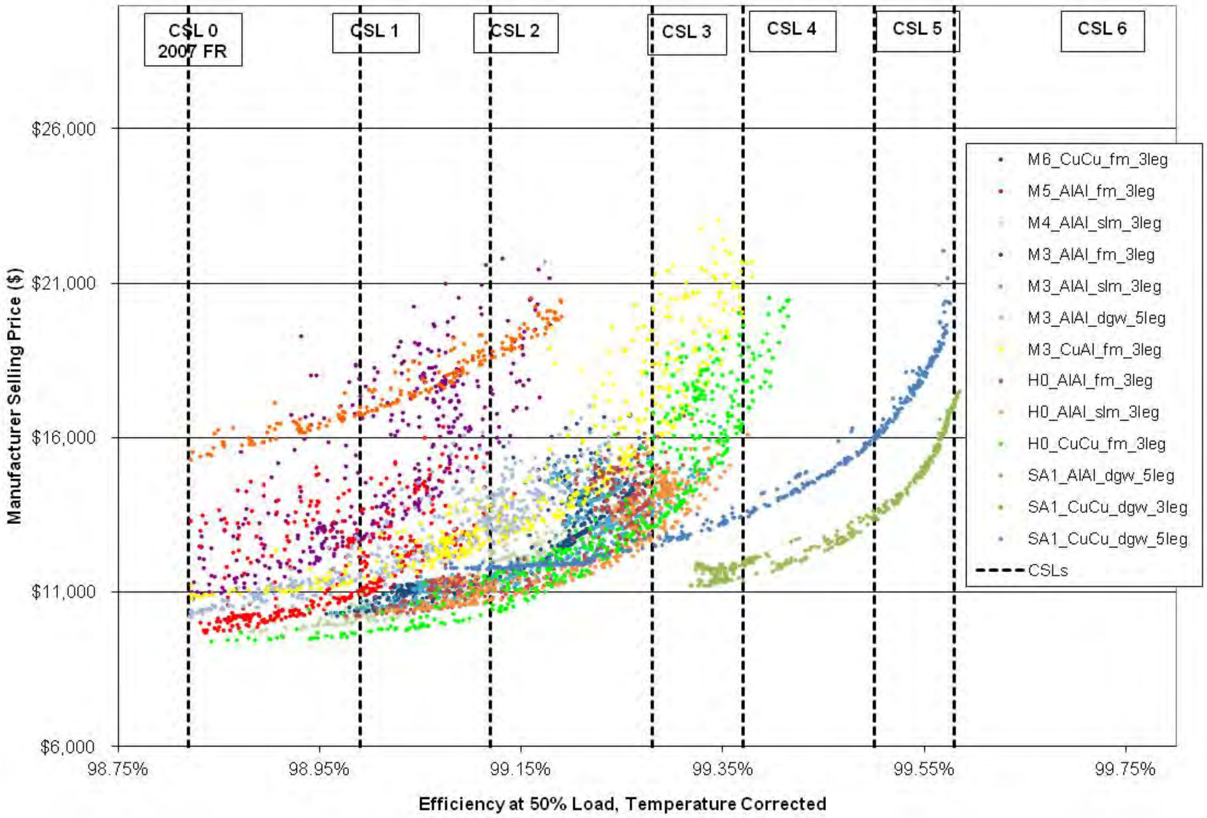

Figure 5.6.18 Engineering Analysis Results, Design Line 9, 2010

Figure 5.6.19 and Figure 5.6.20 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL10, a 1500kVA three-phase, medium-voltage, dry-type transformer with a 45kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.22 percent is most cost-effectively met by designs using M4 core steel (2011 and 2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.50 percent, and can reach efficiencies up to 99.67 percent.

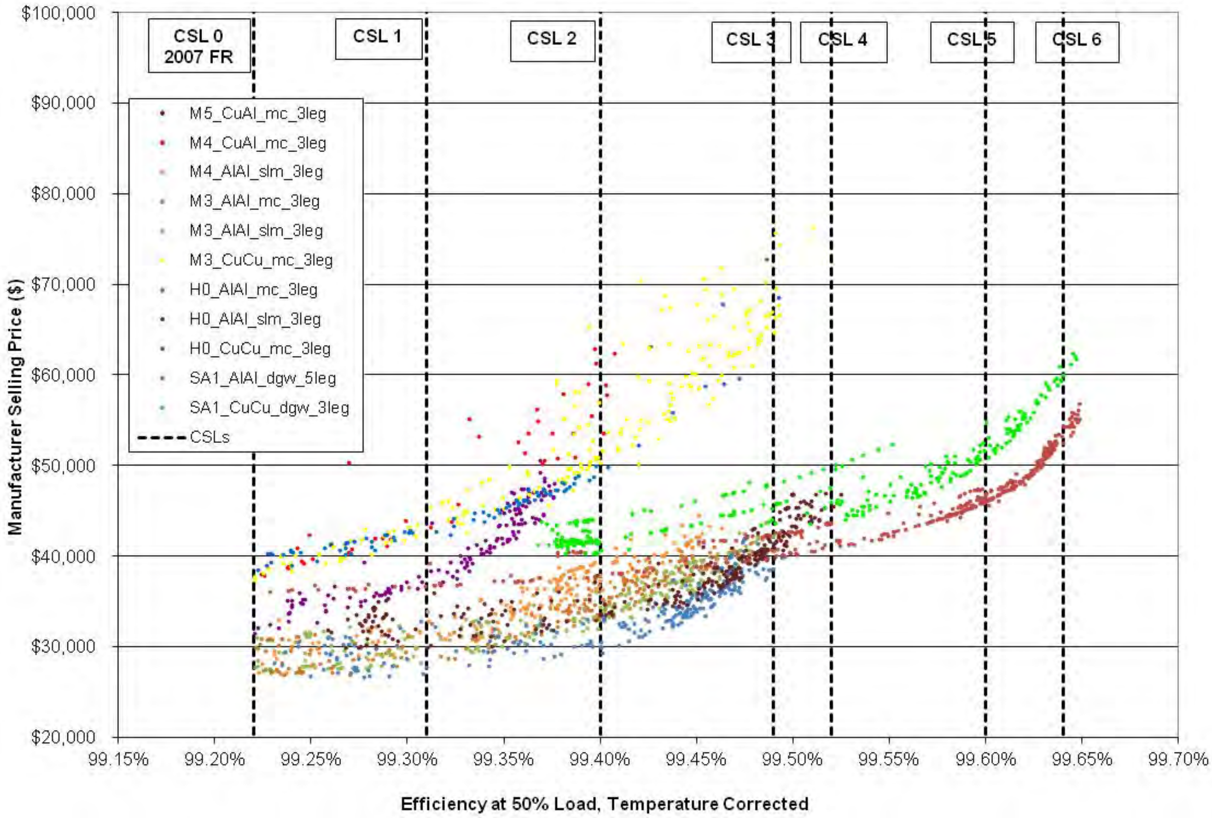

Figure 5.6.19 Engineering Analysis Results, Design Line 10, 2011

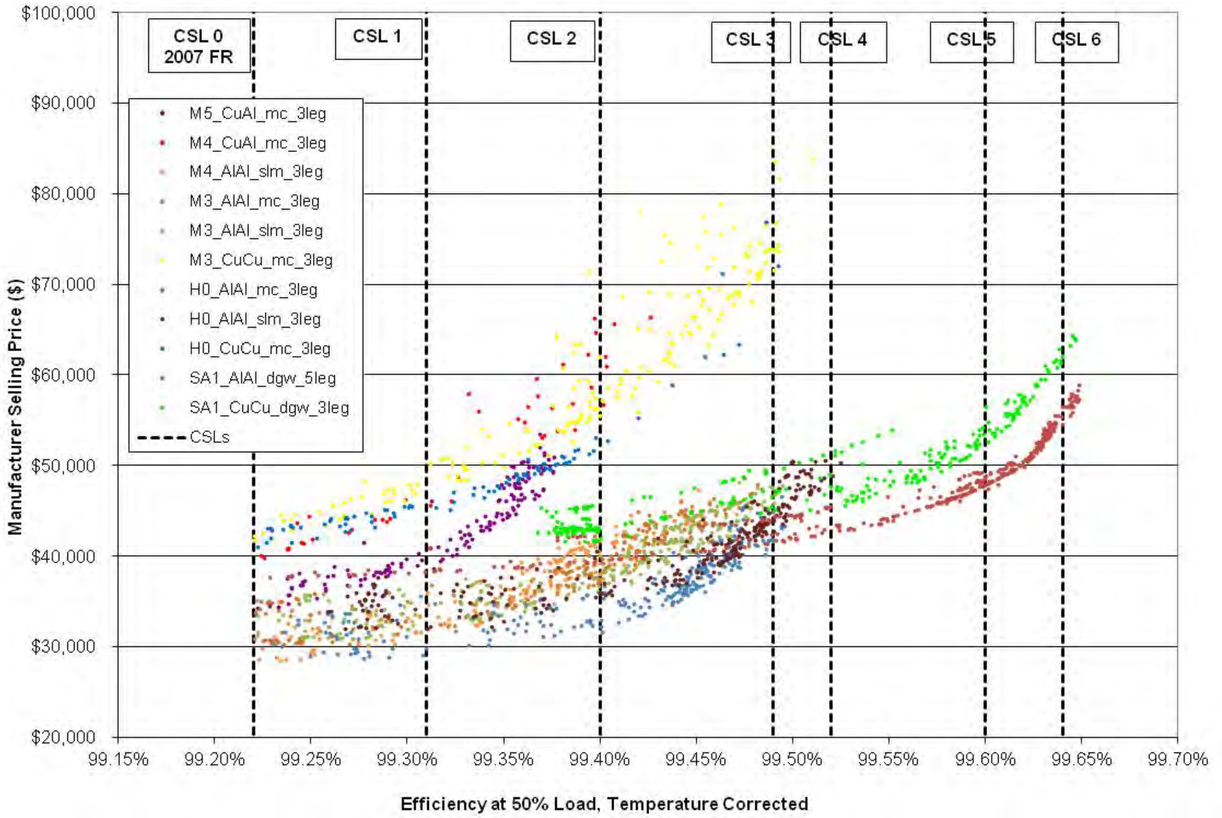

Figure 5.6.20 Engineering Analysis Results, Design Line 10, 2010

Figure 5.6.21 and Figure 5.6.22 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL11, a 300kVA three-phase, medium-voltage, dry-type transformer with a 95kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.67 percent is most cost-effectively met by designs using M3 core steel (2011) or H0 core steel (2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.00 percent, and can reach efficiencies up to 99.50 percent.

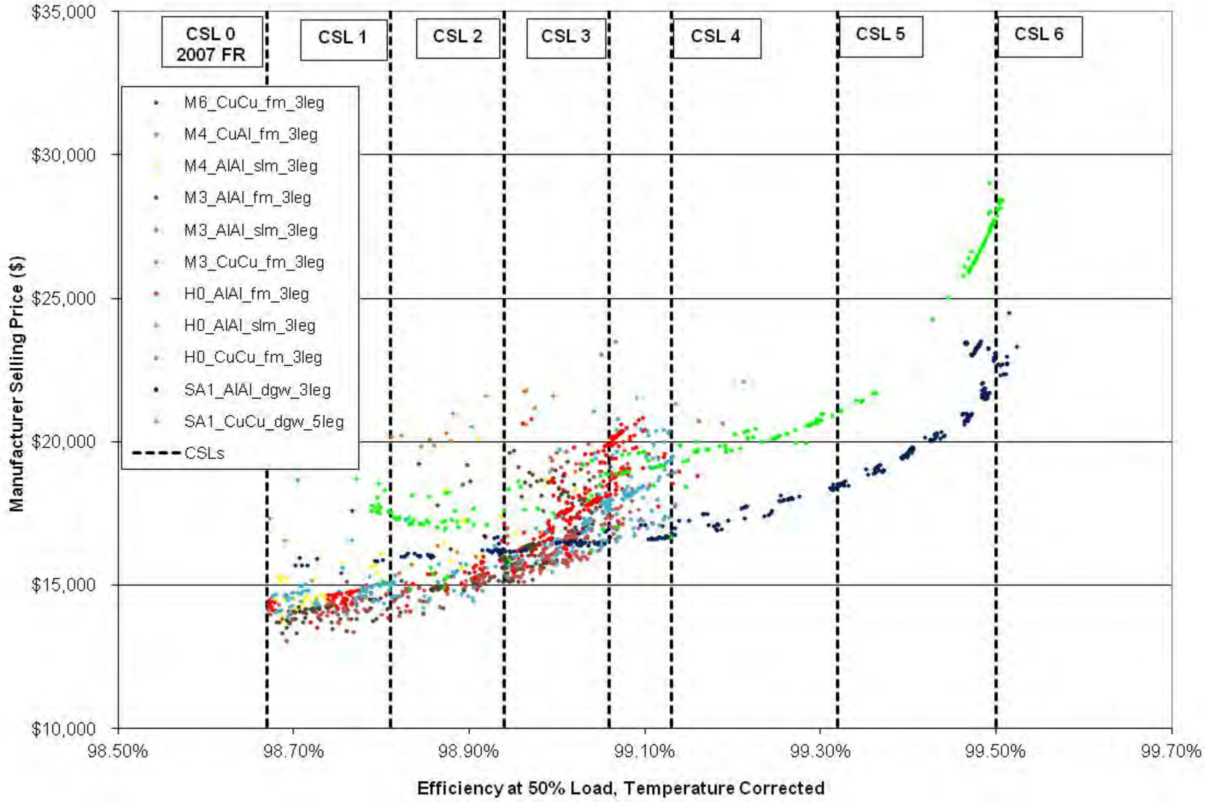

Figure 5.6.21 Engineering Analysis Results, Design Line 11, 2011

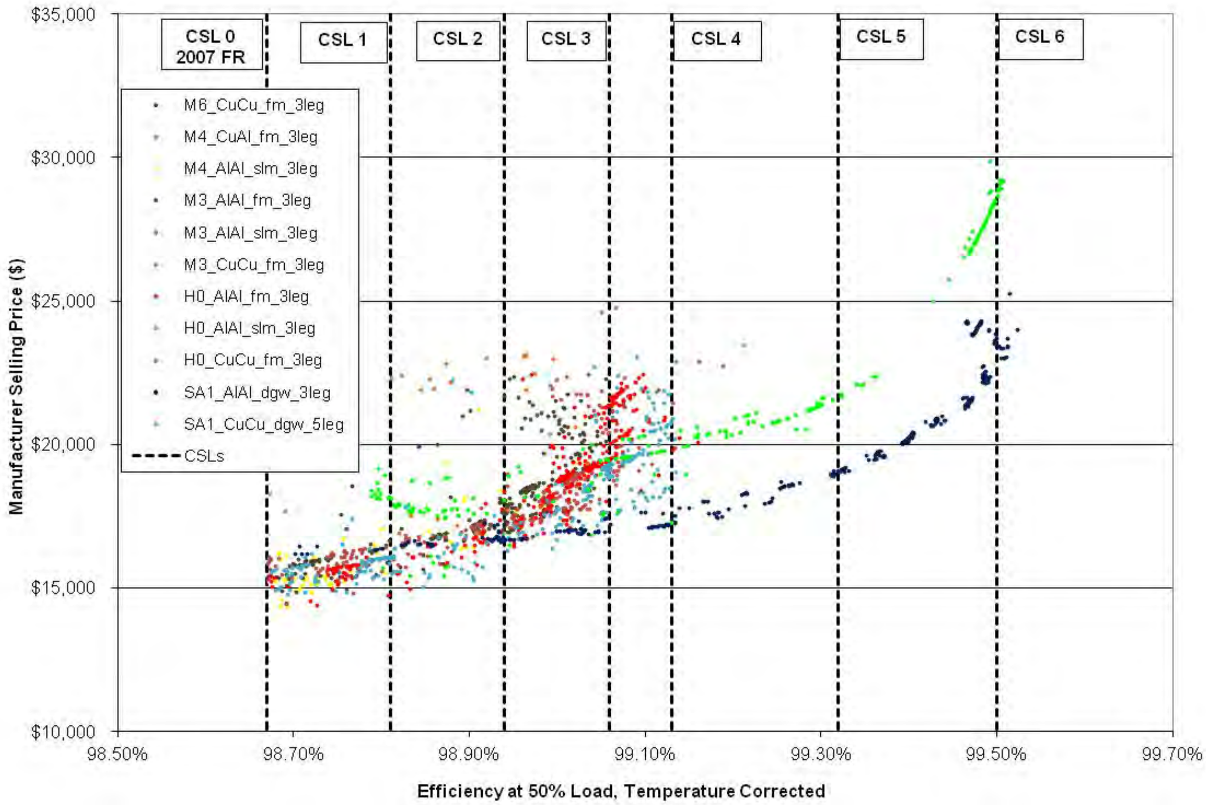

Figure 5.6.22 Engineering Analysis Results, Design Line 11, 2010

Figure 5.6.23 and Figure 5.6.24 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL12, a 1500kVA three-phase, medium-voltage, dry-type transformer with a 95kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.12 percent is most cost-effectively met by designs using M5 core steel (2011 and 2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.40 percent, and can reach efficiencies above 99.65 percent.

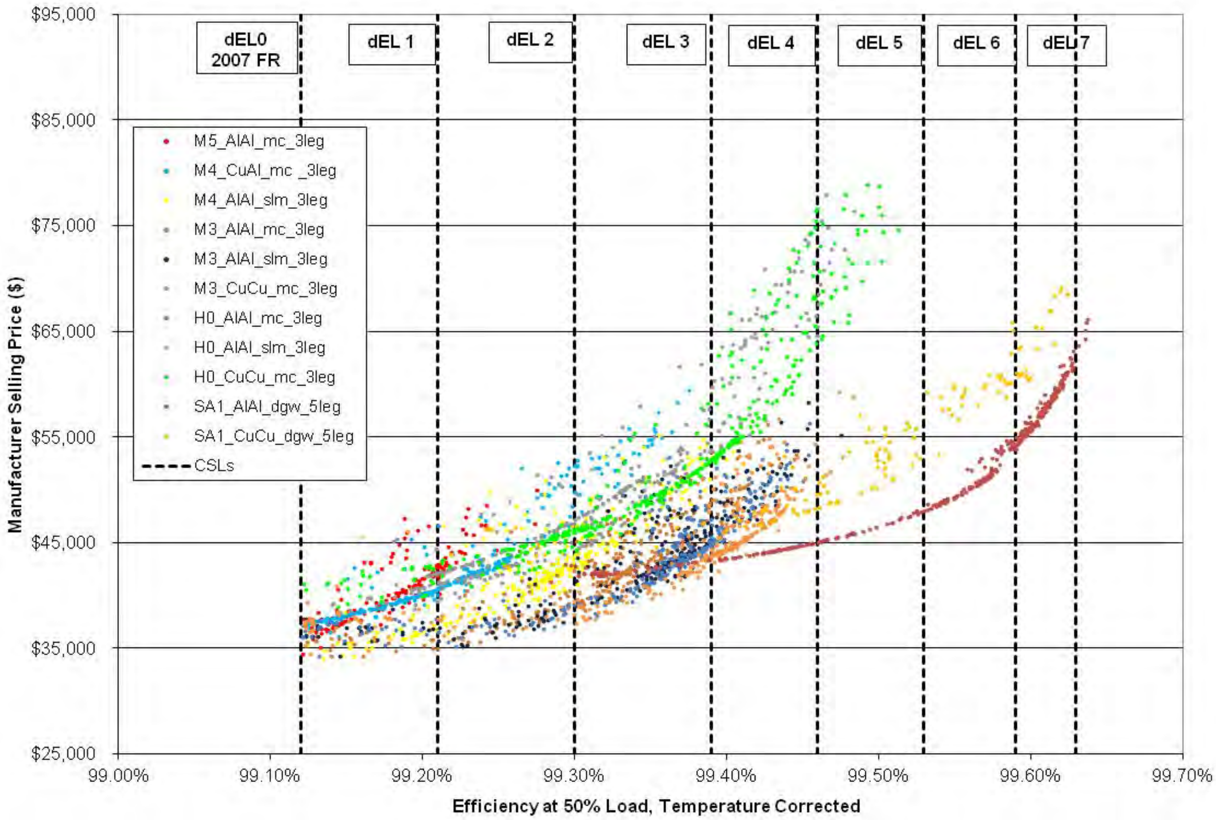

Figure 5.6.23 Engineering Analysis Results, Design Line 12, 2011

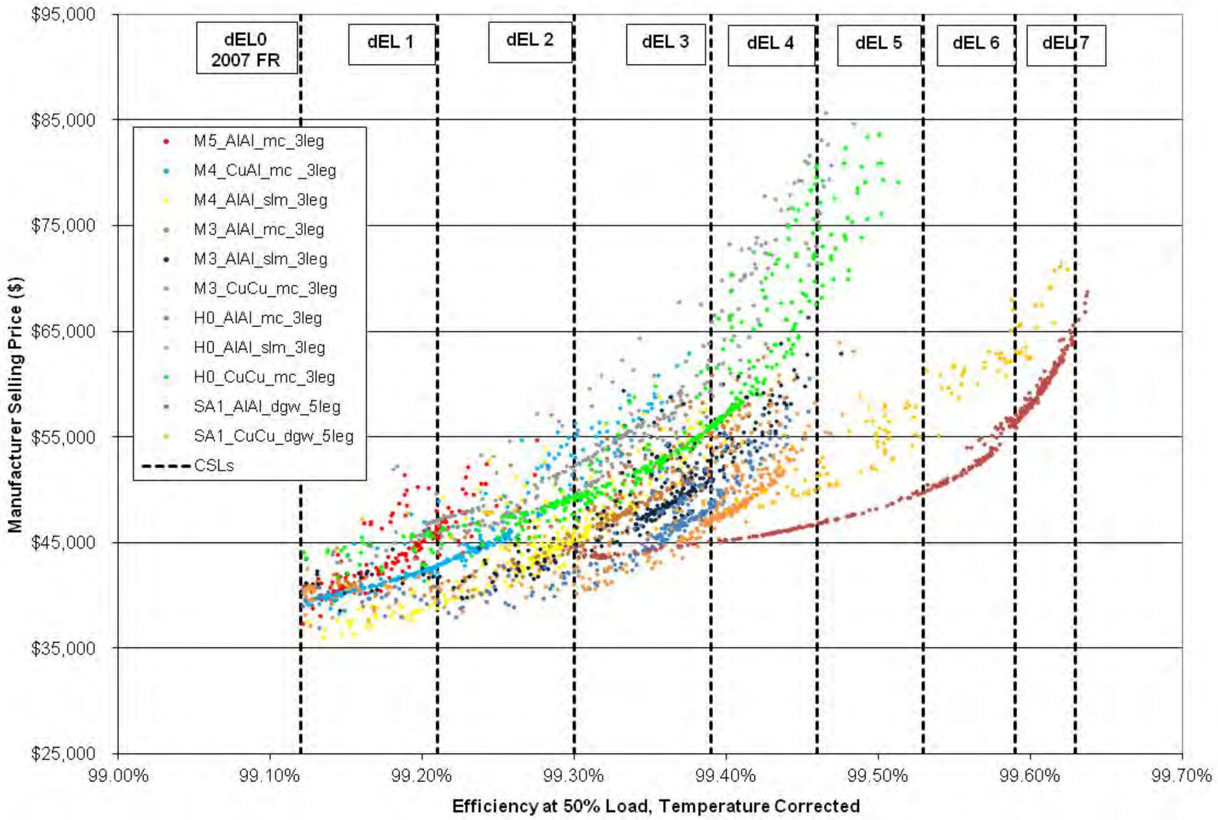

Figure 5.6.24 Engineering Analysis Results, Design Line 12, 2010

Figure 5.6.25 and Figure 5.6.26 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL13A, a 300kVA three-phase, medium-voltage, dry-type transformer with a 125kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.63 percent is most cost-effectively met by designs using M4 core steel (2011 and 2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.10 percent, and can reach efficiencies up to 99.48 percent.

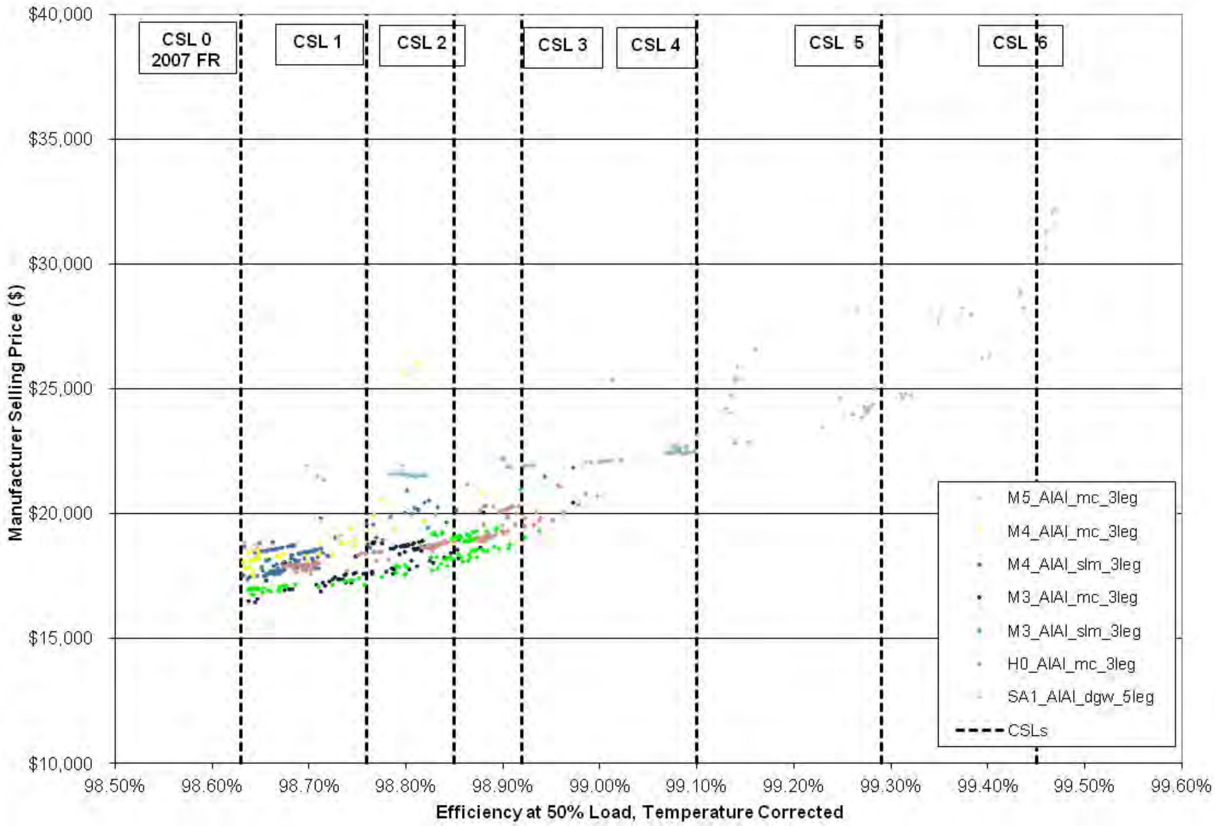

Figure 5.6.25 Engineering Analysis Results, Design Line 13A, 2011

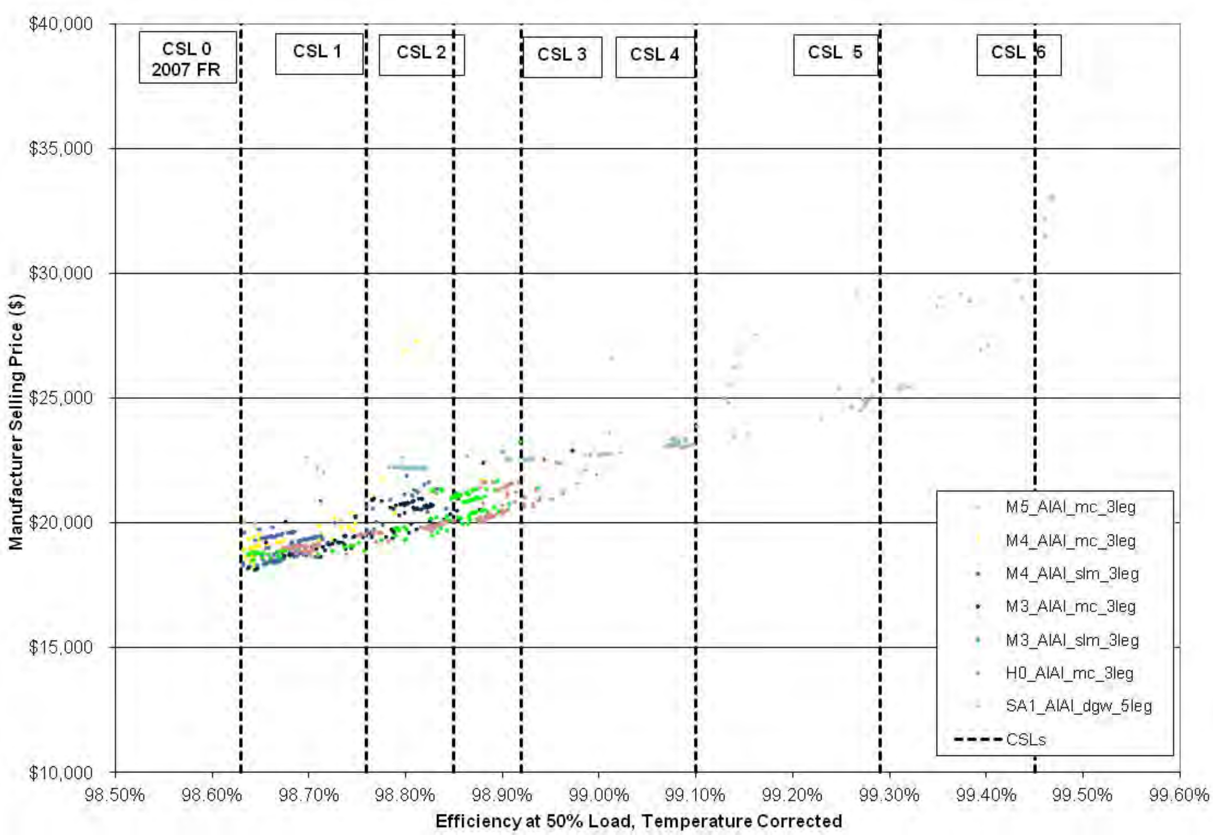

Figure 5.6.26 Engineering Analysis Results, Design Line 13A, 2010

Figure 5.6.27 and Figure 5.6.28 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from DL13B, a 2000kVA three-phase, medium-voltage, dry-type transformer with a 125kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.15 percent is most cost-effectively met by designs using M3 core steel (2011) or M4 core steel (2010).
- The amorphous metal (SA1) core is the most cost-effective design for any efficiency level above 99.43 percent, and can reach efficiencies up to 99.58 percent.

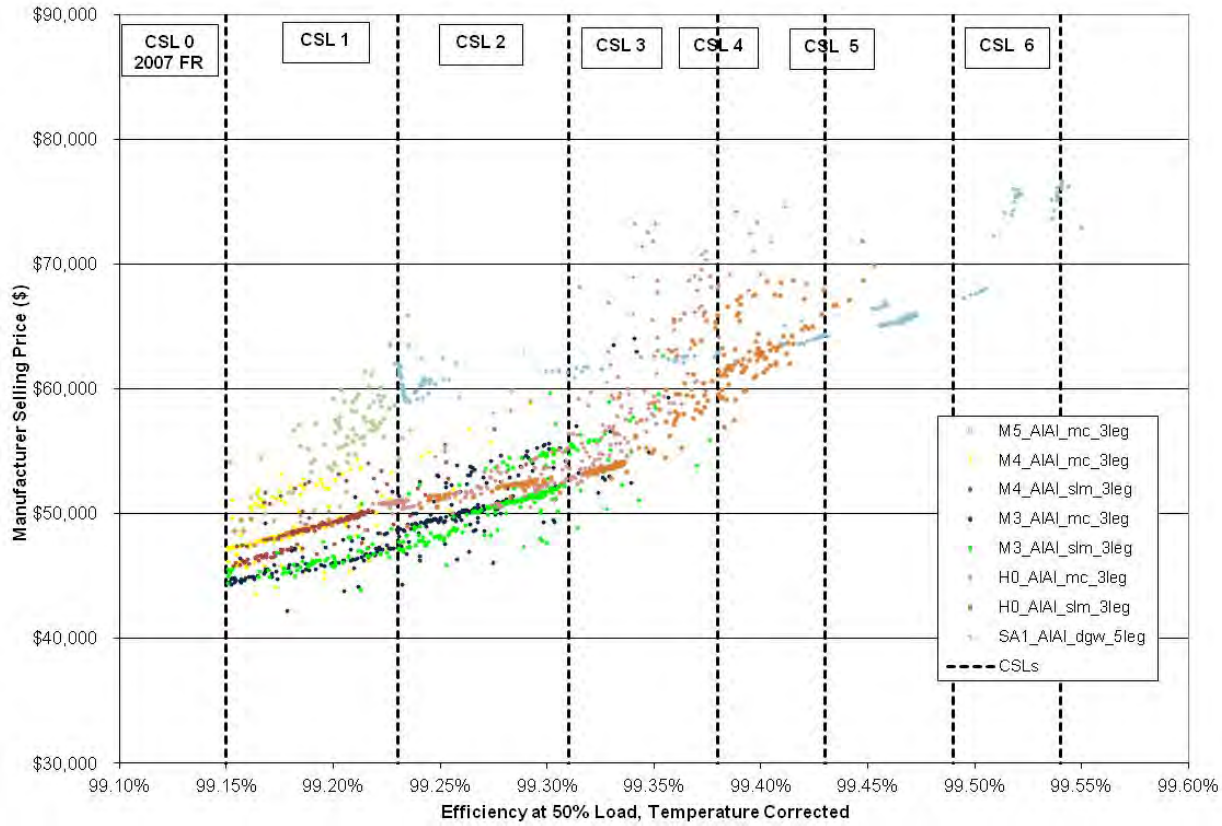

Figure 5.6.27 Engineering Analysis Results, Design Line 13B, 2011

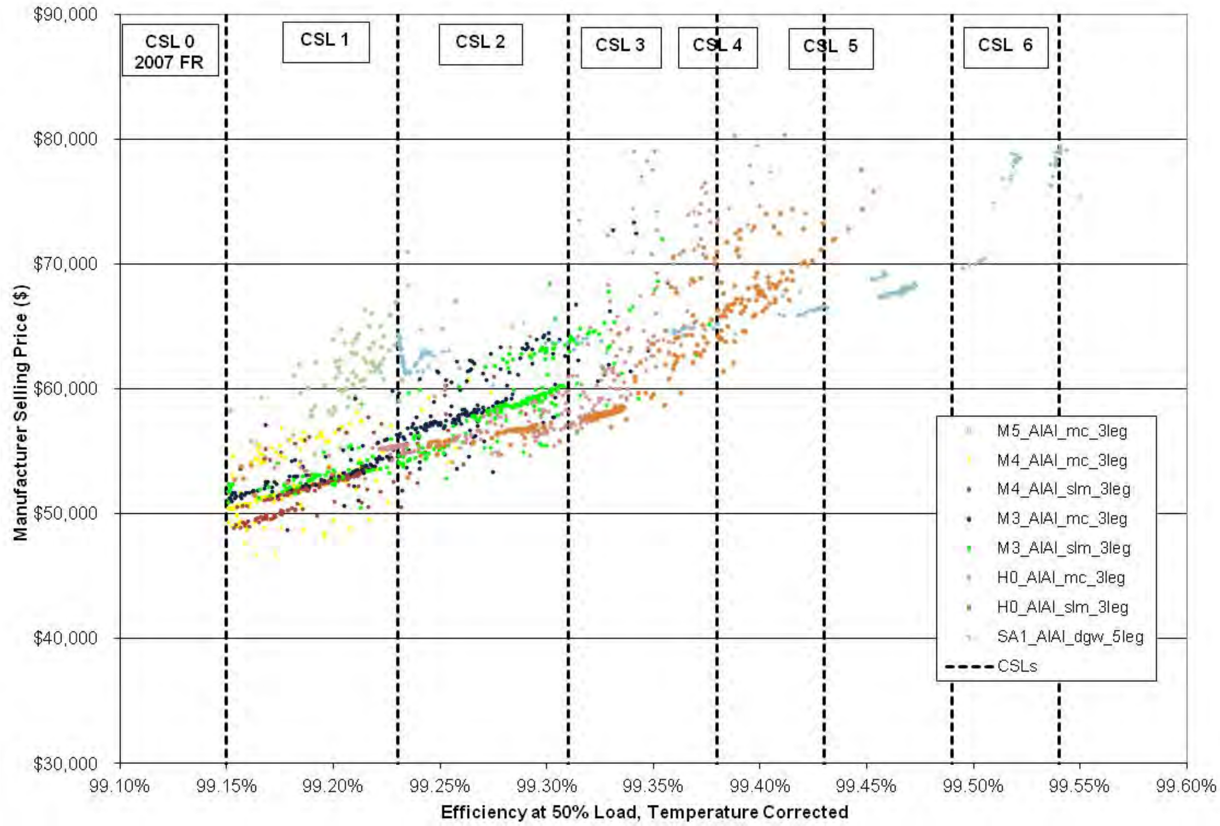

Figure 5.6.28 Engineering Analysis Results, Design Line 13B, 2010

5.6.2 Symmetric Core Designs

In the preliminary analysis, DOE generated cost-efficiency relationships for symmetric core design transformers by adjusting comparable traditional core design models. To do this, DOE reduced core losses and core weight while increasing labor costs to approximate the symmetric core designs. DOE based these approximations on conversations with manufacturers, and published literature. In the preliminary analysis, DOE requested information and data regarding symmetric core designs. However, DOE was unable to obtain sufficient data to more accurately approximate the cost and efficiency of symmetric core designs. Without further information, DOE did not consider symmetric core designs for the NOPR analysis, although it has not screened these designs out of the rulemaking. DOE welcomes comment and submission of engineering data that would be useful in analyzing symmetric core designs for the final rule.

5.7 THREE EXAMPLE DESIGNS AND COST BREAKDOWNS

This section presents some of the OPS transformer designs from DOE's engineering analysis database. As discussed earlier, to prepare a cost-efficiency relationship on selected representative units, DOE contracted Optimized Program Service (OPS), a software company specializing in transformer design since 1969. Using a range of input parameters and material prices, more than 39,000 transformer designs were created by OPS for DOE's analysis. For each design, the software generates specific information about the core and coil, including physical characteristics, dimensions, material requirements and mechanical clearances, as well as a complete electrical analysis of the final design. For information on OPS and their software, visit their website: http://www.opsprograms.com/home.html.

To illustrate the typical output from the OPS software, a design from each of the three superclasses (*i.e.*, liquid-immersed, low-voltage dry-type and medium-voltage dry-type) are presented in this section. As these designs illustrate, the software output is used to create a bill of materials, which is marked-up to arrive at the manufacturer's selling price. The OPS software provides an electrical analysis including efficiency, which, when plotted with the manufacturer's selling price, constitutes the primary output of the engineering analysis.

The three distribution transformers presented are from design lines 1, 7, and 12. Across all the design lines, the complete database of designs contains 39,618 distribution transformer specification and winding sheets, bills of materials, and performance reports. Any infeasible designs or designs below the minimum efficiency standard are removed and then this design database is used by the LCC analysis (see chapter 8) as it simulates purchases of distribution transformers in the marketplace.

- ***Design Line 1*****:** 50 kVA single-phase, liquid-immersed. M2 core steel with copper primary and aluminum secondary windings (M2CuAl) at a $3.00 A and a $1.20 B evaluation formula.

- ***Design Line 7***: 75 kVA three-phase, low-voltage dry-type. M6 full-mitered core steel with aluminum primary and secondary windings (M6AlAl) at a $0.50 A and a $0.10 B evaluation formula.

- ***Design Line 12***: 1500 kVA three-phase, medium-voltage dry-type. M3 step-lap core steel with aluminum primary and secondary windings (M3AlAl) at a $1.50 A and a $0.30 B evaluation formula.

For the three designs presented, the design detail report is followed by a bill of materials showing the cost calculation, and a pie chart providing a breakdown of the final selling price.

5.7.1 Design Details Report for Transformer from Design Line 1

A design specification report for a 50kVA single-phase liquid-immersed transformer appears below. This design incorporates M2 core steel, with a copper primary and an aluminum secondary. The evaluation factors for this design are $3.00 A and $1.20 B. The bill of materials and associated breakdown of costs for this design are also reported, after the design and electrical analysis reports.

DL1M2CUAL-3-1.2-F

OPTIMIZED PROGRAM SERVICE

CLEVELAND OHIO 101800

2011- 8-25 14:31: 7

DESIGN ID DL1-PM2CUAL

DG-CORE SHELL TYPE TRANSFORMER

FREQUENCY 60.0 KVA RATING 50.00 @ 100.00% DUTY CYCLE

CORE M2 M 2 THICKNESS .0070

D: 7.500 E: 2.000 F: 3.250 G: 7.875

EFF. AREA 28.50 WEIGHT 224.442

WNDG FORM: INS. DIM. 7.750 X 4.186 THICKNESS 0.072 LENGTH 7.375

COIL SPECIFICATIONS

WNDG	WIRE		LENGTH	MEAN TURNS	MARGIN	WT
S1	0.035X 6.625	AL	33.91	27.13	0.375	9.206
P1	1X 1 #15 ROUND	H CU	5835.48	37.05	0.375	57.769
S2	0.035X 6.625	AL	58.64	46.91	0.375	15.917

NUMBER OF COILS 1

TOTAL BARE CONDUCTOR WEIGHT 82.892
TOTAL INSULATION WEIGHT 3.738

WNDG	TURNS	LO TAP	HI TAP	LAYRS	T/L	LAYR INS	SEC. INS	BUILD
S1	15.0			15	1.0	1(0.0050)	1(0.0300)	0.595
P1	1800.0	1710.0	1890.0	18	106.0	4(0.0050)	1(0.1000)	1.425
S2	15.0			15	1.0	1(0.0050)	1(0.0500)	0.595

TOTAL BUILD(%) 88.22

WNDG	TAPS: TURNS(VOLTS)	
P1	1755.0(14040.00)	1845.0(14760.00)

WNDG	INTERNAL DUCTS(100.00)	%EFF	EXTERNAL DUCTS(100.00)	%EFF
S1	3 0.125 X 0.125	END		
P1	6 0.125 X 0.125	END	0.125 X 0.125	END
S2	1 0.125 X 0.125	END	0.125 X 0.125	END

ELECTRICAL ANALYSIS

WNDG	FULL-LOAD VOLTS	TAP VOLTS LOW	HIGH	TEST KV	LOAD CURRENT	RESIST. @20 C.	CURRNT DENS.	%REG
P1	14400.00	13680.00	15120.00	34.5	3.519	18.50509	1370.12	
S1	118.80	120.00	NLV	10.0	208.330	0.00196	899.48	1.0
S2	118.43	120.00	NLV	10.0	208.330	0.00338	899.48	1.3

```
                                               DL1M2CUAL-3-1.2-F
                      F.L.         N.L.     DESTRUCTION FACTOR          1.025
FLUX DENS.          16.235       16.326     LEAKAGE INDUCTANCE MHYS   212.003
CORE LOSS          109.405      111.693     POWER FACTOR                1.000
COIL LOSS          584.191        0.006     IMPEDANCE %                 2.24
EXCIT. VA          225.863      236.831     EFFICIENCY %               98.63
EXCIT. CURR.         0.016        0.016     TANK OIL          18.26   GAL.
                                            OIL WEIGHT       139.18    LB.

AMBIENT TEMP.       20.00                     NOMINAL LENGTH        14.593
TEMP.RISE           65.00                     NOMINAL  DEPTH        17.250
OPERATING TEMP.     85.00                     NOMINAL HEIGHT        11.875

                   S1   P1   S2
  GRADIENT:        1.2  6.2  3.6
  AVG. OIL RISE:        56.
  TOP  OIL RISE:        74.0

SHAPE   TOTAL COOLING AREA    TANK AREA   RAD. AREA    RAD. OIL/GAL. TYPE
-------------------------------------------------------------------------
RECTG.      1429.952          1280.480     149.472          0.162      C

TANK DIMENSIONS
-------------------------
 LENGTH      =      16.093
 DEPTH       =      18.750
 OIL HEIGHT  =      18.375

        2
 COND. I R LOSS               =    567.1666
 COND. EDDY CURRENT LOSS      =      2.8450
 OTHER STRAY LOSS             =     14.1792
 K VALUE                      =      1.0000
 % LOSS                       =      2.5000


                                  o
AT REFERENCE TEMP.         85.0
------------------------------
COIL LOSS    =    584.197
IMPEDANCE % =       2.238
```

% LOAD	% REG	% EFF	% IR	% IX	% IZ	CORE	LOAD LOSS	TEMP RISE
5	0.05	95.68	0.048	0.101	0.112	111.60	1.27	14.7
10	0.10	97.72	0.093	0.197	0.218	111.50	4.98	15.1
15	0.14	98.39	0.139	0.294	0.325	111.40	11.14	15.8
20	0.19	98.71	0.185	0.391	0.432	111.31	19.82	16.9
25	0.24	98.87	0.232	0.487	0.540	111.21	31.07	18.2
30	0.29	98.97	0.280	0.584	0.648	111.11	44.95	19.8
35	0.34	99.02	0.328	0.681	0.756	111.01	61.57	21.6
50	0.51	99.05	0.482	0.973	1.085	110.68	128.95	28.9
60	0.62	99.01	0.591	1.168	1.309	110.45	189.88	35.2
65	0.68	98.98	0.649	1.265	1.422	110.33	225.66	38.7
75	0.81	98.90	0.770	1.461	1.652	110.08	308.82	46.6
80	0.88	98.85	0.833	1.559	1.768	109.95	356.67	51.0
100	1.16	98.63	1.093	1.953	2.238	109.40	584.19	65.0
125	1.46	98.39	1.369	2.448	2.804	108.82	914.95	65.0

Table 5.7.1 provides the bill of materials which was calculated from the OPS design details report. This bill of materials uses the raw material prices given in this chapter for fixed

and variable materials used in building the transformer. These materials are then marked-up at the bottom of the table to arrive at the manufacturer's selling price.

Table 5.7.1 Bill of Materials for Transformer from Design Line 1

Bill of Materials and Labor for liquid-immersed, single-phase, pad-mount, 50kVA

A$ Input	$3.00			
B$ Input	$1.20			
Efficiency at	99.00%			

Material Item	**Type**	**Quantity**	**$ Each**	**$ Total**
Core Steel* (lb)	M2-.007	215.75	$2.00	$430.42
Primary	Copper wire, formvar, round	53.93	$4.84	$261.14
Secondary windings* (lb)	Aluminum strip, thickness range 0.02-0.045	23.83	$2.08	$49.64
Winding form & insulation* (lb)	Kraft insulating paper with diamond adhesive	4.34	$1.52	$6.94
Oil (gal)	-	37.6	$3.35	$125.93
Tank	-	1	$140.34	$140.34
Core clamp	-	1	$25.00	$25.00
Nameplate	-	1	$0.65	$0.65
Bushings	HV & LV	1	$58.00	$58.00
Misc. hardware	-	1	$16.00	$16.00
Scrap Factor			1.00%	$7.48
Total Material Cost				$1,122
Total Material Weight (lb)	748			

Labor item	**Hours**		**Rate**	**$ Total**
Lead dressing	0.5		51.52	$25.76
Inspection	0.1		51.52	$5.15
Tanking and impregnating	0.3		51.52	$15.46
Preliminary test	0.1		51.52	$5.15
Final test	0.15		51.52	$7.73
Pallet loading	0.5		51.52	$25.76
Marking and miscellaneous	0.35		51.52	$18.03
Winding the primary	0.19		51.52	$9.79
Winding the secondary	0.45		51.52	$23.18
Cutting, forming, and annealing	0.67		51.52	$34.52
Core assembly	0.25		51.52	$12.88
Handling and slitting factor (on material)			1.50%	$11.22
Total Labor	3.56		51.52	$194.65
Manufacturing Cost (Material + Labor)				$1,316
Factory Overhead (Materials only)		12.50%		$140
Shipping Cost (Based on Total Weight)		$0.22/lb		$210
Non-production Cost Markup		25.00%		$364
Manufacturer Selling Price**				$2,031

* Indicates those items to which the scrap factor (1.0%) and the handling and slitting factor (1.5% are applied.
** Price based on rounded estimations. The non-rounded price may vary slightly.

Figure 5.7.1 provides a summary of the costs contributing to the total selling price of the transformer from design line 1. For this design, approximately 57 percent of the final manufacturer selling price is direct material and scrap. Labor accounts for 9 percent of the price, factory overhead accounts for 7 percent, and together, shipping and non-production costs account for 27 percent.

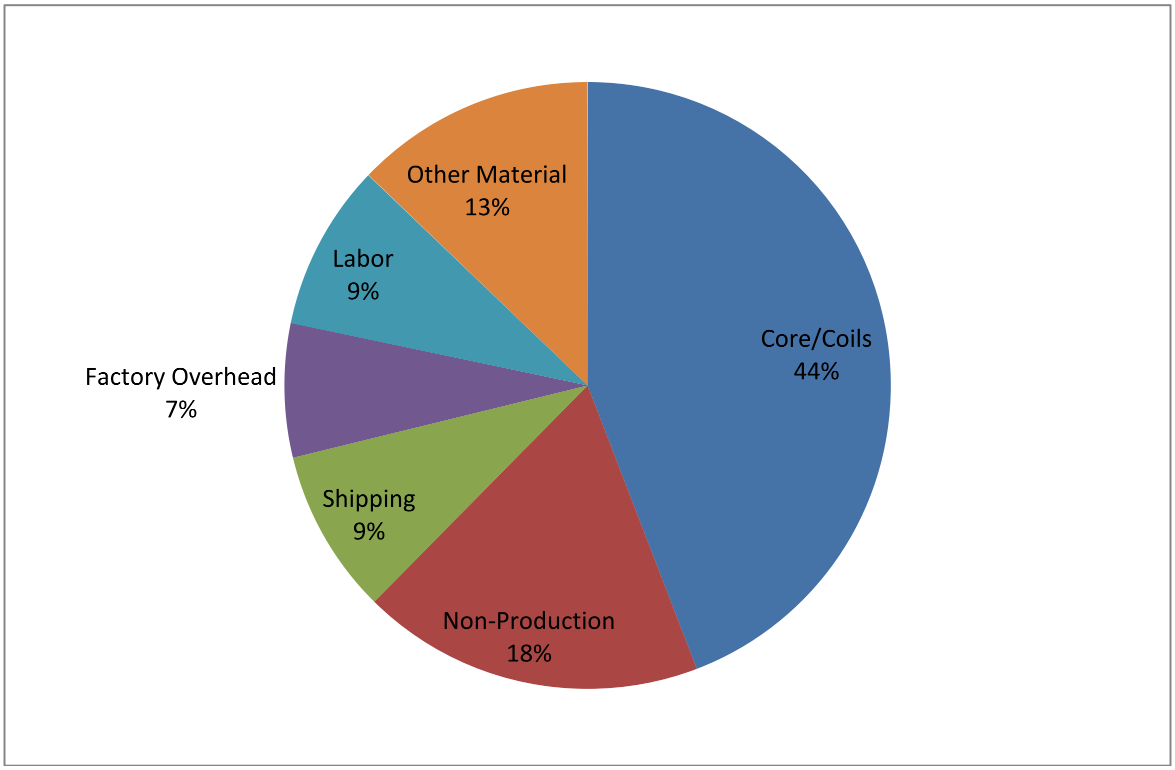

Figure 5.7.1 Manufacturer Selling Price Breakdown, Transformer from Design Line 1

5.7.2 Design Details Report for Transformer from Design Line 7

The following design report provides information on one of the several designs prepared to study the representative unit from design line 7. This is a 75kVA, three-phase, low-voltage, dry-type unit. The design shown here is for M6 full-mitered core steel with aluminum primary and secondary windings, and a $0.50A and $0.10B.

```
                    OPTIMIZED PROGRAM SERVICE
                 CLEVELAND OHIO            101800
                    2011- 8-26    15:59:25
DESIGN ID  DL7M6ALALFM
STRIP          3-PHASE TYPE TRANSFORMER
FREQUENCY    60.0            KVA RATING     74.94 @ 100.00% DUTY CYCLE
CORE    3.575" STRP  STACK    4.200          GRADE M 6    THICKNESS .0140
CORE WEIGHT:   CENTER   134.969       YOKES   143.368    TOTAL:   278.34
WINDOW:     3.600 X   11.250     EFF. AREA    14.489
WNDG FORM:INS. DIM.    3.700 X    4.325 THICKNESS   0.070 LENGTH   11.125
                      COIL SPECIFICATIONS
                      -------------------
WNDG             WIRE                LENGTH    MEAN TURNS   MARGIN       WT
---------------------------------------------------------------------------
S1   1X 2( 0.142X   0.568)  AL       55.20       21.37       0.250      10.328
P1          0.125X   0.375   AL      357.99       33.05       0.250      19.315

NUMBER OF COILS  3                  TOTAL BARE CONDUCTOR WEIGHT     88.931
                                    TOTAL INSULATION WEIGHT          0.196

WNDG  TURNS  LO TAP  HI TAP  LAYRS   T/L   LAYR INS    SEC. INS     BUILD
---------------------------------------------------------------------------
S1     31.0                   5      7.0  1( 0.0001)  1( 0.0070)   0.760
P1    124.0   112.0   130.0  5     26.0  1( 0.0000)  1( 0.0000)   0.650

                                             TOTAL BUILD(%)  86.11

WNDG               TAPS: TURNS( VOLTS)
---------------------------------------------------------------------------
P1      115.0(   445.00)   118.0(   457.00)   121.0(   468.00)
        127.0(   492.00)

WNDG    INTERNAL DUCTS( 80.00) %EFF  EXTERNAL DUCTS( 80.00) %EFF
---------------------------------------------------------------------
S1      2  0.563 X  0.563       END
P1      2  0.563 X  0.563       END          0.563 X  0.563      END

WNDG     INTERNAL DUCT LOCATIONS
---------------------------------------------------------------------
S1   1- 2; 3- 4;
P1   1- 2; 3- 4;

WNDG   INT. DUCT AREA  EXT. DUCT AREA  TOTAL DUCT AREA        (FANNED OUT)
---------------------------------------------------------------------------
S1         230.469          69.823          300.292
                                         Page 1
```

ELECTRICAL ANALYSIS

WNDG	FULL-LOAD VOLTS	TAP VOLTS LOW	HIGH	TEST KV	LOAD CURRENT	RESIST. @20 C.	CURRNT DENS.	%REG
P1	480.00 D	434.00	503.00	4.0	53.750	0.10388	1167.56	
S1	116.26 W	120.00 NLV		4.0	208.180	0.00462	1304.10	3.2

	F.L.	N.L.		
			DESTRUCTION FACTOR	1.147
FLUX DENS.	15.246	15.533	LEAKAGE INDUCTANCE MHYS	1.282
CORE LOSS	202.891	210.659	POWER FACTOR	1.000
COIL LOSS	2309.465	0.072	IMPEDANCE %	6.18
EXCIT. VA	600.529	571.745	EFFICIENCY %	96.76
EXCIT. CURR.	0.417	0.397	OPEN ALT. DUCT 3	0.00

AMBIENT TEMP.	20.00	NOMINAL LENGTH	21.525
TEMP RISE	129.63	NOMINAL DEPTH	13.555
OPERATING TEMP.	149.63	NOMINAL HEIGHT	18.400

WINDING:	S1	P1
TEMP RISE:	130.	129.

COND. I^2R LOSS = 2229.3467
COND. EDDY CURRENT LOSS = 13.2379
OTHER STRAY LOSS = 66.8804
K VALUE = 1.0000
% LOSS = 3.0000

WIRE WRAP PER COIL

WNDG	THICKNESS	WEIGHT
S1	0.00500	0.31917

TEMP. AT LOW TAP

S1	137.96
P1	137.62

% LOAD	% REG	% EFF	% IR	% IX	% IZ	CORE	LOAD LOSS	TEMP RISE
5	0.11	94.58	0.114	0.280	0.303	210.28	4.49	33.5
10	0.22	97.06	0.221	0.542	0.585	209.91	17.30	34.1
15	0.33	97.84	0.329	0.806	0.870	209.85	38.60	35.0
20	0.45	98.18	0.439	1.070	1.157	209.57	68.61	36.2
25	0.56	98.34	0.551	1.335	1.444	209.29	107.56	37.8
30	0.68	98.40	0.665	1.601	1.733	208.99	155.81	39.8
35	0.80	98.41	0.782	1.867	2.024	208.69	213.77	42.2
50	1.20	98.27	1.157	2.670	2.910	207.68	451.66	52.1
60	1.50	98.08	1.433	3.210	3.516	207.00	671.34	61.2
65	1.66	97.97	1.582	3.481	3.824	206.61	802.74	66.7
75	2.01	97.70	1.907	4.028	4.456	205.74	1116.07	79.8
80	2.21	97.55	2.085	4.303	4.781	205.27	1301.91	87.5
100	3.17	96.76	2.959	5.421	6.176	202.89	2309.47	129.6
125	5.07	95.14	4.699	6.887	8.337	198.66	4588.33	223.5

Page 2

Table 5.7.2 provides the bill of materials which was calculated from the OPS design details report. This bill of materials uses the raw material prices given in this chapter for fixed and variable materials used in building the transformer. These materials are then marked-up at the bottom of the table to arrive at the manufacturer’s selling price.

Table 5.7.2 Bill of Materials for Transformer from Design Line 7

Bill of Materials and Labor for low-voltage, dry-type, three-phase, 75kVA

A$ Input	$0.50				
B$ Input	$0.10				
Efficiency at	98.12%				
Material Item	**Type**		**Quantity**	**$ Each**	**$ Total**
Core Steel* (lb)	M6-.014		301.33	$1.46	$438.44
Primary winding* (lb)	Aluminum wire, rectangular, 0.1x0.2, Nomex		54.6	$2.97	$162.33
Secondary windings* (lb)	Aluminum wire, rectangular, 0.1x0.2, Nomex		30.9	$2.97	$91.88
Winding form & insulation* (lb)	Nomex insulation		0.21	$24.50	$36.83
Enclosure	14-gauge steel		1	$131.82	$131.82
Core clamp	-		1	$19.00	$19.00
Duct spacers (ft., drop 2/3)	-		23.56	$0.32	$7.54
Nameplate	-		1	$0.65	$0.65
LV Buss Bar (ft.)	-		7	$1.50	$10.50
HV Terminal	-		3	$9.00	$27.00
Impregnation	-		1.18	$22.55	$26.53
Misc. hardware	-		1	$7.00	$7.00
Scrap Factor				1.00%	$7.29
Total Material Cost					$967
Total Material Weight (lb)		502			
Labor item		**Hours**		**Rate**	**$ Total**
Lead dressing		0.25		51.52	$12.88
Inspection		0.05		51.52	$2.58
Preliminary test		0.05		51.52	$2.58
Final test		0.1		51.52	$5.15
Packing		0.2		51.52	$10.30
Marking and miscellaneous		0.2		51.52	$10.30
Enclosure manufacturing		1.5		51.52	$77.28
Winding the primary		0.59		51.52	$30.40
Winding the secondary		1.02		51.52	$52.55
Core stacking		1.35		51.52	$69.55
Core assembly		1		51.52	$51.52
Handling and slitting factor (on material)				1.50%	$10.94
Total Labor		6.31		51.52	$336
Manufacturing Cost (Material + Labor)					$1,303
Factory Overhead (Materials only)			12.50%		$121
Shipping Cost (Based on Total Weight)			$0.22/lb		$141
Non-production Cost Markup			25.00%		$356
Manufacturer Selling Price**					$1,921

* Indicates those items to which the scrap factor (1.0%) and the handling and slitting factor (1.5% are applied.
** Price based on rounded estimations. The non-rounded price may vary slightly.

Figure 5.7.2 provides a summary of the costs contributing to the total selling price of the transformer from design line 7. For this design, approximately 50 percent of the final manufacturer selling price is direct material and scrap. Labor accounts for 18 percent of the price, factory overhead accounts for 6 percent, and together, shipping and non-production costs account for 26 percent.

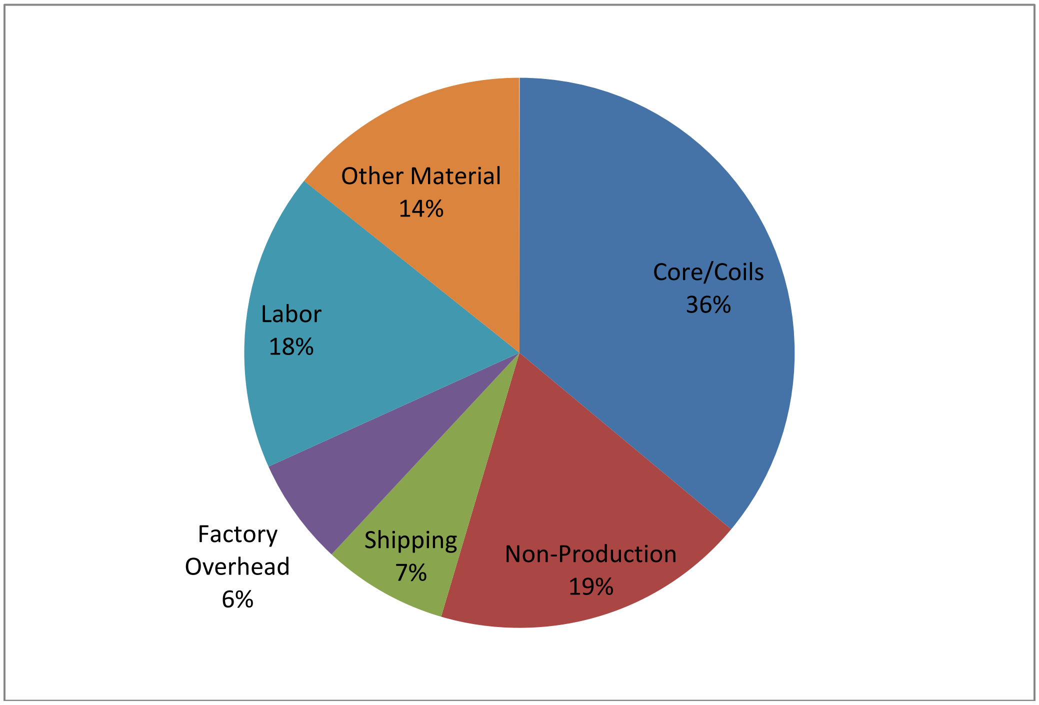

Figure 5.7.2 Manufacturer Selling Price Breakdown, Transformer from Design Line 7

5.7.3 Design Details Report for Transformer from Design Line 12

The following design report provides information on one of several designs prepared to study the representative unit from design line 12. This is a 1500kVA, three-phase, medium-voltage, dry-type unit at 95kV BIL. The design shown here is for M3 step-lap mitered core steel with aluminum primary and secondary windings, and a \$1.50A and \$0.30B. This is a different design option combination than the original design selected for the preliminary analysis, which was for M4 core steel with copper primary and aluminum secondary windings, and a \$1.50A and \$0.30B.

OUTPUT

OPTIMIZED PROGRAM SERVICE

CLEVELAND OHIO 101800

2011- 8-29 17:15:25

DESIGN ID DL12M3SAA

STRIP CRUC 3-PHASE TYPE TRANSFORMER

FREQUENCY 60.0 MVA RATING 1.50 @ 100.00% DUTY CYCLE

CORE 9.450" CRUC STACK 9.300 GRADE M 3 THICKNESS .0090

WINDOW: 18.250 X 59.875 EFF. AREA 65.976 WEIGHT 5632.579

WNDG FORM:INS. DIM. 9.925 X 9.925 THICKNESS 0.156 LENGTH 57.875

COIL SPECIFICATIONS

WNDG	WIRE		LENGTH	MEAN TURNS	MARGIN	WT
S1	2X 1(0.020X 47.875)	AL	55.95	41.96	5.000	125.552
P1	1X 2(0.080X 0.275)	AL	4293.76	68.15	5.750	212.983

NUMBER OF COILS 3 TOTAL BARE CONDUCTOR WEIGHT 1015.605
TOTAL INSULATION WEIGHT 127.925

WNDG	TURNS	LO TAP	HI TAP	LAYRS	T/L	LAYR INS	SEC. INS	BUILD
S1	16.0			16	1.0	1(0.0100)	1(0.3000)	3.040
P1	720.0	684.0	756.0	16	1.0	1(0.0000)	1(0.0000)	1.472

TOTAL BUILD(%) 73.49

WNDG	TAPS: TURNS(VOLTS)	
P1	702.0(12158.25)	738.0(12781.75)

DISK INFORMATION

WNDG	DISK	WIDTH	VOLTS/DISK	BREAK	TAPS	SPACE
P1	48	0.599	272.781	0.375	2(0.38)	44(0.375)

WNDG	INTERNAL DUCTS(90.00) %EFF		EXTERNAL DUCTS(90.00) %EFF	
S1	3 0.750 X 0.750	FULL		
P1			2 0.750 X 0.750	FULL

WNDG	INTERNAL DUCT LOCATIONS
S1	3- 4; 7- 8;11-12;
P1	

Page 1

```
                                         OUTPUT
                                      (FANNED OUT)
WNDG   INT. DUCT AREA  EXT. DUCT AREA  TOTAL DUCT AREA  WPS       RISE
------------------------------------------------------------------------
S1        8490.855        2044.772       10535.628                114.65
P1           0.000        3273.531        7117.251                 80.54

DUCT UNDER BARRIER    0.7500
DUCT OVER  BARRIER    0.7500


                           ELECTRICAL ANALYSIS
                           -------------------

    FULL-LOAD    TAP VOLTS        TEST    LOAD    RESIST.  CURRNT
WNDG   VOLTS     LOW       HIGH     KV   CURRENT   @20 C.    DENS.  %REG
------------------------------------------------------------------------
P1   12470.00 D   11846.50 13093.50 18.0   40.556    1.35526  958.24
S1     273.53 W     277.11 NLV       4.0 1804.000    0.00039  942.12  1.3


                  F.L.       N.L.   DESTRUCTION FACTOR          1.060
FLUX DENS.       15.129     15.267  LEAKAGE INDUCTANCE MHYS    61.210
CORE LOSS      2393.233   2453.828  POWER FACTOR                1.000
COIL LOSS     15626.172      0.068  IMPEDANCE %                 7.57
EXCIT. VA      3923.189   4087.619  EFFICIENCY %               98.81
EXCIT. CURR.      0.105      0.109  OPEN ALT. DUCT 3            0.00

AMBIENT TEMP.     20.00                NOMINAL LENGTH      83.100
TEMP.RISE        114.65                NOMINAL  DEPTH      23.314
OPERATING TEMP.  134.65                NOMINAL HEIGHT      78.775


     CRUCIFORM PLATE WIDTHS

       W1     W2     W3     W4     W5
     9.45    8.38    7.00    5.25    3.12

     STACK HEIGHTS

       H1     H2     H3     H4     H5
     3.12    1.00    0.88    0.70    0.51

     RESULTANT GROSS AREA:          69.084   CIRCLE AREA FILL: % 88.8

     MIN.  WINDING FORM INSIDE DIAMETER:   9.953

 WINDING:        S1    P1
 TEMP RISE:    115.   81.

        2
 COND. I R LOSS           =  14940.9639
 COND. EDDY CURRENT LOSS  =     87.5699
 OTHER STRAY LOSS         =    597.6385
 K VALUE                  =      1.0000
 % LOSS                   =      4.0000

  WIRE WRAP PER COIL
WNDG   THICKNESS   WEIGHT
-------------------------
P1     0.00600   15.46618

TEMP.  AT LOW TAP   WPS    RISE
                                      Page 2
```

OUTPUT

S1	114.65	84.18
P1	84.18	114.65

AT REFERENCE TEMP. 170.0^{o}

COIL LOSS = 17166.209
IMPEDANCE % = 7.591

% LOAD	% REG	% EFF	% IR	% IX	% IZ	CORE	LOAD LOSS	TEMP RISE
5	0.04	96.80	0.039	0.384	0.386	2451.43	30.83	29.9
10	0.08	98.32	0.077	0.755	0.759	2449.14	121.09	30.7
15	0.12	98.81	0.115	1.126	1.132	2446.77	271.97	32.1
20	0.17	99.03	0.154	1.498	1.506	2444.31	485.20	33.9
25	0.21	99.15	0.194	1.870	1.880	2441.76	763.12	36.2
30	0.26	99.22	0.234	2.243	2.255	2439.12	1108.56	39.0
35	0.31	99.25	0.276	2.616	2.630	2436.40	1524.84	42.2
50	0.48	99.25	0.411	3.737	3.759	2427.71	3238.50	54.0
60	0.61	99.20	0.510	4.486	4.515	2421.48	4815.02	63.7
65	0.68	99.17	0.562	4.862	4.894	2418.24	5749.49	69.1
75	0.84	99.09	0.673	5.614	5.654	2411.49	7941.14	80.6
80	0.92	99.04	0.732	5.991	6.035	2407.99	9211.49	86.9
100	1.29	98.81	0.993	7.505	7.571	2393.13	15626.19	114.6
125	1.86	98.44	1.387	9.415	9.517	2372.68	27268.54	155.3

Table 5.7.3 provides the bill of materials which was calculated from the OPS design details report. This bill of materials uses the raw material prices given in this chapter for fixed and variable materials used in building the transformer. These materials are then marked-up at the bottom of the table to arrive at the manufacturer's selling price.

Table 5.7.3 Bill of Materials for Transformer from Design Line 12

Bill of Materials and Labor for medium-voltage, dry-type, three-phase, 1500kVA					
A$ Input	$1.50				
B$ Input	$0.30				
Efficiency at	99.14%				
Material Item	**Type**		**Quantity**	**$ Each**	**$ Total**
Core Steel* (lb)	M4-.011		5,738.61	$1.88	$10,760
Primary winding* (lb)	Copper wire, rectangular, 0.1x0.2, Nomex		622.58	$2.97	$1,851
Secondary windings* (lb)	Aluminum strip, thickness range 0.02 - 0.045		362.33	$2.08	$755
Winding form & insulation* (lb)	Nomex insulation		134	$24.50	$4,153
Enclosure	12-gauge steel		1	$820.43	$820
Core clamp	-		1	$125.00	$125
Duct spacers	-		1,589.03	$0.56	$890
Nameplate	-		1	$0.65	$0.65
LV Buss Bar (ft.)	-		16	$12.00	$192
HV tap board	-		3	$9.00	$27
HV Terminals	-		1	$135.00	$135
Winding combs	-		96.11	$12.34	$1,186
Impregnation	-		32.89	$22.55	$742
Misc. hardware	-		1	$54.00	$54
Scrap Factor				1.00%	$606
Total Material Cost					$22,296
Total Material Weight (lb)		8,055			
Labor item		**Hours**		**Rate**	**$ Total**
Lead dressing		1		51.52	$52
Inspection		0.25		51.52	$13
Preliminary test		0.5		51.52	$26
Final test		0.75		51.52	$39
Packing		2		51.52	$103
Marking and miscellaneous		2.2		51.52	$113
Enclosure manufacturing		8		51.52	$412
Winding the primary		28.35		51.52	$1,461
Winding the secondary		3.6		51.52	$185
Core stacking		6.04		51.52	$311
Core assembly		6		51.52	$309
Handling and slitting factor (on material)				1.50%	$263
Total Labor		58.7		51.52	$3,286
Manufacturing Cost (Material + Labor)					$25,582
Factory Overhead (Materials only)			12.50%		$2,787
Shipping Cost (Based on Total Weight)			$0.22/lb		$2,265
Non-production Cost Markup			25.00%		$7,092
Manufacturer Selling Price***					$37,727

* Indicates those items to which the scrap factor (1.0%) and the handling and slitting factor (1.5% are applied.
** Additional scrap on core due to mitering process.
*** Price based on rounded estimations. The non-rounded price may vary slightly.

Figure 5.7.3 Manufacturer Selling Price Breakdown, Transformer from Design Line 12 provides a summary of the costs contributing to the total selling price of the transformer from design line 12. For this design, approximately 59 percent of the final manufacturer selling price is direct material and scrap. Labor accounts for 9 percent of the price, factory overhead accounts for 7 percent, and together, shipping and non-production costs account for 25 percent.

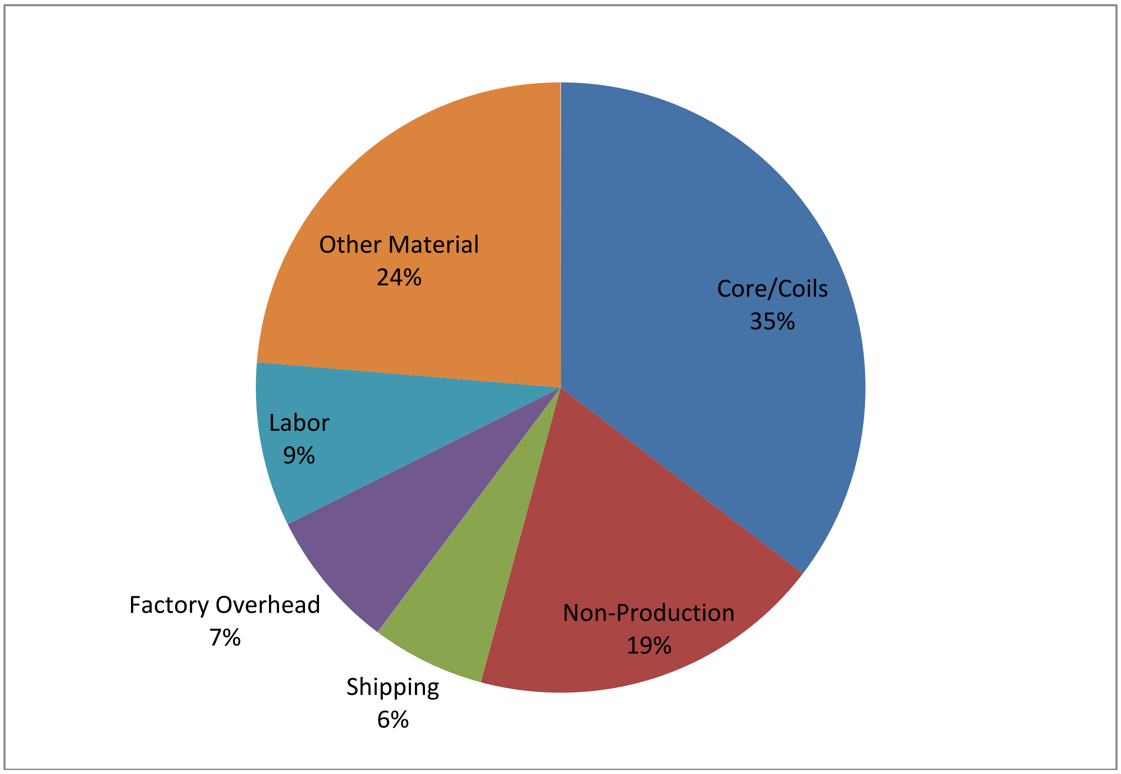

Figure 5.7.3 Manufacturer Selling Price Breakdown, Transformer from Design Line 12

CHAPTER 6. MARKUPS FOR EQUIPMENT PRICE DETERMINATION

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CHAPTER 6. MARKUPS FOR EQUIPMENT PRICE DETERMINATION

6.1 INTRODUCTION

This chapter of the technical support document (TSD) presents DOE's method for deriving transformer prices. The objective of the equipment price determination is to estimate the price paid by the customer or purchaser for an installed transformer. Purchase price and installation cost are necessary inputs to the life-cycle cost (LCC) and payback period (PBP) analyses. Chapter 8 presents the LCC calculations; section 8.2.1 describes how the LCC uses purchase price and installation cost as inputs.

Purchase prices for distribution transformers are not generally known. Transformers are specialty items, often custom-built with unlisted prices. The engineering analysis (Chapter 5) provided the manufacturer selling prices for the units included in the LCC analysis. DOE derived a set of prices for each transformer design produced by the engineering analysis by applying markups to the manufacturer selling price in the form of markup equations. These markups represent all the costs associated with bringing a manufactured transformer into service as an installed piece of electrical equipment at a customer's site.

6.2 OVERVIEW OF MARKUP EQUATIONS

Depending on the purchasing environment, DOE used different markup equations to capture the various markups in the supply chain between the manufacturer and the customer. For example, electric utilities (except for the rural electric cooperatives) typically purchase liquid-immersed transformers through manufacturer representatives or distributors. The manufacturer selling price plus the distributor markup is generally the utilities' price for transformers. Dry-type transformers go through several additional marketing or handling steps before they are installed by the end-use purchaser.

Liquid-type distribution transformers have a seven percent markup, accounting for distributor markup.[1] This markup is eliminated for a fraction of cases to account for liquid-immersed transformer sales that are from manufacturers directly to utilities. The fraction of cases is determined by the amount of electricity reportedly sold by IOUs in EIA's Form 861, is 82%.

The manufacturer selling prices for dry-type transformers include two price markups: a distributor markup of 15 percent and 26 percent for low and medium-voltage dry-type transformers respectively, and a contractor materials markup of 10 percent and 16 percent for low and medium-voltage dry-type transformers respectively. DOE based these markups (expressed as average multipliers) on *RS Means Electrical Cost Data Online 2011*[2] and stake holder input respectively for low and medium-voltage dry-type transformers. The distributor markup converts the manufacturer selling price to the distributor price and the price paid by the electrical contractor. This distributor markup covers the costs of the distribution business, including sales labor, warehousing, overhead, and profit. Then the contractor applies a markup to the distributor selling price to cover contractor overhead and profit.

For both liquid-immersed and dry-type transformers, DOE added sales tax, an installation labor and equipment markup, and installation costs. In the previous distribution transformer rulemaking DOE analyzed shipping costs as one of the markups used to determine installed equipment price. In this Preliminary Analysis the markups for shipping costs have been moved into the engineering analysis; this is described in greater detail in chapter 5. Using *RS Means Electrical Cost Data Online 2011,* DOE estimated a contractor markup of 1.10, which is used to convert the distributor selling price to a contractor price. Then the installation cost is added as the cost of labor, equipment, and materials (other than the transformer itself) needed to install a distribution transformer. Finally, by weighting the sales tax for each individual State by its population, DOE calculated a national weighted average sales tax of 6.9 percent.[3] DOE developed several empirical equations for estimating installation costs by following these steps mentioned above.

6.3 ESTIMATION OF INSTALLED PRICE

In order to estimate the installed price for distributor transformers, DOE applied the following equation, which describes the steps in the distribution channel of transformers:

$$Installed\ Price = M_{tax} \times \{M_{L\&E} \times L\&E + M_{Mat} \times [M_{Dist} \times ManPrice]\}$$

Where:

Installed_Price	=	the final installed price of the transformer (2010$),
M_{tax}	=	the factor that accounts for sales tax, estimated to be 1.069,[3]
$M_{L\&E}$	=	the factor that accounts for the markup on direct installation labor and equipment costs,
$L\&E$	=	the installation, direct labor, and equipment costs (2010$), adjusted to 2010$ using the gross domestic product (GDP) price deflator from the *U.S. Bureau of Economic Analysis (BEA)*.[4]
M_{Mat}	=	the factor that accounts for the contractor markup on the purchase of the transformer from the distributor,
M_{Dist}	=	the average distributor markup factor, and
ManPrice	=	the manufacturer's selling price (2010$).

DOE estimated markups on transformers by fitting a linear cost function to the *RS Means* electrical cost data (see section 6.3.3). The *RS Means* data break down the total installed cost for transformers in terms of four cost components:

1. materials: the unit material cost, which includes mounting hardware, but not overhead or profit;

2. labor: labor cost required for installation, including unloading, uncrating, hauling within 200 feet of the loading dock, setting in place, connecting to the distribution network, and testing;

3. equipment: equipment rentals necessary for completion of the installation; and

4. overhead and profit (O&P): installation overhead and profit expenses for the contractor (for dry-type transformers only).

RS Means lists the first three cost components separately and then has an additional column listing the total costs including O&P. As defined by *RS Means*, this figure is the sum of the bare material cost plus 10 percent for profit; the bare labor cost plus total overhead and profit; and the bare equipment cost plus 10 percent for profit.

6.3.1 Estimation of Pole Replacement Costs

In evaluating design options and the impact of potential standard levels, DOE examined the potential for new standards for distribution transformers to lessen the utility or performance of these products. Stakeholders mentioned in their comments to DOE that the more efficient transformers that are heavier could have lessened utility due to impacts on utility pole requirements for overhead transformers. DOE estimated the additional installation costs, based on cost data provided by stakeholders, to mount the single-phase, pole-mounted, liquid-immersed transformers whose designs would require an upgrade to the pole due to increased transformer weight.

DOE included a pole-replacement cost function as a part of the installation cost equation for DL2, which covers pole-mounted transformers. In general, as transformers are redesigned to reach higher efficiency, the weight and size also increase. The degree of weight increase depends on how the design is modified to improve efficiency. For pole-mounted transformers, represented by design line (DL) 2, the increased weight may lead to situations where the pole needs to be replaced to support the additional weight of the transformer. This in turn leads to an increase in the installation cost. To account for this effect in the analysis, three steps are needed:

The first step is to determine whether the pole needs to be changed. This depends on the weight of the transformer in the base case compared to the weight of the transformer under a proposed efficiency level, and on assumptions about the load-bearing capacity of the pole. In the LCC calculation, it is assumed that a pole change-out will only be necessary if the weight increase is larger than 15 percent and greater than 150 lbs of the weight of the baseline unit. Utility poles are primarily made of wood. Both ANSI and NESC provide guidelines on how to estimate the strength of a pole based on the tree species, pole circumference and other factors. Natural variability in wood growth leads to a high degree of variability in strength values across a given pole class. Thus, NESC also provides guidelines on reliability, which result in an acceptable probability that a given pole will exceed the minimal required design strength. Because poles are sized to cope with large wind stresses and potential accumulation of snow and ice, this results in "over-sizing" of the pole relative to the load by a factor of two to four.

Because of this "over-sizing" DOE limited the total fraction of pole replacements to 25 percent of the total population.

The second step is to determine the cost of a pole change-out. DOE used data taken from the RSMeans Building Construction Cost database on utility pole replacement and crew costs. Based on this information, a triangular distribution was used to estimate pole change-out costs, with a lower limit at $2,025 and an upper limit at $5,999. Utility poles have a finite life-time, so that pole change-out due to increased transformer weight should be counted as an early replacement of the pole; *i.e.* it is not correct to attribute the full cost of pole replacement to the transformer purchase. Equivalently, if a pole is changed out when a transformer is replaced, it will have a longer lifetime relative to the pole it replaces, which offsets some of the cost of the pole installation. To account for this affect, pole installation costs are multiplied by a factor *n/pole-lifetime*, which approximately represents the value of the additional years of life. The parameter *n* is chosen from a flat distribution between 1 and the pole lifetime, which is assumed to be 30 years.[a]

6.3.2 Impact of Increased Transformer Weight on Installation Costs

DOE derived the weight-versus-capacity relationship for typical transformers from the design data produced by the engineering analysis. It used the weight-versus-capacity relationship to estimate the transformer weight corresponding to the transformer costs reported in *RS Means*. DOE estimated a scaling relationship between transformer weight and direct installation labor and equipment costs by fitting the correlation between weight and installation costs to a power- law equation.

The method for deriving the weight-versus- capacity relationship uses a typical transformer weight from the engineering analysis. DOE defined the *typical weight* as the minimum weight plus 20 percent times the weight range, where the weight range is the difference between the minimum and maximum transformer weight for the selected design.

From these data, DOE obtained the following power-law relationship for transformer weight as a function of capacity and basic impulse insulation level (BIL) rating:

$$Weight = 17.31 \times kVA^{0.52} \times BIL^{0.44}$$

Where:

$Weight$ = the weight of the transformer (lbs),

---

[a] As the LCC represents the costs associated with purchase of a single transformer, to account for multiple transformers mounted on a single pole, the pole cost should also be divided by a factor representing the average number of transformers per pole. No data is currently available on the fraction of poles that have more than one transformer, so this factor is not included.

kVA = the capacity of the transformer (kVA), and
BIL = the BIL rating of the transformer (kV).

Although *RS Means* does not provide transformer weights, it does provide transformer capacity and primary voltage. DOE estimated weight from capacity and BIL, which it estimated using primary voltage. DOE then compared the weight to the direct installation costs from the labor and equipment to obtain a power-law relationship.

The following regression performed was the installation direct labor and equipment costs as a function of transformer weight. Data analyzed included all 67 distribution transformer kVA ratings spanning the three *RS Means* electrical equipment categories: "dry type transformer", "oil-filled transformer", and "transformer, liquid-filled". The resulting correlation equation is:

$$L\&E = 38.69 \times Weight^{0.53}$$

Where:

$L\&E$ = the installation, direct labor, and equipment costs (2010$),
$Weight$ = the weight of the transformer (lbs).

6.3.3 Estimation of Markups

DOE performed a regression to disaggregate the overhead and profit associated with installation labor and equipment rental from the overhead and profit associated with the transformer (material) cost. The regression equation is:

$$Total\ Costs\ Including\ O\&P = \alpha + \beta \times Mat + \gamma \times L\&E$$

Where:

Total Costs Including O&P = the sum of all bare costs plus overhead and profit expense (2010$),
Mat = the material cost (transformer and hardware) (2010$), and
L&E = the direct labor and equipment costs of installation (2010$).

After running the regression above, DOE found that the estimated coefficient for the constant term is not significantly different from zero; therefore DOE reran the regression without the constant term. The resulting equation is:

$$Total\ Costs\ Including\ O\&P = 1.10 \times Mat + 1.47 \times L\&E$$

The interpretation of the coefficient of material costs is that when material costs increase $1, then the total costs including O&P should be expected to increase $1.10 while holding the other variable constant. Likewise, a $1 increase in the direct labor and equipment costs will lead to a $1.47 increase in the total costs including O&P while holding the other variable constant. These two figures were used to allocate overhead and profit expenses to a markup on the distribution price and a separate markup on the direct labor and equipment costs for the installation.

6.3.4 Dry-Type Transformer Installed Price Equation

For dry-type transformers, the result of these analytical steps is a total installed cost equation as a function of the manufacturer selling price, and direct labor and equipment costs, using those markups estimated in section 6.3.3:

$$Installed\ Price = M_{tax} \times \{M_{L\&E} \times L\&E + M_{Mat} \times [M_{Dist} \times ManPrice]\}$$

Where:

Installed_Price	=	the final installed price of the transformer (2010$),
M_{tax}	=	the factor that accounts for sales tax, estimated as 1.069,
$M_{L\&E}$	=	the factor that accounts for the markup on direct installation labor and equipment costs, estimated as 1.47,
L&E	=	the installation, direct labor, and equipment costs (2010$), adjusted to 2010$ using the GDP price deflator from *BEA*,
M_{Mat}	=	the factor that accounts for the contractor markup on the purchase of the transformer from the distributor, estimated as 1.10 for low-voltage dry-type and 1.16 for medium-voltage dry-type,
M_{Dist}	=	the average distributor markup factor, estimated as 1.15[1] for low-voltage dry-type, and 1.26 for medium-voltage dry-type, and
ManPrice	=	the manufacturer's selling price (2010$).

DOE applied the installed cost equation by using the manufacturer price and weight from the engineering analysis. For example, according to the engineering analysis, a DL8 (low-voltage, three-phase, 750 kVA) transformer model with $1,698.55 of L&E costs listed in *RS Means* has a minimum manufacturer price of $4,235.47. For this particular transformer, DOE estimated the lower bound of the installed cost to be $8,396.72, where $2,669.15 is the installation cost and $5,727.57 is the sum of the transformer retail price, sales tax, and markups.

6.3.5 Liquid-Immersed Transformer Installed Price Equation

The installed price calculation for liquid-immersed transformers differs from that for dry-type transformers in that the distributor markup used in the equation is 1.07 instead of 1.15 and DOE removed the contractor markup from the equation based on the previous rulemaking.[1] DOE added a new distribution channel to represent the direct sale of transformers to utilities, which account for approximately 81 percent of liquid-immersed transformer shipments. The fraction of utilities that purchase directly manufacturers is based on the percent of electricity sales by independently owned utilities in the *EIA's Form 861*[1] database. This sales channel removes a distributor markup. The inclusion of this channel reduces the overall markup for liquid-immersed transformers.

$$Installed\ Price = M_{tax} \times \{M_{L\&E} \times L\&E + [M_{Dist} \times ManPrice]\}$$

Where:

Installed_Price	=	the final installed price of the transformer (2011$),
M_{tax}	=	the factor that accounts for sales tax, estimated as 1.069,
$M_{L\&E}$	=	the factor that accounts for the markup on direct installation labor and equipment costs, estimated as 1.47,
L&E	=	the installation, direct labor, and equipment costs (2010$), adjusted to 2011$ using the GDP price deflator from *BEA*,
M_{Dist}	=	the average distributor markup factor, estimated as 1.07, and
ManPrice	=	the manufacturer's selling price (2011$).

As with the dry-type transformers, DOE applied the installed cost equation by using the manufacturer price and weight from the engineering analysis. For example, according to the engineering analysis, a DL4 (medium-voltage, three-phase, 225 kVA) transformer model with $2,309.64 of L&E costs listed in *RS Means* has a minimum manufacturer price of $5,305.36. For this particular transformer, DOE estimated the lower bound of the installed cost to be $9,697.87, where $3,629.44 is the installation cost and $6,068.43 is the sum of the transformer retail price, sales tax, and markups.

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CHAPTER 7. ENERGY USE AND END-USE LOAD CHARACTERIZATION

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CHAPTER 7. ENERGY USE AND END-USE LOAD CHARACTERIZATION

7.1 INTRODUCTION

The U.S. Department of Energy (DOE) characterized energy use and end-use load for distribution transformers. Estimates of energy use enabled evaluation of energy savings associated with operating distribution transformers at various efficiency levels. The characterization of end-use load enabled evaluation of the impact of load on electricity demand. DOE's analysis produced a distribution of results for a range of installation types, operating conditions, and climate locations intended to represent the diversity of the application and performance of distribution transformers.

Distribution transformers consume energy via both no-load losses and load losses. No-load losses, which are constant over time, occur whenever a transformer is energized by power lines. Load losses vary with the square of the load the transformer is serving. There are two types of distribution transformers: liquid-immersed and dry. Liquid-immersed transformers are owned primarily by electric utilities. Utilities pay marginal costs for the power used to generate electricity, costs that can vary by the hour. DOE therefore developed a statistical simulation model to estimate the hourly load characteristics of liquid-immersed transformers and to develop a correlation between hourly loads and system loads. Dry-type transformers are owned by commercial and industrial (C&I) establishments, which are billed for electricity according to a tariff. For dry-type distribution transformers, DOE used empirical estimates of load characteristics to estimate monthly average (root mean square) loads and peak coincident loads. This chapter first describes transformer losses, then presents the details of the load characterization models DOE developed for liquid-immersed and dry-type transformers.

The no-load losses experienced by distribution transformers arise primarily from the switching of the magnetic field in the transformer core material. Those losses, which are roughly constant, occur whenever the transformer is energized (*i.e.*, connected to a live power line). Load losses, also known as resistance or I^2R losses, vary in response to the changing load on the transformer. Load losses are proportional to the load squared plus a relatively small temperature correction (<15 percent for loads less than the rated load). DOE uses the following formula, which incorporates both load and no-load losses, to estimate the energy used by a distribution transformer.

$$\boldsymbol{E_T} = \in_{\boldsymbol{NLL}} + \boldsymbol{E} + \in_{\boldsymbol{LL}} \left(\boldsymbol{E} / \boldsymbol{E_{max}} \right)^2$$

Where:

$\in_{NLL}$	=	the no-load loss rate,
E	=	the total energy used by a transformer experiencing instantaneous load,
$\in_{LL}$	=	the load loss rate, and
E_{max}	=	the expected peak load on the transformer.

The characteristics of transformer loads required for DOE's life-cycle cost (LCC) analysis also depend on the way the user's electricity is priced. Because approximately 95 percent of liquid-immersed transformers are owned by electric utilities, the appropriate electricity price for those transformers is the cost of production, which varies hourly. For those types of transformers, DOE's analysis was based on hourly load and price data. The electricity use of dry-type transformers, which are installed primarily in commercial and industrial buildings, is billed monthly. For those types of transformers, DOE developed an analysis based on monthly, building-level data.

7.2 LOAD MODEL FOR LIQUID-IMMERSED TRANSFORMERS

This section describes the hourly load model DOE developed in support of its LCC analysis for liquid-immersed transformers.

The operating cost savings associated with improved transformer efficiency are equal to the energy savings (reduction in losses) times the price of energy. For liquid-immersed transformers, the appropriate price is the marginal production cost of electricity. This production cost, which varies regionally and temporally, correlates strongly with the magnitude of the total electric system load. Because the load on an individual transformer also correlates somewhat with system load, there is some correlation between transformer load losses and the price of electricity. To capture those correlations, DOE developed a statistical model based on hourly electric system load data, marginal hourly electric system-production prices, a joint probability distribution between transformer and system load levels. The steps in the operation of the hourly load simulation program are described below.

1. The program selects a transformer owner from a list of utilities that own electricity distribution equipment.
2. The program determines a sample weight for the selected utility, based on total kilowatt-hours sold.
3. The program selects the customer type (residential or C&I) served by the transformer and the appropriate weight for that customer type. The weight is assigned based on the fraction of that utility's electricity sales to that customer type.
4. The program goes through a loop to calculate the hourly transformer loads and system marginal prices for the selected transformer. System prices, and their dependence on system load, are determined from historical data. Prices differ by region and season. The transformer load is estimated based on a joint distribution function that predicts the transformer load for a given system load. The individual steps in the loop are as follows.
    a. Choose a system load value from the system load distribution function.
    b. Estimate the system price for that system load.
    c. Estimate the transformer load for that system load.
5. For each simulation, the program provides output to be used in calculating the LCC. The output includes a transformer identification (ID), the utility ID, customer category, and transformer load losses and operating costs.

7.2.1 Inputs to Hourly Load Model

The following sections describe the inputs used in simulating the hourly load for liquid-immersed distribution transformers.

7.2.1.1 Utility Information

The LCC analysis for liquid-immersed transformers uses two types of information related to electric utilities. The first is drawn from the Energy Information Administration's (EIA's) Form 861 database.[1] Form 861 provides, through its Form 2, the annual sales in megawatt-hours for each utility to the residential, commercial, and industrial sectors. Form 861's Form 4 lists all the utilities that own electricity distribution equipment and the county in which that equipment is located. Based on those data, DOE created a list of utilities that own transformers and assigned a weight to each based on the electricity sales of that utility.

The second type of utility information used in the LCC analysis is hourly system loads and prices. DOE developed regional system loads and prices for the set of regions defined in the EIA National Energy Modeling System (NEMS) Electricity Market Module (EMM).[2] The regions represent both national reliability regions and, where they exist, integrated wholesale electricity markets, as illustrated in Figure 7.2.1. Each region in turn comprises a number of electric utility control area operators (CAOs), some of which may also be utility companies. DOE obtained hourly load and system lambda data (for regions without wholesale markets) or day-ahead market price data (for market regions) from the Federal Energy Regulatory Commission (FERC) Form 714 database.[3] DOE aggregated the hourly data to produce regional time series for the EMM regions. Appendix 7-B contains the list of entities, along with their designated CAO and EMM regions, for which DOE obtained the FERC data used to create the hourly time series.

Figure 7.2.1 Electricity Market Module Regions in NEMS

The numbered regions in Figure 7.2.1 are described in Table 7.2.1.

Table 7.2.1 Definition of EMM Regions in NEMS

Index	Abbreviation	Definition
1	ECAR	East Central Area Reliability Coordination Agreement
2	ERCOT	Electric Reliability Council of Texas
3	MAAC	Mid-Atlantic Area Council
4	MAIN	Mid-America Interconnected Network
5	MAPP	Mid-Continent Area Power Pool
6	NY	New York
7	NE	New England
8	FL	Florida Reliability Coordinating Council
9	SERC	Southeastern Electric Reliability Council
10	SPP	Southwest Power Pool
11	NPP	Northwest Power Pool
12	RA	Rocky Mountain Power Area
13	CA	California

7.2.1.2 Initial Peak Transformer Loading

DOE used a distribution of values for initial peak loading to characterize the annual peak load served by each transformer in its simulation. The initial peak loading is the ratio of the transformer's peak load in the first year of operation to the transformer's rated load, before accounting for any new load growth that occurs later.[4] DOE selected a distribution of initial peak loadings that had a median of 85 percent, a minimum of 50 percent, and a maximum of 130 percent. Standard engineering practice for sizing distribution transformers selects a transformer based on the expected annual peak of the load being served, with some provision for load growth. Given the provision for future growth, initial peak loading usually is less than 100 percent. In practice, however, there usually is some error in estimating the peak load that will be served, and engineers generally use a discrete set of transformer ratings that are imperfectly matched with the expected peak load. Distribution transformers generally are manufactured in discrete kilovolt-ampere (kVA) ratings and, on average, the next-larger kVA rating is 50 percent larger than the next-lower kVA rating (measured relative to the smaller size). Therefore, the initial peak loading can be as high as 130 percent, because for short periods a transformer can be loaded to more than 130 percent of nameplate capacity.[5] Figure 7.2.2 illustrates the distribution of initial peak loading that DOE used.

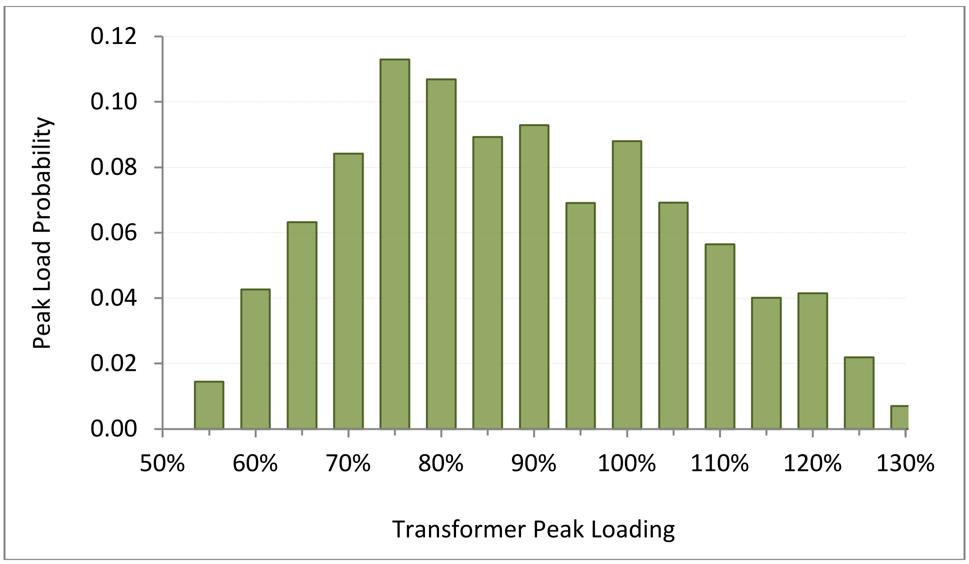

Figure 7.2.2 Distribution of Initial Peak Loading Used in the Hourly Load Analysis

7.2.1.3 Hourly Price-Load Model

The price-load model relates the marginal cost of meeting the next load increment to the current system load. The marginal cost is interpreted as the time-varying marginal price of electricity for a system. The Department estimated the relationship between system loads and system-marginal prices for each region based on hourly data collected by FERC Form 714[3] and, where appropriate, day-ahead market data from independent system operators. FERC data provide hourly system load and lambda values, where the system lambda is defined approximately as the operating cost of the generating unit on the dispatch margin. For regions that have integrated wholesale electricity markets, DOE used the day-ahead market data that include the hourly system load and the market-clearing price. DOE used data for 2008, the most recent year for which data from all sources were available.

The correlation between hourly system prices and loads is illustrated in Figure 7.2.3. This figure shows a scatter plot of price versus load for the SERC region. The data pairs (price and load values in each hour) are sorted into bins based on load level. Those bins are represented by different colors in the figure.

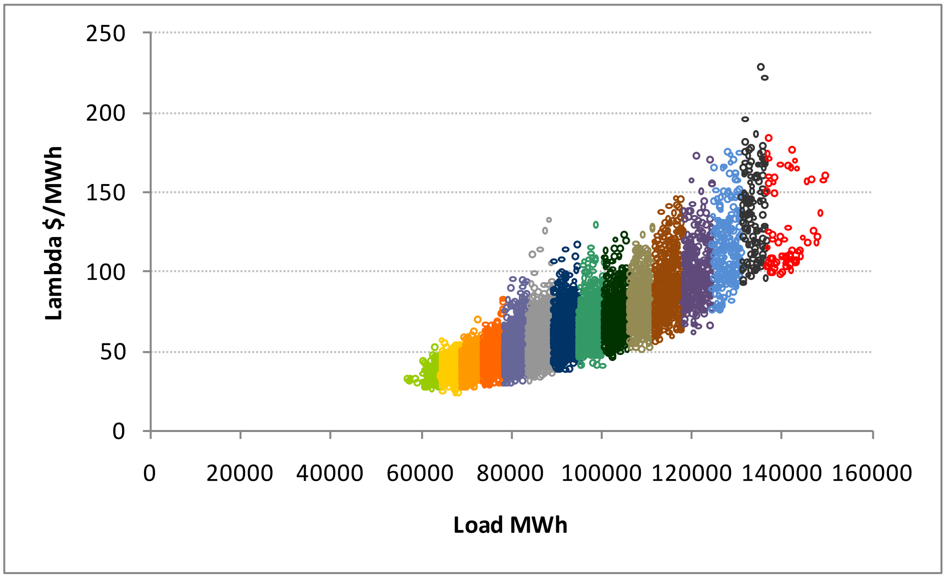

Figure 7.2.3 Binned Load Versus Marginal Price for EMM Region SERC

DOE estimated the marginal system price within each bin as follows.

$$p_j = \bar{p}_j + \delta_j$$

Where:

j	=	the bin index,
$\bar{p}_j$	=	the average value of the prices in bin j and,
δ_j	=	a random increment within bin j.

In general, both the average price and the range of hourly prices increases with system load. To capture the increase in price volatility as a function of system load, DOE added a random increment δ to the average marginal price $\bar{p}$ for each load bin j. To estimate the increment δ_j, DOE used a probability distribution function (PDF) calculated independently for each bin j. The PDF for the increment is assumed to be triangular and centered at zero, with the distribution parameters for each bin determined by the data. The approach is described in more detail in Appendix 7-A.

Within the LCC spreadsheet, system loads are represented using a load distribution function. This function is calculated by counting the number of times the load level falls inside each load bin. The bin sizes are variable and depend on region; the number of bins is constant and equal to fifteen.

7.2.1.4 Transformer Load Simulation

DOE estimated the loads on individual liquid-immersed transformers for both residential and non-residential customers by creating hourly proxy transformer loads. The important quantities for the LCC analysis are the number of hours the transformer is subject to a given load level and the correlation between transformer loads and system loads. The first is important for determining the total load losses, and the second for accurately estimating the economic value of load losses. To estimate the coincident between peak transformer load and system load, DOE constructed a joint probability distribution function (JPDF) based on a dataset consisting of several hundred hourly whole-building loads. For this analysis, a proxy system load was constructed by summing all the available building loads. DOE then estimated the JPDF by defining a set of bins for both the proxy system load and individual load time series, and counting the number of values that fell into each bin. The system load bins used in the JPDF are the same as the load bins used in the hourly price-load model. DOE created a separate JPDF for residential, commercial and industrial customers. Figure 7.2.4 and figure 7.2.5 show separate color plots of the JPDF for commercial, and industrial customers. The figure shows the system load bins on the horizontal axis and the transformer load bins on the vertical axis, with different colors representing the probability that, in a given hour, the system load and transformer loads will fall into the given bin. The figure shows that, for low system loads, transformer loads are distributed broadly, whereas for higher system loads transformer loads are more tightly correlated with system load.

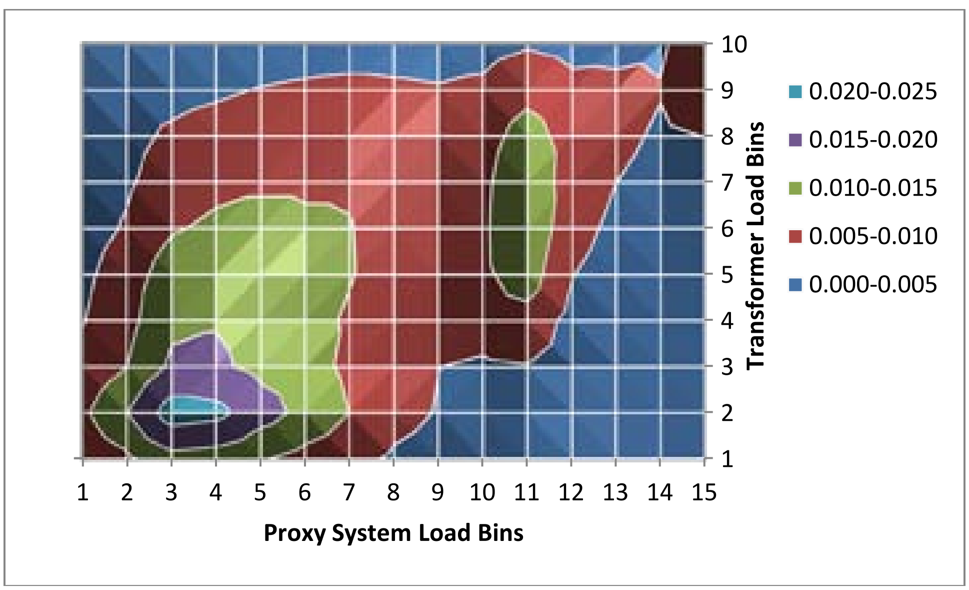

Figure 7.2.4 Average Joint Probability Distribution for Commercial Customers, 1998-2000

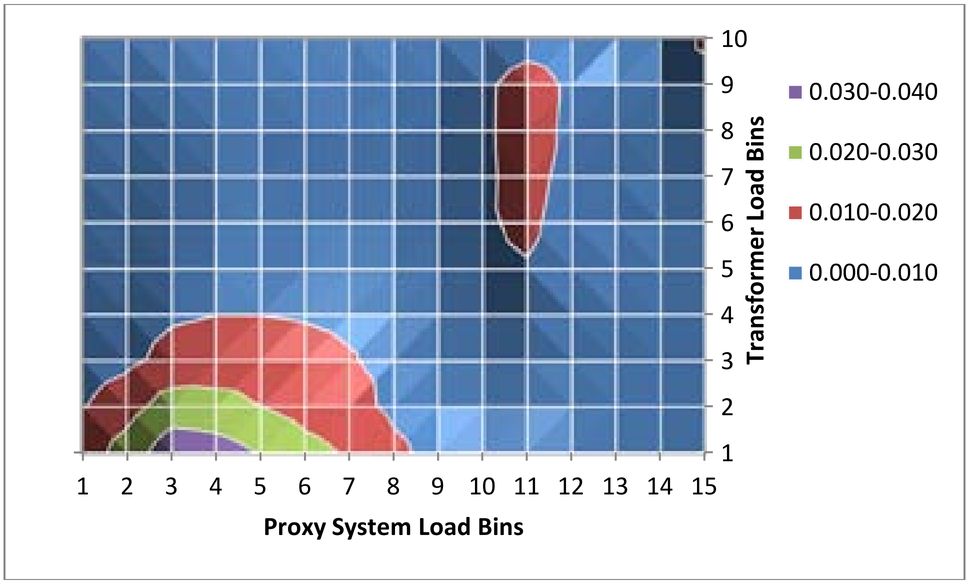

Figure 7.2.5 Average Joint Probability Distribution for Industrial Customers, 1998-2000

7.3 MODEL FOR DRY-TYPE TRANSFORMER LOADS

This section describes the modeling approach DOE used to estimate the loading for dry-type distribution transformers. Given that this type of equipment is owned primarily by C&I entities, which are billed monthly for electricity, DOE developed appropriate methods to estimate the impacts of higher transformer efficiency on monthly energy losses and demand.

7.3.1 Overview of Monthly Load Model

DOE defined a customer sample for dry-type distribution transformers based on building-level data drawn from the EIA's Commercial Buildings Energy Consumption Surveys (CBECS) for 1992, 1995, and 2003. In its analysis, DOE assumed that each building has a transformer, and used building monthly electricity consumption and demand data as inputs to a statistical model that estimates the transformer-level data. DOE determined the economic value of no-load and load losses by the marginal price of electricity for each building, as determined by the electricity tariff. In this analysis, DOE used a previous, detailed study of commercial building energy prices,[6] which showed that every building's electricity costs can be represented as a marginal price for energy and a marginal price for demand. Both prices vary by region and season.

Transformer losses contain a constant component (the no-load or core losses) and a component that depends on the square of the load on the transformer (the load or coil losses). The economic value of transformer losses is a function of the load on the transformer and the timing of that load with respect to variable energy costs and building peak demand. To the extent that there is a correlation between transformer losses and variable energy costs, the cost of the electricity supplying the transformer losses will be different from the average cost of electricity. The LCC analysis for dry-type transformers uses a statistical model of the monthly transformer loss factors, along with a correlation between individual transformer and whole-building loads, to estimate changes in monthly electricity consumption and peak demand and the corresponding electricity cost savings for C&I customers.

7.3.2 Monthly Load Simulation

The monthly load simulation model embedded in the LCC spreadsheet proceeds as follows.

1. A customer (building) is selected from the sample in the spreadsheet; if the building's annual peak load is smaller than the rated capacity of the transformer design under consideration, the building is dropped from the sample.
2. An initial peak loading is assigned to the transformer.
3. The program begins a loop on the monthly electricity consumption and demand data for the building. For each month, the program:
    a. calculates the load factor (LF), which is equal to the ratio of the average load to the peak load for that month;
    b. estimates the transformer loss factor (LSF) as a function of the LF; and
    c. estimates the transformer coincident peak load (CPL) as a function of the LF.
4. The monthly load data are passed to the controlling loop and used in the LCC analysis to calculate the operating cost savings from reduced load losses.

7.3.3 Inputs to Monthly Load Model

The following sections describe the inputs to DOE's monthly load model, which include customer data, initial peak transformer load, transformer loss factor, and coincident peak transformer load.

7.3.3.1 Customer Data

The customer sample for the dry-type transformer LCC analysis was drawn from the 1992 and 1995 CBECS.[7,8] Those survey years were used because they include data on monthly building-level electricity consumption and demand. All 1992 and 1995 samples that provided a complete year of monthly data were combined into a single sample. Weights for the full sample were determined by scaling the original building weights to match the floorspace for the corresponding building categories given in the most recent CBECS (from 2008). The building categories used to define the weights were based on building activity, census division, and building size.

DOE had no comparable sample to provide monthly data for industrial customers. To represent the fraction of transformers that are installed in industrial buildings, DOE assumed that (1) industrial buildings share the load characteristics of the large buildings defined in CBECS, and (2) industrial buildings utilize transformers in a way that is comparable to similarly sized warehouse-type buildings. In the previous final rule for distribution transformers,[9] DOE assumed that monthly demand and usage for large industrial and commercial customers are similar. It verified this assumption by comparing load factor distributions of C&I customers for a utility in the southeastern United States. DOE found that the differences among customer classes were much smaller than those within each class.[9]

DOE used floorspace data from the EIA's 2006 Manufacturing Energy Consumption Survey[10] to estimate the total floorspace of industrial buildings that would contain transformers covered by this rulemaking. This floorspace was added to the CBECS-based floorspace for large commercial buildings to determine total weights for each building in the customer sample.

Buildings having annual peak loads less than the transformer capacity specified in the design under consideration were screened out of the sample. The customer sample contains a range of building sizes having a wide range of annual peak loads. Although larger buildings undoubtedly contain multiple transformers, DOE currently has no quantitative information on how the number of transformers in a building scales with either the building floorspace or the building annual peak load. Thus, to account for the effect of multiple transformers in a single building, DOE used a simple approach whereby it multiplied the building sample weight by the number of floors in the building.

7.3.3.2 Initial Peak Transformer Load

Initial peak load is the annual peak load on the transformer in the first year of operation divided by its rated capacity. The Institute of Electrical and Electronics Engineers (IEEE) has a *Draft Guide for Distribution Transformer Loss Evaluation*[11] that defines a similar measure of peak transformer loading called an "equivalent annual peak load," which accounts for changes in peak load throughout the life of a transformer. IEEE's *Draft Guide*, which refers to the initial peak loading as "initial transformer loading," uses values of 0.9 and 0.95 in its example calculations. Rather than applying the IEEE's equivalent annual peak load, DOE accounted for annual changes in peak load in the LCC calculation by applying an annual rate of change in transformer load. DOE characterized a range of initial peak loads by defining a distribution of initial peak loads.

Distribution transformers generally are manufactured in discrete kVA ratings that represent their power-handling capacity. On average, each higher kVA rating is 50 percent larger than the previous kVA rating (measured relative to the smaller rating). Transformers can be loaded above their kVA rating (or nameplate capacity) for short periods. However, transformers are often sized conservatively to avoid the possibility of an overload, especially for low-voltage, dry-type transformers. DOE received stakeholder comments that medium-voltage, dry-type transformers are loaded more heavily than are low-voltage, dry-type transformers.[12] DOE therefore selected higher initial peak loading for medium-voltage, dry-type transformers than for low-voltage dry-types. If electrical engineers accurately size dry-type transformers conservatively with a 10-percent safety margin relative to the nameplate capacity, initial peak load ranges from 60 percent to 90 percent. The high end of the range is the maximum initial peak load that allows for a 10-percent margin of safety. The low end of the range reflects the threshold peak load at which the next-smaller kVA rating will provide 90 percent peak loading. In response to stakeholder comments, DOE adjusted this assumption for medium-voltage, dry-type transformers, selecting initial peak loadings that were 10 percent higher than for the low-voltage, dry-type transformers. Thus the distribution of initial peak load for low-voltage, dry-type transformers has a constant probability between 60 percent and 90 percent of nameplate capacity; the distribution for medium-voltage, dry-type transformers has a constant probability between 70 percent and 100 percent of nameplate capacity.

DOE believes that, in selecting an appropriate kVA rating for an application, engineers choosing dry-type transformers are conservative and do not take advantage of the fact that transformers can be safely overloaded for short periods. The National Electric Code[13] encourages conservative transformer sizing by requiring a transformer that is serving a secondary circuit of less than 600 volts to be rated at not less than 80 percent of the total amperage of the secondary circuit protection (table 450.3(A) of the code).

7.3.3.3 Transformer Loss Factor

For a distribution transformer, the loss factor (LSF) is the ratio of the annual average load losses to the peak value of load losses. The LSF is equal to the average of the square of the transformer load divided by the square of the peak transformer load.

The characteristics of transformer load DOE needed for C&I building owners are the energy and demand savings associated with load losses. The energy savings depend on the LSF, which is proportional to the average value of the squared load. To estimate the load loss factor for each building, DOE used an expression that relates LSF to load factor (LF):

$$LSF = \alpha * LF + (1-\alpha) * LF^2$$

where α is a parameter with $\alpha < 0.5$. The LF, which is available from the CBECS data, is equal to the ratio of the average hourly load to the peak load. DOE estimated a probability distribution for the parameter α based on hourly building load data from the End-Use Load and Consumer Assessment Program (ELCAP)[6] survey and additional confidential data from stakeholders.

7.3.3.4 Coincident Peak Load

Coincident peak load (CPL) captures the coincidence between a transformer's load and the building's peak load. For a building that has a single transformer, the coincidence would be perfect, and the CPL would equal one. In practice, the degree of coincidence depends on how transformers are installed in the building. To model the diversity within transformer loads and total building loads, DOE constructed a statistical model that predicts the CPL as a function of a building's load factor. The statistical model is based on data for monthly LFs and LSFs calculated using hourly building load data from the ELCAP dataset[6] and other data. The modeling approach is discussed in more detail in Appendix 7-A.

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CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

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CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

8.1 INTRODUCTION

This chapter of the technical support document (TSD) prepared in support of potential energy efficiency standards for distribution transformers presents DOE's life-cycle cost (LCC) and payback period (PBP) analyses. It describes the method DOE used for analyzing the economic impacts of possible standards on customers. The effect of standards on customers includes a change in operating expense (usually a decrease) and a change in purchase price (usually an increase). The LCC and PBP analyses produce two basic outputs to describe the effect of standards on customers.

- LCC is the total (discounted) cost that a customer pays over the lifetime of the equipment, including purchase price, installation cost, and operating expenses.

- PBP measures the amount of time it takes customers to recover the estimated higher purchase price of more energy efficient equipment through lower operating costs.

This chapter presents inputs and results for the LCC and PBP analyses, as well as key variables, assumptions, and computational equations. DOE performed the calculations discussed here using a series of Microsoft Excel spreadsheets, which are accessible on DOE's website (http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html). Appendix 8A contains details and instructions for using the spreadsheets. There are five appendices to this chapter, among which are appendix 8C, which presents a complete set of analytical results; appendix 8B, which discusses uncertainty and variability; and appendix 8D, which contains a complete set of sensitivity results for transformer design lines 1, 7, and 12.

8.1.1 General Approach to Analyses

Recognizing that each transformer customer is unique, DOE calculated the LCC and PBP for a representative sample (a distribution) of individual customers who purchase individual transformers. In this manner, DOE's analyses explicitly recognized that there is both variability and uncertainty in the inputs. DOE developed the LCC model using Excel spreadsheets combined with Crystal Ball, a commercially available add-in program. DOE used Monte Carlo simulations to model the distributions of inputs. The Monte Carlo process statistically captures input variability and distribution without testing all possible input combinations. The results are expressed as the number of transformers that engender economic impacts of varying magnitudes. Appendix 8-B provides a detailed explanation of the Monte Carlo simulation process and the use of probability distributions in the analyses.

The LCC results are displayed as distributions of impacts compared to baseline conditions (no new standards). The tabular results presented later in this chapter are based on 10,000 samples per Monte Carlo simulation run.

DOE developed two approaches for the LCC calculations: one for liquid-immersed transformers, and one for low-voltage and medium-voltage, dry-type transformers. Because most owners of liquid-immersed transformers are utilities, the LCC calculations for liquid-immersed transformers used utility marginal costs and distribution markups that do not include wholesaler or contractor markups. In contrast, because most owners of dry-type transformers are commercial and industrial enterprises, DOE used monthly marginal electricity costs and complete distribution markups for calculating the LCC of dry-type transformers. For simplicity, DOE used only one type of LCC calculation for each design line of transformer, based on the type of owner that was the majority in that category.

8.1.2 Base Case Scenario

In developing appliance standards, DOE used the existing standard (*10 CFR Part 43*) as a baseline from which it calculates the impact of any efficiency level. This approach focused on the mix of selection criteria customers are known to use when purchasing transformers. Those criteria include first cost and what is known in the transformer industry as total owning cost (TOC), a criterion some customers use in place of first cost. Purchasers of distribution transformers, especially in the utility sector, have long used TOC to determine which transformers to purchase.[1,2]

To establish the baseline scenario for the LCC, DOE used distributions of efficiencies and an estimated percent of transformers currently being purchased using the TOC method. That scenario represents the range of transformer costs and efficiencies that transformer purchasers likely would face without national energy efficiency standards in place.

8.1.2.1 Design Limitation in the Base Case

During the negotiation process, DOE heard from ERAC subcommittee members noted that currently ZDMH core steel is not used in significant quantities in the U.S. market. Therefore, DOE screened out designs using this material in the base case selection. For higher efficiency levels, the LCC analysis samples from all design options identified in the engineering analysis.

Subcommittee members provided DOE data on market share as a function of efficiency. For some design lines, the lower boundary of the price-efficiency curve produced in the engineering analysis (see chapter 5) is quite flat, so that the choice algorithm (see section 8.2.2.2) in the LCC analysis showed units being selected in the base case with efficiencies substantially higher than the current DOE minimum standard. DOE modified its approach so that the fraction of units selected in the base case at different efficiency levels is consistent with the provided market share data.

8.1.3 Total Owning Cost

The utility industry developed TOC evaluation as an easy-to-use tool to reflect the unique financial environment faced by each transformer purchaser. To express variation in such factors as the costs of electric energy, energy capacity, and financing, the utility industry developed a range of factors, called A and B values, to use in their evaluations. A and B are the equivalent first costs of a transformer's no-load losses and load losses, respectively, in dollars per watt ($/W). No-load losses refer to the core losses that remain roughly constant after the transformer is energized; load losses are the coil losses that vary roughly with the square of the load on the transformer.

After assigning an economic value to the A and B parameters of transformer losses, purchasers add those costs to the first cost of acquiring the transformer, thereby deriving TOC. Throughout the LCC analysis, DOE expresses monetary values in units of year 2010 real dollars (2010$). The equation for calculating transformer TOC is:

$$TOC = FC + (A \times NLL) + (B \times LL).$$

Where:

FC	=	first cost of acquiring the transformer, including purchase price and installation cost (2010$);
A	=	the no-load loss valuation parameter in dollars per watt ($/W);
NLL	=	the no-load loss at nameplate load (W);
B	=	the load loss valuation parameter ($/W); and
LL	=	the load loss at nameplate load (W).

8.2 LIFE-CYCLE COST ANALYSIS METHOD

The following sections present the LCC equation and define its terms, then describe the nine key steps DOE used in performing the LCC for distribution transformers.

8.2.1 Definition

The LCC equation serves as the basis for both the LCC analysis and the LCC spreadsheet model. The LCC equation reflects both the first cost of a transformer and the present value of the operating costs throughout the service life of that transformer. The LCC equation is:

$$LCC = FC + \sum_{1}^{Lifetime} \left(\frac{OC_n}{(1+Drate)^n} \right).$$

Where:

FC	=	the first cost (2010$);
n	=	the index for the year of operation (yr);
Lifetime	=	the service life of the transformer;
OC_n	=	the operating cost in year *n*, including the value of the losses and maintenance costs (2010$/yr); and
Drate	=	the discount rate applied to the calculation (%).

8.2.2 Key Steps in Life-Cycle Cost Analysis

Although the LCC relies on a simple equation, DOE's LCC spreadsheet model accounts for the dynamic nature of numerous inputs throughout the service life of a transformer. A simplified flowchart (Figure 8.2.1) illustrates the key steps implemented in the LCC spreadsheet: the primary inputs, the key computational steps, and the important outputs. The LCC spreadsheet are available as an Excel files on the DOE website at http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html.

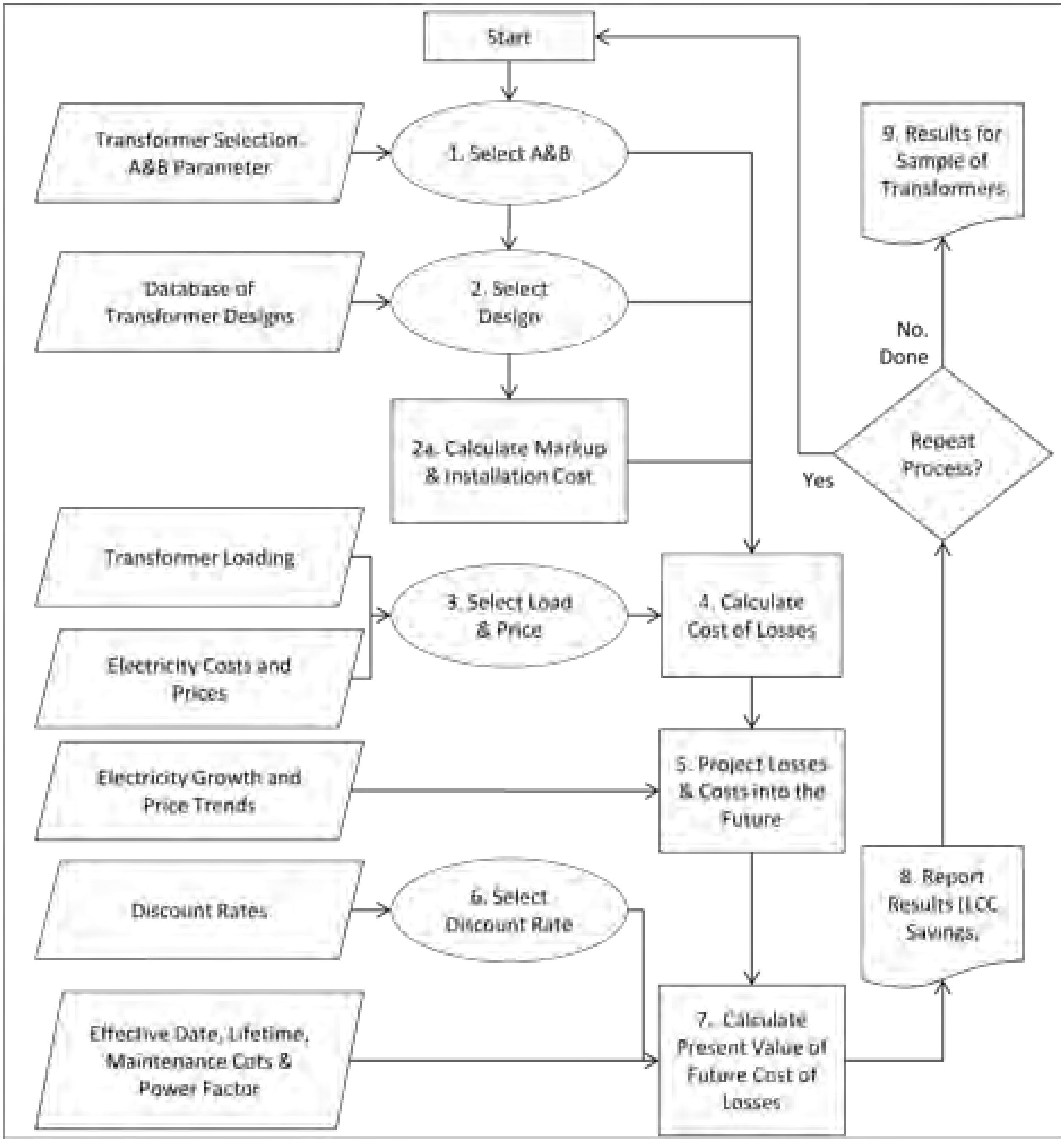

Figure 8.2.1 Flowchart of Spreadsheet Model for Calculating Transformer Life-Cycle Cost

Sections 8.2.2.1 through 8.2.2.11 describe the analytical steps of the LCC model shown in the flowchart. Following this description, this chapter presents the specific inputs that DOE developed and then used in the LCC model for this rulemaking (section 8.3). Next, the chapter presents the results of the LCC model runs for the various design lines (section 8.4), and the key sensitivities to those results (section 8.5).

The calculation of LCC determines the financial impact of the imposition of energy efficiency standards for distribution transformers from the perspective of the customer, or the owner of the transformer. Several types of information are necessary for the calculation: the first cost of transformers with and without standards, operating costs of transformers with and without standards, the year the standard would become effective, and the lifetime of transformers. Section 8.3 explains in more detail DOE's inputs to the LCC.

8.2.2.1 Step 1: Select Parameters A and B

The spreadsheet user selects customer choice of A and B parameters from the choices on the *A & B Dist* worksheet. This step establishes the current environment for the purchasing decision. For liquid-immersed transformers, DOE assumed that 90 percent are purchased based on lowest first cost and 10 percent are purchased using the TOC evaluation.

When deciding on which dry-type transformers to purchase, commercial and industrial (C&I) entities also may use an evaluation based on parameters A and B. Although C&I purchasers use a different analytic process for determining A and B values from that used by electric utilities, the fundamental meanings of A and B are the same for both groups of purchasers.

The LCC spreadsheet uses two different models of A and B to simulate the two different transformer purchase decisions. One model is used for all liquid-immersed transformer design lines, and a different model for dry-type design lines. The specific inputs to the two scenarios are given in section 8.3 of this TSD chapter, as well as in the *A & B Dist* worksheet of the LCC spreadsheets for liquid-immersed and the *Demand and Usage* worksheet for dry-type units. These scenarios can be selected using the "Transformer Customer A's and B's" pull-down menu on the *Summary* worksheet. Step 2 below explains the application of the A and B distributions when selecting transformer designs.

8.2.2.2 Step 2: Select Designs that Meet a Chosen Efficiency Level

Step 2a: The spreadsheet model selects a efficiency level (EL) and its associated transformer designs to evaluate. DOE developed as many as seven ELs for each design line based on information obtained from the engineering analysis (see chapter 5). The engineering analysis yielded a cost-efficiency relationship in the form of manufacturer selling prices, no-load losses, and load losses for a range of realistic transformer designs. This set of data provided the LCC model with a distribution of transformer design choices. (The *Design Table* worksheet provides a condensed version of the engineering analysis output.) After the user chooses a EL, the spreadsheet selects from its database of designs the subset of designs that satisfy the selected EL and another set of designs that satisfy the baseline scenario.

In addition to the economic value of load and no-load losses, other factors may affect design selection. DOE accounted for such factors by adding a random factor to the transformer's first cost. By incorporating this factor, DOE captured the range of typical real-world variation in the first cost of a transformer. DOE modeled this random cost factor as a uniformly distributed random number that can either increase or decrease the first cost of the transformer by as much as 5 percent. The spreadsheet selects the transformer design that has the lowest TOC (including the random cost factor) for the customer. For each iteration cycle, a design is chosen based on distributions of A and B parameters from Step 1.

Step 2b: The spreadsheet model calculates markup and installation costs. For liquid-immersed transformers, which typically are purchased directly by utilities from manufacturer representatives, DOE considered the transformer purchase price to be the manufacturer selling price plus a distributor markup and sales tax. It added installation costs separately. For dry-type transformers, the distribution channel includes various intermediaries who add their own costs to the manufacturer selling price. Those costs include a manufacturer markup, distributor markup, contractor markup, installation costs, and sales tax. For this step key inputs include markup and installation costs. DOE presents its specific values for those inputs in chapter 6 of this TSD.

8.2.2.3 Step 3: Select Load and Price Profile

The spreadsheet model dynamically selects a sample transformer load profile from distributions derived from available data. For liquid-immersed transformers, DOE developed an hourly transformer load simulation model to capture the dynamics and economics of transformer loads. DOE then used the marginal cost for the cost of electricity.

To estimate the impact of transformer losses on C&I companies' electricity bills, DOE modeled the relationship between monthly transformer load characteristics and customer demand and usage. It developed a method to calculate customer monthly bills and derived distributions of load parameters from available hourly load data.

The load profiles and characteristics are provided in the *Price Load Model* worksheet of the LCC spreadsheet for liquid-immersed transformers and in the *Demand & Usage* worksheet of the LCC spreadsheet for dry-type transformers. For both types of transformers, DOE calculated the total cost of electricity both with and without transformer losses and used the difference to calculate incremental electricity costs. Section 8.3.5 provides a detailed discussion of the electricity price analysis.

8.2.2.4 Step 4: Calculate Cost of Losses

The spreadsheet model estimates the incremental impacts of no-load and load losses from the loss coefficients of the design, the monthly customer load characteristics (demand and usage), and the cost of electricity. In this step, the spreadsheet combines the no-load losses, load losses, and electricity price information for each transformer in the baseline scenario and in the chosen standards scenario. Subsequent steps project the costs of losses into the future and then convert them back to present values.

8.2.2.5 Step 5: Project Losses and Costs into the Future

The spreadsheet model projects losses and costs into the future based on assumptions regarding load growth and a forecast of future changes in electricity price. Spreadsheet users can select various scenarios for load growth and future electricity price. The model applies the selected options to the initial cost of losses that were calculated in Step 4. DOE presents its specific load growth and electricity price trends in the LCC inputs section (section 8.3) of this chapter.

8.2.2.6 Step 6: Select Discount Rate

To discount the future stream of costs into a present value, the spreadsheet model selects a discount rate from a distribution. The LCC spreadsheet selects a discount rate from a weighted sample of discount rate inputs derived from the financing costs of purchasing transformers. DOE presents its specific discount rates in the LCC inputs section (section 8.3) of this chapter.

8.2.2.7 Step 7: Calculate Present Value of Future Cost of Losses

The spreadsheet model calculates the present value of future operating costs and losses and the present worth per watt of no-load and load losses. This step applies the discount rate selected in Step 6 to the future costs of losses from Step 5 to produce a single, present-valued number. In addition to the costs from Step 5, the calculation uses as inputs the effective date of the standard, the transformer lifetime, maintenance costs, and a power factor.

8.2.2.8 Step 8: Report Results

The spreadsheet model provides the LCC, LCC savings, payback period, and other results for inclusion in the distribution of results.

8.2.2.9 Step 9: Repeat Process and Report Results

When applying the Monte Carlo simulation, the model performs a user-defined number of iterations and reports the results as distributions. The specific number of iterations for the Monte Carlo simulation is specified through the “Repeat Process” decision box. Based on DOE’s rulemaking experience with expressing results as distributions, 10,000 iterations in a Monte Carlo simulation capture sufficient variability. When the specified number of iterations has been reached, the model ends the simulation process and generates result reports.

8.3 INPUTS TO LIFE-CYCLE COST ANALYSIS

This section describes the LCC inputs used in the spreadsheet model and provides definitions and data sources for each input. This section also elaborates on how the LCC spreadsheets apply certain user-chosen inputs to the model. The specific inputs to the model, in the order in which they appear on the left-hand side of the LCC flowchart (Figure 8.2.1), are:

- transformer selection A and B parameters
- database of transformer designs
- markup and installation costs
- transformer loading

- electricity costs and prices
- load growth trends
- electricity growth and price trends
- discount rates
- effective date of standard
- transformer service life
- maintenance costs
- power factor

8.3.1 A and B Transformer Selection Parameters

The A and B transformer selection parameters that DOE used in calculating total owning cost (TOC) characterize the value that transformer purchasers place on reducing no-load and load losses, expressed in terms of dollars per watt of reduced losses. Using A and B parameters to represent a customer's choice of transformer implies that the value of loss reduction is proportional to the amount by which losses are reduced. Given the wider applicability of the TOC formulation to the expression of loss valuations, DOE used A and B parameters to formulate a customer choice model.

To represent the potential range of purchasers' valuation of losses, DOE developed three customer choice scenarios for each LCC calculation. The difference among the three scenarios is the fraction of purchasers who place a value on reducing transformer losses. Those who place a value on reducing losses are described as *evaluators;* those who do not consider transformer losses during a purchase decision are termed *non-evaluators*. The scenario representing non-evaluation for all purchases has 0 percent evaluators, while the scenario representing evaluation for all purchases has 100 percent evaluators.

For liquid-immersed transformers, DOE's default scenario is an evaluation rate of 10 percent. Because few purchasers consider transformer losses as part of the purchase decision for low and medium-voltage, dry-type transformers, DOE assumed a default evaluation rate of 2 percent.

DOE used the 0-percent and 100-percent evaluation scenarios to test the LCC sensitivity to changes in the percentage of transformers purchased using TOC. It estimated the mean value of A for evaluators from public transformer purchase bids available on the Internet.[3,4,5,6,7,8,9,10,11] Then, recognizing that there is substantial variability in the value that transformer purchasers may place on reducing losses, DOE created separate statistical models for A and B for liquid-immersed and dry-type transformers.

For each value of A that a transformer purchaser may use, there is a range of possible B values that are consistent with the particular A parameter. (B parameters relates to the value associated with load losses.) In general, the ratio of B to A is a measure of the relative importance of load losses and no-load losses. For a transformer that is constantly loaded at 100 percent of rated capacity, the values of B and A should be the same, because both load and no-load losses will always be at their rated values. Load losses increase with the square of the load, and transformer mean loads are almost always less than 100 percent. Therefore, in practice, B is always less than A, and is approximately equal to A times the square of the expected load (not considering peak loads).

8.3.1.1 A and B Parameter Selection for Liquid-Immersed Transformers

DOE collected A and B parameter values from transformer purchase bids available on the Internet and combined these with the sample used in the previous final rule.[3] The bid documents were published in various years. In order to evaluate the data, DOE therefore normalized the A and B values to 2010$ using the U.S. Bureau of Labor Statistics' Producer Price Index for power generation, transmission, and control.[12]

A Parameter: To model the distribution of A values in the data, DOE developed a piecewise linear fit to the empirical distribution. Figure 8.3.1 shows the cumulative distribution function for both the data and the model.

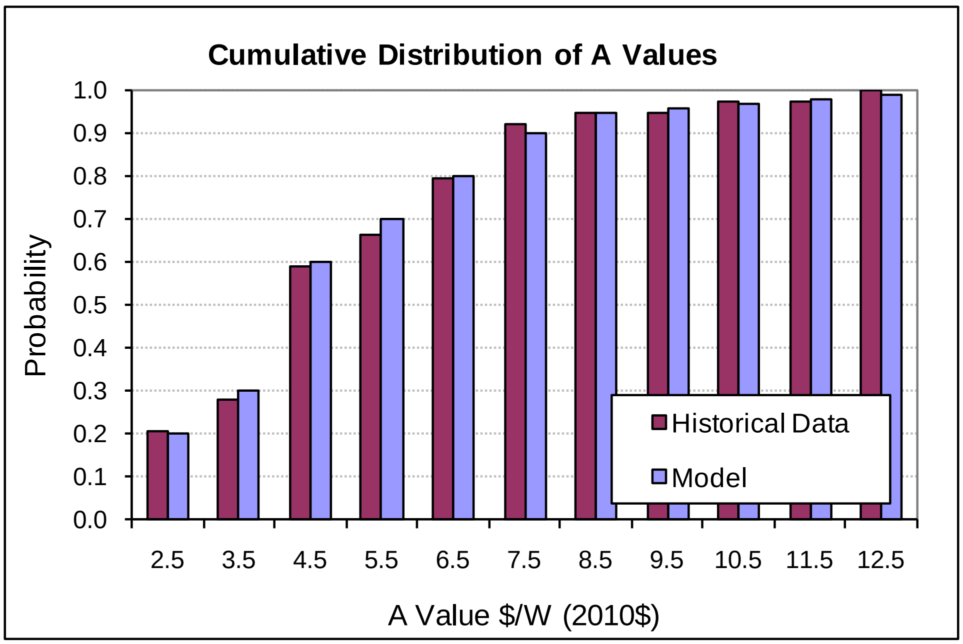

Figure 8.3.1 Cumulative Distribution of Historical A Parameter and Model A Parameter

Table 8.3.1 lists midpoints for the A parameter and the cumulative probability of each midpoint estimated by the model, along with the probability derived from the historical data.

Table 8.3.1 A Parameter Model and Historical Data

A Parameter Midpoint *$/W*	Cumulative Probability, Model *%*	Cumulative Probability, Historical Data *%*
2.5	0.20	0.2051
3.5	0.30	0.2821
4.5	0.60	0.5897
5.5	0.70	0.6667
6.5	0.80	0.7949
7.5	0.90	0.9231
8.5	0.95	0.9487
9.5	0.96	0.9487
10.5	0.97	0.9744
11.5	0.98	0.9744
12.5	0.99	1.0000

B Parameter: The data show that the value of the B parameter depends somewhat on the value of A used by the purchaser, with most of the data points lying in two distinct clusters. The clusters, which represent different ratios of B to A, likely reflect the different technologies used to serve base load and peak load. The first cluster, consisting of approximately 40 percent of the sample, has a B:A ratio of 0.24 and represents utilities that place relatively low economic value on load losses. The second cluster has a B:A ration of 0.46 and represents utilities that place relatively higher economic value on load losses. Figure 8.3.2 illustrates the two clusters. Each cluster is modeled as a linear fit plus a random increment. In the LCC model, purchasers are assigned randomly to one or the other category of B to A ratio, in the same proportion as seen in the data.

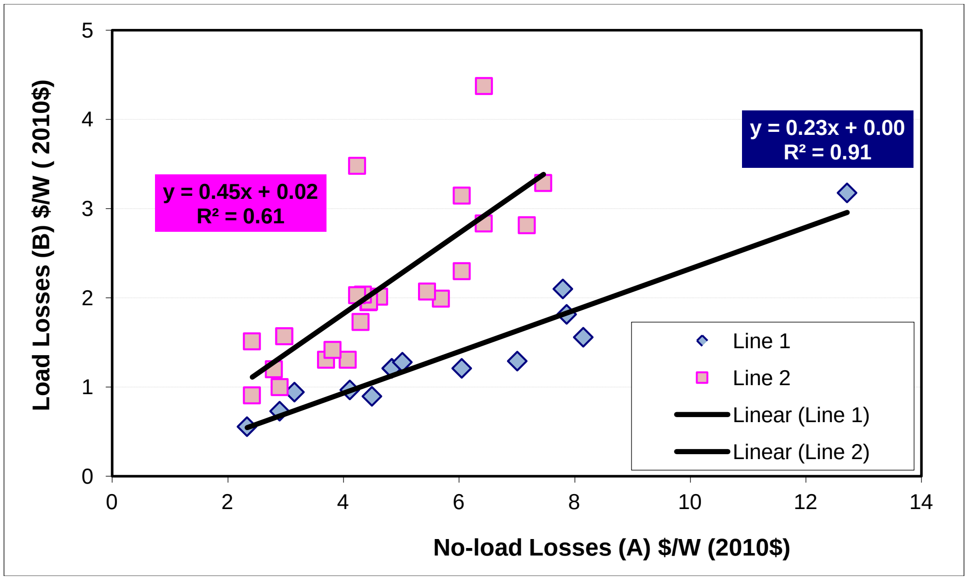

Figure 8.3.2 Distributions of Load Loss (B) Values versus No-Load Loss (A) Values for Liquid-Immersed Transformers

8.3.1.2 A and B Parameter Selection for Dry-Type Transformers

DOE developed models of A and B parameters for dry-type transformers that differ from those used for liquid-immersed transformers. The C&I building owners of dry-type transformers pay for the energy dissipated by the transformer at a price specified by their electricity tariff. DOE estimated that 60 percent of dry-type transformers are installed in commercial buildings, and 40 percent in industrial buildings.[13] The LCC accounts for this distribution by adjusting the weights of individual buildings. For each design line, only buildings having a peak load larger than the transformer capacity are included in the customer sample.

A Parameter: DOE used the following equation to convert the customer's marginal electricity prices to the appropriate A parameter.

$$A = \frac{HP_W \times MPE_W + HP_S \times MPE_S + M_W \times MPD_W + M_S \times MPD_S}{FCR}.$$

Where:

MPE_W = the winter marginal energy charge ($/kilowatt-hour [kWh]) (see section 8.3.5.2;
MPD_W = the winter marginal demand charge ($/kW) (see section 8.3.5.2);
MPE_S = the summer marginal energy charge ($/kWh) (see section 8.3.5.2);
MPD_S = the summer marginal demand charge ($/kW) (see section 8.3.5.2)
HP_W = the number of hours in the winter period;
HP_S = the number of hours in the summer period;

M_W = the number of months in the winter period, defined as October through April;
M_S = the number of months in the summer period, defined as May through September; and
FCR = the fixed charge rate, here equal to 0.2.[14]

B Parameter: The equation for B is similar to that for A, modified to account for the fact that load losses depend on the square of the load on the transformer. The transformer load loss rate is defined assuming the transformer is fully loaded; in reality most of the time a transformer is only partly loaded. This situation is accounted for by the transformer loss factor (LSF), which is equal to the average of the square of the transformer load divided by the square of the peak transformer load. The building peak load is reduced by an amount equal to the square of the load on the transformer at the time of the building peak; this effect is accounted for by the transformer peak responsibility factor. The formula for the B parameter is:

$$B = {LSF(HP_W \times MPE_W + HP_S \times MPE_S) + RF(M_W \times MPD_W + M_S \times MPD_S)} / {FCR}$$

Where:

LSF = the transformer energy loss factor, which is equal to the square of the transformer root mean square (RMS) load; and
RF = the transformer peak responsibility factor, which is equal to the square of the ratio of the transformer load during the hour of the building peak to the peak transformer load.

For both A and B parameters, the fixed charge rate is used to convert the annual cost of load losses to a net present value.

To summarize, DOE characterized transformer purchases with respect to efficiency in terms of two economic valuation parameters. The parameter A expresses the value that a customer gives to reducing no-load losses in dollars per watt, while the parameter B expresses the value given to reducing load losses at rated load. DOE described purchase behavior in terms of evaluators who place a value on reducing losses, and non-evaluators who place no value on reducing losses. DOE investigated four scenarios as sensitivities: (1) liquid-immersed, (2) small-capacity low-voltage dry-type, (3) small-capacity medium-voltage dry-type and (4) large-capacity medium-voltage dry-type. The A and B parameter evaluation rates for the low, medium and high sensitivities for each of those scenarios are shown in Table 8.3.2. For evaluators, DOE used a distribution of A and B values to characterize the economic criteria used in the purchase decision.

Table 8.3.2 A and B Parameter Evaluation Scenarios

	Percentage of Evaluators %		
	Low	**Medium**	**High**
Liquid-immersed	0	10	100
Low-voltage dry-type	0	2	100
Medium-voltage dry-type	0	2	100

8.3.2 Database of Transformer Designs

Establishing a relationship between cost and efficiency is an integral part of DOE's rulemaking process. For transformers, DOE derived this relationship from a database developed during the engineering analysis (chapter 5) of selling prices, no-load losses, and load losses for the range of realistic transformer designs contained in the LCC spreadsheets. DOE used a commercial transformer design software company, Optimized Program Service Inc., and its software to create the database of designs. The database comprises a wide range of efficiencies and manufacturer selling prices (including a predetermined manufacturer markup) to represent the variability of designs in the marketplace. Chapter 5 provides more detail on the method DOE used to generate the database of transformer designs and the database structure.

8.3.3 Markup and Installation Costs

Bringing a manufactured transformer into service as an installed piece of electrical equipment entails costs for markups, sales tax, and installation.

For liquid-immersed transformers, which utilities typically purchase directly from manufacturers, DOE considered the transformer purchase price to be the manufacturer selling price plus, in some cases a distributor markup, and sales tax. DOE added installation costs separately. For dry-type transformers, the distribution channel includes intermediaries who add their own costs to the manufacturer selling price. Costs therefore include a manufacturer markup, distribution markup, contractor markup, installation cost, and sales tax. See chapter 6 of this TSD for a detailed discussion of the markup calculations.

8.3.3.1 Projection of Future Product Prices

To derive a price trend for medium-sized electric motors, DOE obtained historical Producer Price Index (PPI) data for electric power and specialty transformer manufacturing spanning the time period 1969-2010 from the Bureau of Labor Statistics' (BLS).[a] The PPI data reflect nominal prices, adjusted for product quality changes. An inflation-adjusted (deflated) price index for integral horsepower motors and generators manufacturing was calculated by dividing the PPI series by the Gross Domestic Product Chained Price Index (see Figure 8.3.3**Error! Reference source not found.**).

[a] Series ID PCU335311335311; http://www.bls.gov/ppi/

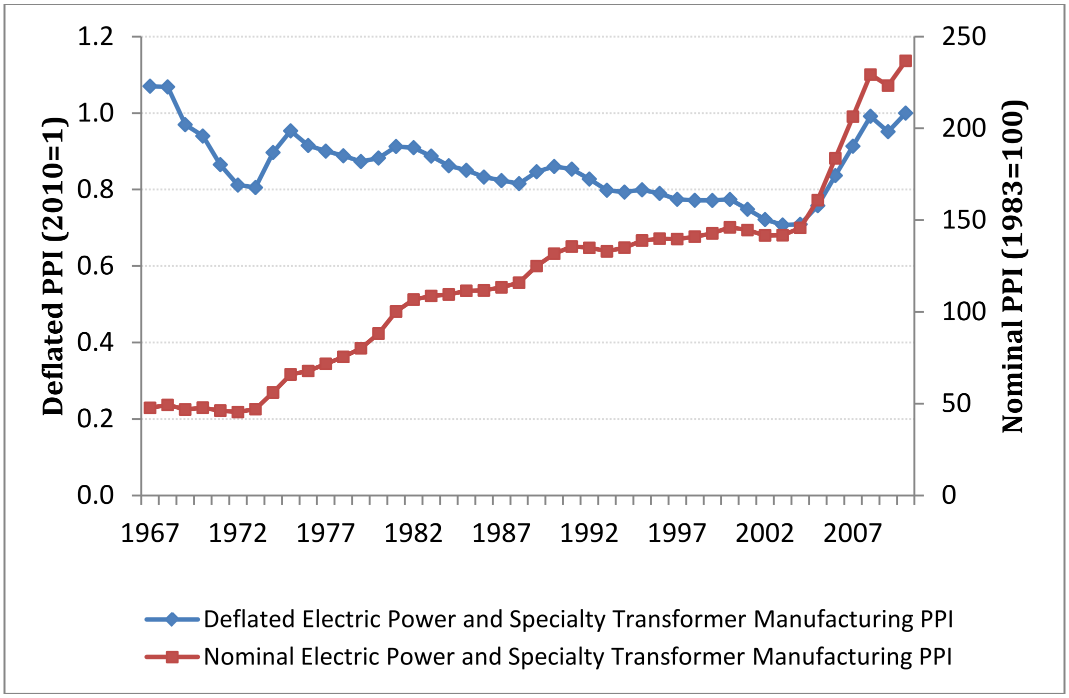

Figure 8.3.3 Historical Nominal and Deflated Producer Price Indexes for Electric Power and Specialty Transformer Manufacturing

From the mid-1970s to 2005, the deflated price index for transformers was in decline. Since then, the index has risen sharply, primarily due to rising prices of copper and steel products that go into manufacturing transformers (see Figure 8.3.4). The rising prices for copper and steel products were primarily a result of strong demand from China and other emerging economies. Given the slowdown in global economic activity in 2011, DOE believes that the extent to which the trends of the past five years will continue is very uncertain. DOE performed an exponential fit on the deflated price index for transformers, but the R^2 was relatively low (0.21).

Given the above considerations, DOE decided to use a constant price assumption as the default price factor index to project future distribution transformers prices in 2016. Thus, prices forecast for the LCC and PBP analysis are equal to the 2010 values for each efficiency level in each product class.

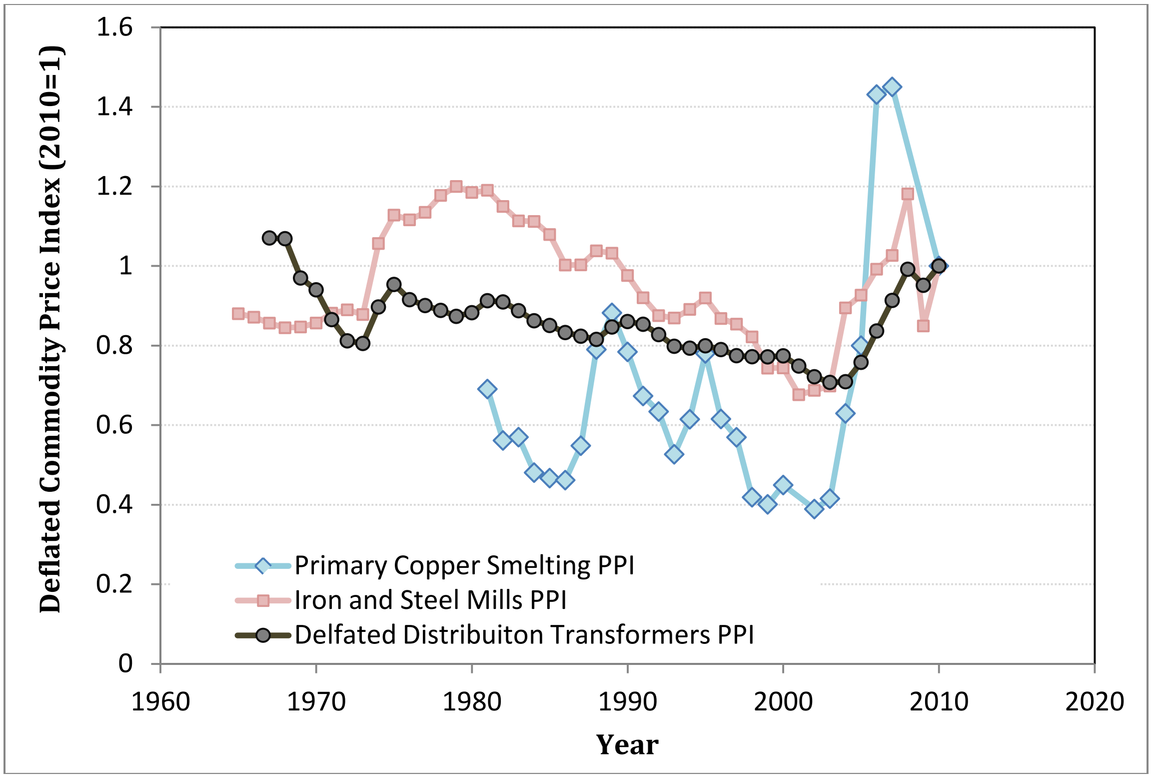

Figure 8.3.4 Historical Deflated Producer Price Indexes for Copper Smelting, Steel Mills Manufacturing and Electric Power and Specialty Transformer Manufacturing

8.3.4 Transformer Loading

To estimate the economic burdens and benefits of efficiency improvements, DOE characterized the energy use and losses of distribution transformers by estimating the loads on them. Because the applications for distribution transformers vary significantly by type of transformer (liquid-immersed or dry-type) and ownership (95 percent of electric utilities own liquid-immersed; C&I entities primarily use dry-type), DOE performed two separate load analyses to evaluate the efficiency of the two types of distribution transformers. Chapter 7 of this TSD, Energy Use and End-Use Load Characterization, describes the two separate load analyses.

8.3.4.1 Loading Levels for Utilities Serving Low Population Densities

DOE recognizes that rural areas the number of customers per transformer is likely to be significantly lower than in urban or suburban areas, which in turn results in lower root-mean-square (RMS) loads. To account for this effect, DOE performed an analysis to determine an average population density in the territory served by each of the utilities represented in the LCC simulation. This analysis is implemented for liquid-immersed design-lines 1through 5. For each utility, EIA Form 861 data were used to generate a list of counties served by the utility. Census data were used to determine the average housing unit density in each county. An average over counties was then used to assign the utility to a low density, average density or high density category, with the cutoff for low density set at 32 households per square mile. For those utilities serving primarily low density residential areas the median of the RMS load distribution is reduced from 35 percent to 25 percent.

8.3.5 Electricity Price Analysis

This section describes the electricity price analysis DOE performed to determine the energy portion of the annual operating expenses for distribution transformers. DOE performed two types of analyses: one investigated the nature of hourly transformer loads, their correlation with the overall utility system load, and their correlation with hourly electricity costs and prices; another estimated the impacts of transformer loads and resultant losses on monthly electricity usage, demand, and electricity bills. DOE refers to the two analyses as *hourly* and *monthly* analyses, respectively. DOE used the hourly analysis for liquid-immersed transformers, which are owned predominantly by utilities that pay costs that vary by the hour. DOE used the monthly analysis for dry-type transformers, which typically are owned by C&I establishments that receive monthly electricity bills.

8.3.5.1 Hourly Marginal Electricity Price Model for Liquid-Immersed Transformers

To evaluate the electricity costs associated with liquid-immersed transformers, DOE used marginal electricity prices. Marginal prices are those utilities pay for the last kilowatt-hour of electricity produced. A utility's marginal price may be higher or lower than its average price, depending on the relationships among capacity, generation, transmission, and distribution costs. The general structure of the hourly marginal cost equation divides the costs of electricity into (1) capacity components and (2) energy cost components. For each component DOE estimated the economic value for both no-load losses and load losses. The capacity components include generation and transmission capacity. Capacity components also include a reserve margin for ensuring system reliability, along with factors that account for system losses. Energy cost components include a marginal cost of supply that varies by the hour. DOE developed two methods to calculate marginal costs for the set of regions defined in the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS) electricity market module (EMM).[15] The method chosen depends on whether the utility is part of a traditionally regulated system, or part of a restructured system that includes functioning capacity markets.
DOE developed two sets of capacity costs to be applied to the two types of losses.

CC_{NLL} = the value of the capacity costs associated with no-load losses, and
CC_{LL} = the value of the capacity costs associated with load losses.

These terms are defined as follows.

$$CC_{NLL} = (1 + CM)(\beta C_G F_G + C_T F_T),$$

and

$$CC_{LL} = (1 + CM)(\beta C_G F_G + C_T F_T)\Delta P.$$

Where:

C_M	=	the reserve capacity margin;
β	=	a load adjustment factor, which is one plus the estimated system losses;
C_G	=	the cost in \$/kW of building new generation capacity;
F_G	=	the fixed charge rate used to calculate the annual revenue needed to support an investment in generation capacity;
C_T	=	the overnight cost in \$/kW of new transmission capacity;
F_T	=	the fixed charge rate for transmission investments; and
ΔP	=	the reduction in system peak load.

DOE calculated the various inputs of this equation as follows.

Capacity Margin (C_M): This factor represents the fraction of extra or reserve capacity needed to ensure system reliability per unit of additional capacity requirement. DOE used the industry standard of 15 percent.

Loss Adjustment Factor (β): The loss adjustment factor represents the fraction of electricity that is dissipated from the electrical system during generation and transmission. It is one plus the fractional losses in the system. DOE used a constant average value of 1.08, based on the regional transmission and distribution loss factors from the NEMS planning model.[3] The regional transmission and distribution loss factors are given in Table 8.3.3.

Table 8.3.3 Transmission and Distribution Loss Factors

EMM	1	2	3	4	5	6	7	8	9	10	11	12	13
β	1.070	1.065	1.072	1.068	1.088	1.080	1.080	1.068	1.068	1.081	1.093	1.093	1.093

Unit Generation Capacity Cost (C_G): This factor represents the overnight cost of building new generating capacity, as provided by NEMS.[15] The costs do not include financing charges; DOE added the cost of financing to the overnight costs assuming a cost of capital of 5 percent. Table 8.3.4 shows the rates for generating no-load loss and load loss capacity for regulated systems.

Table 8.3.4 Generation Capacity Costs

EMM Region	EMM Region	Load Loss Generation		No-load Loss Generation	
		Technology	$/kW-year	Technology	$/kW-year
1	ECAR	Combined Cycle	158.71	Advanced Coal	560.39
2	ERCOT	Combined Cycle	158.71	Advanced Coal	560.39
3	MAAC	Half & Half	359.55	Advanced Coal	560.39
4	MAIN	Half & Half	359.55	Advanced Coal	560.39
5	MAPP	Half & Half	359.55	Advanced Coal	560.39
6	NY	Combined Cycle	158.71	Combined Cycle	158.71
7	NE	Combined Cycle	158.71	Combined Cycle	158.71
8	FL	Combined Cycle	158.71	Advanced Coal	560.39
9	SERC	Half & Half	359.55	Advanced Coal	560.39
10	SPP	Half & Half	359.55	Advanced Coal	560.39
11	NPP	Combined Cycle	158.71	Advanced Coal	560.39
12	RA	Combined Cycle	158.71	Advanced Coal	560.39
13	CA	Combined Cycle	158.71	Advanced Coal	560.39

Generation Fixed Charge Rate (F_G): This fixed charge rate is used to calculate the annual revenue required to pay for investment in generation capacity. DOE used a value of 0.15.[3]

Unit Transmission Capacity Cost (C_T): This overnight cost per unit for an increment of new transmission capacity is provided by NEMS.[15]

Transmission Fixed Charge Rate (F_T): This rate is used to convert a lump-sum investment into an annual revenue requirement. DOE used a value of 0.12.[15]

Peak Load Reduction (ΔP): This reduction results from improved transformer efficiency. DOE used a statistical model to estimate the reduction consistent with the methodology used to model transformer hourly loads.

DOE preformed similar calculations for regions that have functioning capacity markets. For those regions DOE assumed that the value of generation capacity for load losses can be inferred from the capacity market results:

$$CC_{LL} = (1 + CM)(CAP + C_T F_T)\Delta P.$$

Capacity Market Rate (CAP): For systems having functioning capacity markets, DOE collected forward results for capacity market auctions from the website of each region's independent system operator (ISO).[16,17,18] Those values are shown in Table 8.3.5.

Table 8.3.5 Capacity Market Auction Results

EMM Region		ISO	Market Auction Results	
			Percent of Region Served *%*	**CAP** *$/KW-year*
1	ECAR	PJM	30	63.66
3	MAAC	PJM	100	64.45
4	MAIN	PJM	20	63.66
6	NY	NYISO	100	162.18
7	NE	NEISO	100	54.00
9	SERC	PJM	5	63.66

DOE developed two sets of energy costs to be applied to the two types of losses:

EC_{NLL} = the value of the capacity costs associated with no-load losses, and
EC_{LL} = the value of the capacity costs associated with load losses.

These terms can be further expressed as:

$$EC_{NLL} = \beta \in_{NLL} \textstyle\sum_h P(h),$$

and

$$EC_{LL} = \beta \in_{LL} \textstyle\sum_h P(h) e^2(h).$$

Where:

β = a load adjustment factor, which is one plus the estimated system losses;
$\in_{NLL}$ = the no-load (constant) loss rate;
$\in_{LL}$ = the load loss rate;
$P(h)$ = the hourly electricity price; and
$e^2(h)$ = the hourly transformer load.

Hourly Electricity Price (P(h)): To calculate the hourly price of electricity, DOE used the day-ahead market clearing price for regions having wholesale electricity markets, and system lambda values for all other regions. System lambda values, which are roughly equal to the operating cost of the next unit in line for dispatch, are filed by control area operators under Federal Energy Regulatory Commission (FERC) Form 714.[19] DOE used the most recent data available, from 2008, for both market prices and system lambdas.

Hourly Transformer Load (e^2(h)): DOE used a statistical model to represent hourly variations in transformer loading and the correlation with hourly-varying system electricity prices. The hourly load model is discussed in detail in chapter 7 of this TSD.

No-load Loss Rate ($\in_{NLL}$): This parameter, which provides the no-load loss rate of the selected transformers, is imported from the database of transformer design options developed in the engineering analysis (chapter 5).

Load Loss Rate ($\in_{LL}$): This parameter, which provides the load loss rate of the selected transformers, is imported from the database of transformer design options. The load loss rate is estimated while the transformer is fully loaded.

8.3.5.2 Monthly Marginal Electricity Price Model for Dry-Type Transformers

For C&I owners of dry-type transformers, DOE developed average marginal electricity prices from an analysis of marginal energy prices from tariffs for commercial buildings.[20, 21]

Electricity tariffs for C&I customers can be complex, incorporating block rates, seasonal rates, demand charges, and time-of-use rates. To calculate commercial electricity bills requires both the monthly consumption and demand; if the supplying utility imposes mandatory time-of-use (TOU) tariffs, consumption and demand data are required for each TOU period. Monthly billing data, consisting of electricity consumption, demand, and expenditures, are available from the EIA's Commercial Building Energy Consumption Survey for 1992 and 1995 survey years.[a] Those monthly data were processed using Coughlin et al.'s tariff bill calculation tools[20] to generate the corresponding monthly utility bill. DOE used the baseline utility bills to calculate average prices. Because the customer bill depends on both energy consumption and demand, separate marginal prices are needed to represent the effect of independently varying those two quantities. The monthly price of marginal electricity consumption (or demand) is calculated by decrementing the electricity consumption (or demand) and recalculating the bill. DOE calculated seasonal marginal energy prices (MPE) and marginal demand prices (MPD) for each building in the sample. The summer season is defined as the months May through September, and the winter season all other months.

DOE's tariff data were updated most recently in 2004. To convert to 2010 dollars, DOE used two datasets: (1) the report, *Average Regulated Retail Price of Electricity*[22] for 2004–2007, and (2) the *Edison Electric Institute (EEI) Typical Bills and Average Rate* reports for 2007[23] through 2010.[24,25]Based on those data, DOE used customer counts to calculate a weighted-average price escalation factor for each region. The customer counts came from the most recent EIA Form 861 data.[13] The EEI data cover only publicly owned companies. An analysis of EIA data for 2003–2006 showed that the rate of price escalation does not differ significantly for publicly versus privately owned utility companies, so DOE used the same escalation factors for both market sectors. Table 8.3.6 provides the average marginal energy and demand prices by season for the U.S. Census divisions. DOE dived the census divisions 8 (Mountain) and 9 (Pacific) into North and South sub regions to account for the impacts of climate on electricity prices.

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[a] See: Chapter 7, Energy Use and End-Use Load Characterization, for details regarding DOE's treatment of the CBECS sample.

Table 8.3.6 Average Seasonal Marginal Energy and Demand Prices by Census Division

Census Division	Marginal Energy Price *2010$/kWh*		Marginal Demand Price *2010$/kW*	
	Summer	**Winter**	**Summer**	**Winter**
1 (New England)	0.11	0.10	16.46	12.98
2 (Mid-Atlantic)	0.09	0.09	14.90	13.15
3 (East North Central)	0.06	0.05	14.04	12.70
4 (West North Central)	0.05	0.05	7.10	5.65
5 (South Atlantic)	0.07	0.07	10.12	9.83
6 (East South Central)	0.06	0.06	9.24	8.87
7 (West South Central)	0.09	0.07	7.18	5.89
8 (Mountain)North	0.05	0.05	3.97	3.94
8 (Mountain) South	0.07	0.08	9.90	9.49
9 (Pacific) North	0.06	0.06	3.48	3.48
9 (Pacific) South	0.11	0.11	9.97	4.54

8.3.6 Trends in Load Growth

The LCC analysis examines a cross-section of transformers. As part of an LCC sensitivity analysis, DOE applied a load growth trend to each new transformer. Spreadsheet users can choose among three scenarios using the “Transformer Load Growth/Year” drop-box on the *Summary* worksheet. The three scenarios are: no growth, one-half-percent-per-year growth, and one-percent-per-year growth. As the default scenario DOE used a growth trend of 0.5% for liquid-immersed and no growth trend for dry-type transformers.

8.3.7 Electricity Cost and Price Trends

For the relative change in electricity prices for future years, DOE used the price trends from the three forecast scenarios in the EIA’s *AEO2011*.[26] The default price trend scenario that DOE used in the LCC analysis is the trend in the *AEO2011* reference case. LCC spreadsheet users have the choice of using electricity price trends from the *AEO 2011* low-growth scenario, reference scenario, or high-growth scenario.

Figure 8.3.5 shows the trends for the three *AEO2011* price projections. Because *AEO2011* does not forecast beyond 2035, DOE extrapolated the values in later years from the price trends of the forecast from 2015 to 2035. This method of extrapolation is in line with methods the EIA currently uses to forecast fuel prices for the Federal Energy Management Program.

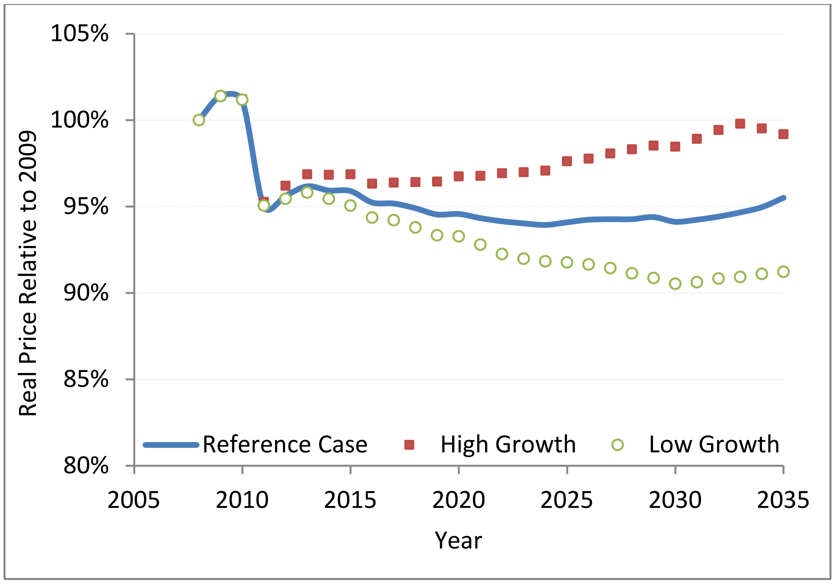

Figure 8.3.5 Electricity Price Forecasts from *AEO2011*

8.3.8 Discount Rate

The discount rate is the rate at which future expenditures are discounted to estimate their present value. DOE derived the discount rates for use in the transformer LCC analysis from estimates of the cost of capital for companies that purchase transformers. Following financial theory, the cost of capital can be interpreted as (1) the discount rate that should be used to reduce the future value of cash flows to be derived from a typical company project or investment; (2) the economic cost to a firm of attracting and retaining capital in a competitive environment; or (3) the return that investors require from their investment in a firm's debt or equity.[27] DOE used primarily the first interpretation. Because most companies use both debt and equity capital to fund investments; for most companies, the cost of capital is the weighted average of the cost to the firm of equity and debt financing.[28]

DOE estimated the cost of equity financing using the Capital Asset Pricing Model (CAPM). Among the most widely used models to estimate the cost of equity financing, the CAPM assumes that the cost of equity is proportional to the amount of systematic risk associated with a firm. The cost of equity financing tends to be high when a firm faces a large degree of systematic risk, and low when the firm faces a small degree of systematic risk. The degree of systematic risk facing a firm and the subsequent cost of equity financing are determined by several variables, including the risk coefficient of a firm (beta, or B); the expected return on risk-free assets (R_f); and the additional return expected on assets facing average market risk (which is known as the equity risk premium, or ERP). The beta indicates the degree of risk associated with a given firm relative to the level of risk (or price variability) in the overall stock market. Betas usually fall between 0.5 and 2.0. A firm having a beta of 0.5 faces half the risk of other stocks in the market; a firm having a beta of 2.0 faces twice the overall stock market risk. Following this approach, the cost of equity financing for a particular company is given by the following equation.

$$k_e = R_f + (B \times ERP).$$

Where:

k_e	=	the cost of equity for a company,
R_f	=	the expected return of a risk-free asset,
B	=	the beta of the company stock, and
ERP	=	the expected equity risk premium, or the amount by which investors expect the future return on equities to exceed that on a risk-free asset.

The cost of debt financing (k_d) is the yield or interest rate paid on money borrowed by a company (for example by selling bonds). As defined here, the cost of debt includes compensation for default risk and excludes deductions for taxes. DOE estimated the cost of debt for companies by adding a risk adjustment factor (R_a) to the current yield on long-term corporate bonds (the risk-free rate). DOE used this procedure to estimate current (and future) company costs to obtain debt financing. The adjustment factor is based on indicators of company risk, such as credit rating or variability of stock returns.

The discount rate of companies is the weighted average cost of debt and equity financing, less expected inflation. DOE estimated the discount rate using the equation:

$$k = (k_e \times w_e) + (k_d \times w_d).$$

Where:

k	=	the (nominal) cost of capital,
k_e and k_d	=	the expected rates of return on equity and debt, respectively, and
w_e and w_d	=	the proportions of equity and debt financing, respectively.

The real discount rate deducts expected inflation from the nominal rate. The expected return on risk-free assets, or the risk-free rate, is defined by the current yield on long-term government bonds. The ERP represents the difference between the expected (average) stock market return and the risk-free rate.[29] DOE adjusted the risk-free rate for inflation to arrive at the real risk-free rate, which it then used in the CAPM to estimate of the real discount rate as described above.[30]

Table 8.3.7 shows the typical owners of transformers, grouped by transformer type (the design lines DOE used in the engineering analysis). DOE used a sample of approximately 3,200 companies drawn from the various owner categories to represent transformer purchasers. DOE took the sample from the list of companies included on the Damodaran Online website.[31] DOE obtained the firm beta, the percent of debt and equity financing, the risk-free rate, and the equity risk premium from Damodaran Online.

Table 8.3.7 Typical Owners of Various Types of Transformers

Design Line	Typical Ownership Categories
1, 2, 3, 4	Electric utilities, both publicly and investor owned
5, 6, 7	Electric utilities, commercial property owners, commercial and industrial
8, 9, 10, 11, 12, 13A, 13B	Companies, government offices

Transformers are purchased and owned by electric utilities (publicly and investor-owned), C&I companies, the owners of commercial buildings (property owners), and all levels of government. DOE estimated the cost of debt financing for these companies from the 40 year geometric average of the 10-year Treasury note annual rate and the standard deviation of the stock price. Publicly owned utilities, including municipals and cooperatives, do not issue stock and tend to be financed with debt. DOE obtained the cost of debt for those companies from information provided in FERC Form 1 filings. Finally, for owners of government offices, the discount rate represents an average of the Federal rate and the State and local bond rates. DOE drew the Federal rate directly from the U.S. Office of Management and Budget discount rate for investments in energy efficiency in government buildings.[32] DOE estimated the State and local discount rates from the interest rates on State and local bonds between 1971 and 2010.[33]

Table 8.3.8 shows the average values DOE used for the parameters related to cost of equity financing and discount rate for industrial companies, commercial companies, commercial property owners, and investor-owned utilities. The risk-free rate and equity risk premium are constant across sectors in each year, but the cost of debt, percent debt financing, and systematic firm risk vary by sector.

Table 8.3.8 Variables Used to Estimate Discount Rates for the C&I Sector

Sector	Year	β	R_f %	ERP %	R_a %	w_e %	w_d %
Industrial Companies (SIC 1–4)	2005	1.03	3.47	3.89	1.50	79	21
	2006	1.00	3.44	4.55	2.00	81	19
	2007	1.03	3.74	3.80	2.00	78	22
	2008	1.10	4.21	2.19	4.00	73	27
	2009	1.06	4.15	3.20	4.00	76	24
	2010	1.12	6.74	3.23	2.50	74	26
Commercial Companies (SIC 5–8)	2005	0.88	3.47	3.89	1.25	80	20
	2006	0.88	3.44	4.55	1.25	78	22
	2007	0.90	3.74	3.80	1.25	75	25
	2008	0.95	4.21	2.19	3.00	64	36
	2009	0.94	4.15	3.20	4.00	68	32
	2010	0.98	6.74	3.23	2.00	62	38
Commercial Property Owners (SIC 6720)	2005	0.70	3.47	3.89	0.25	77	23
	2006	0.84	3.44	4.55	0.50	55	45
	2007	0.91	3.74	3.80	0.50	60	40
	2008	1.06	4.21	2.19	3.00	47	53
	2009	1.22	4.15	3.20	3.00	56	44
	2010	1.02	6.74	3.23	1.50	67	33
Utilities, Investor-Owned (SIC 49)	2005	0.86	3.47	3.89	0.50	61	39
	2006	0.92	3.44	4.55	0.25	61	39
	2007	0.88	3.74	3.80	0.25	60	40
	2008	0.79	4.21	2.19	1.00	50	50
	2009	0.76	4.15	3.20	1.50	51	49
	2010	0.75	6.74	3.23	1.00	53	47

*SIC codes refer to the U.S. Standard Industrial Classification system.

As mentioned above, the cost of capital may be viewed as the discount rate that should be used to reduce the future value of typical company project cash flows. It is a nominal discount rate, since anticipated future inflation is included in both stock and bond expected returns. Deducting expected inflation from the cost of capital provides estimates of the real discount rate by ownership category (Table 8.3.9). The mean real discount rate for these companies varies between 2.4 percent (government offices) and 5.4 percent (industrial companies).

Table 8.3.9 Real Discount Rates by Transformer Ownership Category

Ownership Category	SIC Code(s)*	Mean Real Discount Rate %	Standard Deviation %	Number of Observations
Industrial Companies	1–4	5.4	0.4	1866
Commercial Companies	5–8	4.6	1.4	1303
Commercial Property Owners	6720	4.6	0.4	3
Utilities, Investor-Owned	49	3.5	0.4	61
Utilities, Publicly Owned	n/a	3.8	0.3	7
Government Offices	n/a	2.4	2.2	40

*SIC codes refer to the U.S. Standard Industrial Classification system.

Because IOUs purchase the bulk of many of the transformer design lines evaluated here, the discount rates calculated for that sector (Table 8.3.9) are particularly important. DOE estimated that the average IOU real discount rate is 3.5 percent. That figure is an after-tax discount rate, representing the return required by such utilities to attract financing. Private financial data companies, including Ibbotson Associates, offer similar estimates. Using Ibbotson Associates debt, equity, standard deviation of stock price, and company beta statistics for 2008 in the electric, gas, and sanitary services sector (SIC 49), DOE estimates a similar discount rate of 3.84 percent.[27] DOE used the value of 3.5 percent, estimated from the company-level Damodaran data, because it is tailored specifically to IOUs, not the broader SIC 49 sector.

DOE's approach to estimating the cost of capital provides a measure of the spread as well as the average of the discount rate. DOE inferred the spread of the discount rate by ownership category from the standard deviation, which ranges from 0.4 percent to 2.2 percent (Table 8.3.10). Discount rates for publicly owned utilities and commercial property owners are narrowly concentrated around their mean values. Discount rates for C&I companies are dispersed across a broader range.

Table 8.3.10 Transformer Ownership by Design Line

Design Line	Property Owners %	Industrial Companies %	Commercial Companies %	Investor-Owned Utilities %	Publicly Owned Utilities %	Government Offices %
1	0.4	0.5	0.9	72.0	26.0	0.2
2	0.4	0.5	0.9	72.0	26.0	0.2
3	2.1	2.4	4.5	80.0	10.0	1.0
4	0.4	0.5	0.9	72.0	26.0	0.2
5	9.5	9.5	27.0	35.0	15.0	4.0
6	19.0	19.0	54.0	0	0	7.9
7	19.0	19.0	54.0	0	0	7.9
8	19.0	19.0	54.0	0	0	7.9
9	19.0	19.0	54.0	0	0	7.9
10	19.0	19.0	54.0	0	0	7.9
11	19.0	19.0	54.0	0	0	7.9
12	19.0	19.0	54.0	0	0	7.9
13A	19.0	19.0	54.0	0	0	7.9
13B	19.0	19.0	54.0	0	0	7.9

Source: DOE contractors.

Various combinations of commercial property owners and commercial, industrial, and utility buyers purchase the different transformer design lines included in the engineering analysis (chapter 5). Accordingly, DOE constructed the discount rates associated with any given design line from various combinations of discount rates for commercial property owners, commercial, industrial, and utility enterprises.[34] DOE estimated distributions of discount rates for the different design lines as a weighted average of the distributions for the ownership types.

8.3.9 Effective Date of Standard

The effective date of the revised energy efficiency standard for distribution transformers is four years after DOE issues the final rule. DOE assumes that it will issue the final rule in 2012, so the new standard will take effect in 2016. DOE calculated the LCC for all users as if each purchase of a new distribution transformer occurs in the year the standard takes effect. It based the cost of the equipment on that year; as stated above, however, DOE expresses all dollar values in 2010$.

8.3.10 Transformer Service Life

DOE defined distribution transformer service life as the age at which a transformer retires from service. DOE assumed, based on Barnes et al. (1996),[35] that the average life of distribution transformers is 32 years. This lifetime includes a constant failure rate of 0.5 percent per year due to lightning and other random failures unrelated to transformer age, and an additional corrosive failure rate of 0.5 percent per year starting at year 15. DOE adjusted the retirement distribution to maintain an average life of 32 years.

8.3.11 Maintenance Costs

Maintenance costs are those the customer incurs to maintain equipment operation. Maintenance costs are not associated with the replacement or repair of components that fail, but rather with general maintenance. DOE assumed that the cost for general maintenance will not change with increased efficiency. In practice, there is little scheduled maintenance for transformers beyond brief annual checks for dust buildup, vermin infestation, and accident or lightning damage.

8.3.12 Power Factor

The power factor of a transformer is the real power divided by the apparent power. Real power is the time average of the instantaneous product of voltage and current. Apparent power is the product of the root mean square (RMS) voltage times the RMS current. Transformer efficiency specifications, such as NEMA's TP 1-2002, assume a power factor of 1.0.[1] Therefore, DOE used a power factor of 1.0, both in calculating efficiency levels in the engineering analysis and when preparing efficiency levels.

In real-world installations, however, the loads experienced by distribution transformers are likely to have power factors of less than 1.0. Because the LCC analysis models transformers that are installed and operating in the field, DOE created the LCC spreadsheet with an adjustable power factor, enabling the incorporation of lower power factors. In the absence of any specific data or guidance on the appropriate power factor, DOE used 1.0 for this LCC analysis.

8.3.13 Default Scenario

DOE developed separate low, medium, and high scenarios for several key input parameters. For each of the key inputs, DOE chose the medium designation as the default scenario. The overall default scenario used in the LCC analysis has the following values.

- Transformer load growth per year: medium (one percent) for liquid-immersed; low (zero percent) for dry-type.
- Transformer loading (relative to current estimate): medium (zero percent).
- Electricity prices (relative to current estimate): medium (zero percent).
- Transformer customer A and B parameters: medium.
- Future energy price trend: *AEO2011* reference.

Other scenarios can be used to explore the sensitivities to variations of these key variables.

8.4 RESULTS OF LIFE-CYCLE COST ANALYSIS

This section presents LCC results for the candidate efficiency improvement levels evaluated for all 14 transformer design lines. Table 8.4.1 summarizes the seven candidate standard efficiency levels DOE evaluated for each of the 14 design lines examined for the preliminary analysis. The lowest efficiency level (EL) is baseline and current standard, and the highest is the most efficient design identified in the engineering analysis. The other six efficiency levels fall between those two bounds. DOE expresses all ELs in terms of efficiency, assuming no explicit or implicit technology. The column labeled “Base +” shows by how much a given standard level exceeds the baseline. DOE based the results presented in this section on the inputs described in section 8.3.

Table 8.4.1 Efficiency Levels Evaluated for Each Design Line

EL	Variable	Design Line													
		1	2	3	4	5	6	7	8	9	10	11	12	13A	13B
Baseline (Current DOE Standard) %		99.08	98.91	99.42	99.08	99.42	98.00	98.00	98.60	98.82	99.22	98.67	99.12	98.63	99.15
1	Base + %	0.08	0.09	0.06	0.08	0.06	0.23	0.23	0.20	0.11	0.07	0.14	0.09	0.06	0.04
	Efficiency %	99.16	99.00	99.48	99.16	99.48	98.23	98.23	98.80	98.93	99.29	98.81	99.21	98.69	99.19
2	Base + %	0.14	0.16	0.09	0.14	0.09	0.47	0.47	0.42	0.22	0.15	0.27	0.18	0.21	0.13
	Efficiency %	99.22	99.07	99.51	99.22	99.51	98.47	98.47	99.02	99.04	99.37	98.94	99.30	98.84	99.28
3	Base + %	0.17	0.20	0.12	0.17	0.12	0.60	0.60	0.54	0.33	0.23	0.39	0.27	0.34	0.23
	Efficiency %	99.25	99.11	99.54	99.25	99.54	98.60	98.60	99.14	99.15	99.45	99.06	99.39	98.97	99.38
4	Base + %	0.23	0.27	0.15	0.23	0.15	0.80	0.80	0.65	0.40	0.29	0.46	0.34	0.41	0.30
	Efficiency %	99.31	99.18	99.57	99.31	99.57	98.80	98.80	99.25	99.22	99.51	99.13	99.46	99.04	99.45
5	Base + %	0.34	0.40	0.19	0.34	0.19	0.93	0.93	0.72	0.57	0.36	0.65	0.41	0.62	0.37
	Efficiency %	99.42	99.31	99.61	99.42	99.61	98.93	98.93	99.32	99.39	99.58	99.32	99.53	99.25	99.52
6	Base + %	0.42	0.50	0.27	0.42	0.27	1.17	1.17	0.84	0.73	0.41	0.83	0.47	0.82	-99.15
	Efficiency %	99.50	99.41	99.69	99.50	99.69	99.17	99.17	99.44	99.55	99.63	99.50	99.59	99.45	
7	Base + %		0.56	0.31			1.44	1.44	0.98		0.45		0.51		
	Efficiency %		99.47	99.73			99.44	99.44	99.58		99.67		99.63		

One major impact of an energy efficiency standard is to change the set of transformer designs available for purchase and their corresponding loss characteristics: load losses (LL) and no-load losses (NL). This effect is illustrated in the “LL versus NL graph” (worksheet *LL versus NL* in the LCC spreadsheet).

Figure 8.4.2 provides an example of the “LL versus NL graph” from the LCC spreadsheet for design line 1, using EL 1. Because each design line has a unique set of engineering constraints, the LL-versus-NL graph for each will be different. This graph plots results of a Crystal Ball run for LCC. It shows different sets of designs by their LL at rated load and by their NL. Potential designs are shown as both small dots and small triangles. The selected designs not subject to standard constraints are plotted as circles. The designs subject to standards constraints are plotted as dots. As the required efficiency level increases, the cluster of selected designs moves to the left (to the area for lower losses. The efficiency level is defined at 50 percent load liquid-immersed and medium-voltage dry-type, and 35 percent load for low-voltage dry-type transformers, while the LL and NL for the design assumptions are defined by nameplate loading (100 percent). For those designs having higher LL, the heating from losses causes the actual efficiency to drop, shifting the design to the right in the graph.

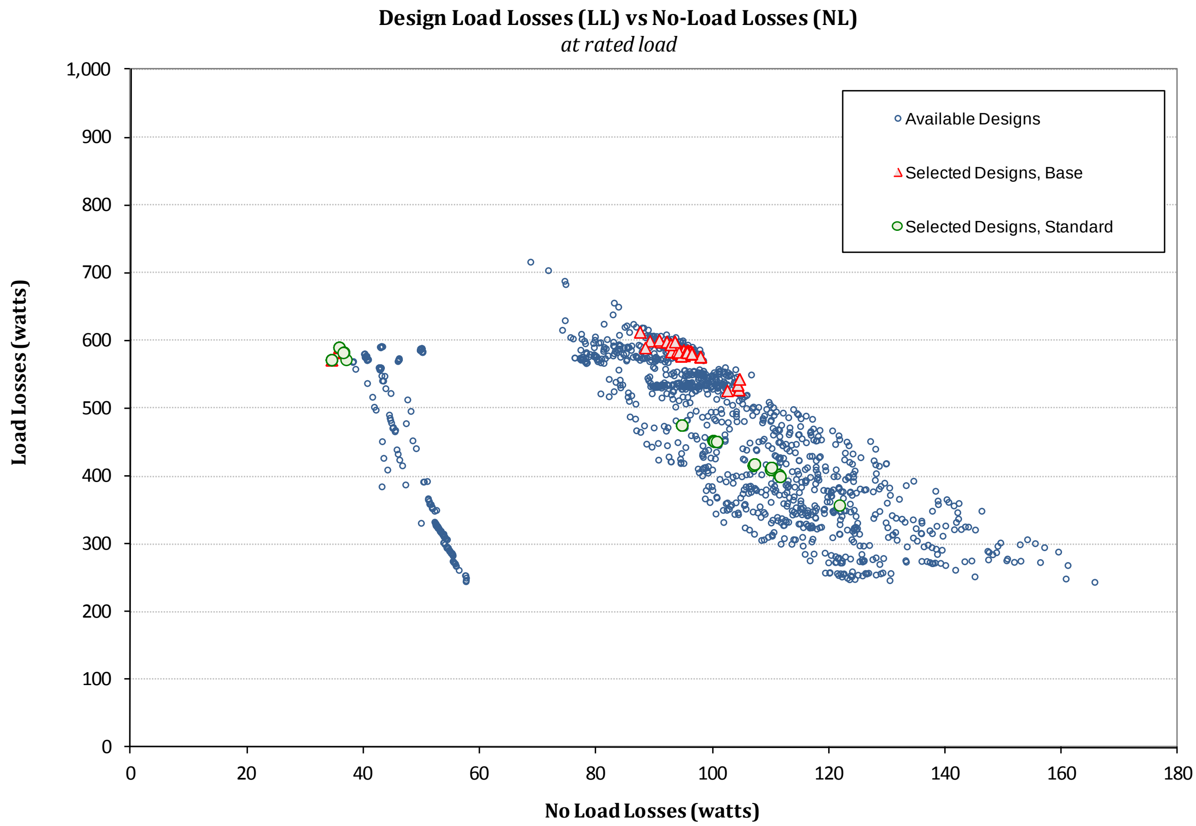

Figure 8.4.2 Design Load Losses versus No-Load Losses in the Base Case and Efficiency Level 1 for Design Line 1

Figure 8.4.3 illustrates the distribution of results of the LCC analysis for one design line at one EL. The LCC spreadsheet tool can generate graphical representations such as Figure 8.4.3 for each design line and efficiency level.

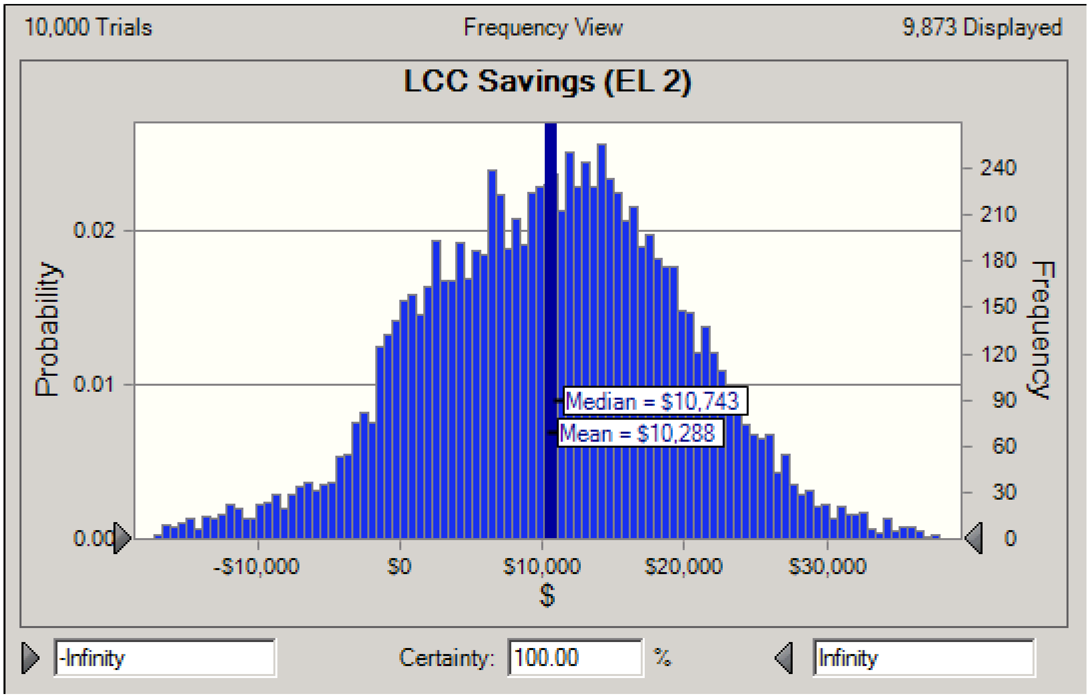

Figure 8.4.3 Distribution of Life-Cycle Cost Results for Design Line 2, Efficiency Level 2

The 14 tables that follow summarize the results from DOE's LCC analysis. For each evaluated design line and each EL, DOE presents the percent efficiency; the percent of evaluated transformer purchases that would experience negative, zero, and positive LCC savings when subject to the EL; and the mean LCC savings.

8.4.2 Results for Design Line 1

Table 8.4.2 summarizes results of the LCC analysis for the representative unit from design line 1, a 50-kVA, liquid-immersed, single-phase, pad-mounted transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.08 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $2,017; the installation cost was $2,130

Table 8.4.2 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 1

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net Increase in LCC (%)	57.94	4.77	4.77	8.00	13.63	55.36
Transformers with No Impact on LCC (%)	0.23	0.23	0.23	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	41.83	95.00	95.00	92.00	86.37	44.64
Mean LCC Savings ($)	36	641	641	532	629	50
Median LCC Savings ($)	-64	650	650	540	563	-104

8.4.3 Results for Design Line 2

Table 8.4.3 summarizes results of the LCC analysis for the representative unit from design line 2, a 25-kVA, liquid-immersed, single-phase, pole-mounted transformer. The average efficiency of the baseline units selected during the LCC analysis was 98.92 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $1,288; the installation cost was $1,636.

Table 8.4.3 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 2

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.00%	99.07%	99.11%	99.18%	99.31%	99.41%	99.46%
Transformers with Net Increase in LCC (%)	14.23	9.82	11.20	15.75	58.18	80.16	86.51
Transformers with No Impact on LCC (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	85.77	90.18	88.80	84.25	41.82	19.84	13.49
Mean LCC Savings ($)	309	338	300	250	-445	-736	-599
Median LCC Savings ($)	322	341	308	262	-91	-390	-535

8.4.4 Results for Design Line 3

Table 8.4.4 summarizes results of the LCC analysis for the representative unit from design line 3, a 500-kVA, liquid-immersed, single-phase distribution transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.43 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $7,710; the installation cost was $4,236.

Table 8.4.4 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 3

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.48%	99.51%	99.54%	99.57%	99.61%	99.69%	99.73%
Transformers with Net Increase in LCC (%)	15.68	11.17	5.33	4.02	3.87	7.60	25.07
Transformers with No Impact on LCC (%)	1.35	1.18	0.03	0.02	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	82.97	87.65	94.64	95.96	96.13	92.40	74.93
Mean LCC Savings ($)	2413	3831	5245	5591	6531	6780	4135
Median LCC Savings ($)	1665	3664	5304	5642	6593	6500	3301

8.4.5 Results for Design Line 4

Table 8.4.5 summarizes results of the LCC analysis for the representative unit from design line 4, a 150-kVA, liquid-immersed, three-phase distribution transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.09 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $5,512; the installation cost was $4,034.

Table 8.4.5 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 4

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%	99.60%
Transformers with Net Increase in LCC (%)	5.95	1.91	1.91	1.86	1.82	4.87	31.10
Transformers with No Impact on LCC (%)	0.58	0.58	0.58	0.58	0.17	0.00	0.00
Transformers with Net LCC Savings (%)	93.47	97.51	97.51	97.56	98.01	95.13	63.87
Mean LCC Savings ($)	862	3356.0	3356.0	3362.3	3437.2	3193	1274
Median LCC Savings ($)	670	3418.7	3418.7	3423.6	3489.8	3054	956

8.4.6 Results for Design Line 5

Table 8.4.6 summarizes results of the LCC analysis for the representative unit from design line 5, a 1,500-kVA, liquid-immersed, three-phase distribution transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.42 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $25,391; the installation cost was $8,438.

Table 8.4.6 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 5

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.48%	99.51%	99.54%	99.57%	99.61%	99.69%
Transformers with Net Increase in LCC (%)	19.05	13.15	10.41	7.77	7.88	39.92
Transformers with No Impact on LCC (%)	0.39	0.09	0.01	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	80.56	86.76	89.58	92.23	92.12	60.08
Mean LCC Savings ($)	7787	10288	11395	12513	12746	3626
Median LCC Savings ($)	8300	10741	11658	12666	12838	3083

8.4.7 Results for Design Line 6

Table 8.4.7 summarizes results of the LCC analysis for the representative unit from design line 6, a 25-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV basic impulse insulation level (BIL). The average efficiency of the baseline units selected during the LCC analysis was 98.02. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $1,192; the installation cost was $943.

Table 8.4.7 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 6

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net Increase in LCC (%)	51.85	64.97	71.51	17.59	17.57	36.16	93.36
Transformers with No Impact on LCC (%)	47.95	35.03	28.49	82.41	82.43	63.84	6.64
Transformers with Net LCC Savings (%)	0.20	0.00	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	-39	-55	-125	303	335	187	-881
Median LCC Savings ($)	-14	-96	-172	270	306	147	-940

8.4.8 Results for Design Line 7

Table 8.4.8 summarizes results of the LCC analysis for the representative unit from design line 7, a 75-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.04 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $2,900; the installation cost was $1,850.

Table 8.4.8 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 7

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net Increase in LCC (%)	1.8	1.8	1.8	2.0	2.8	3.7	46.4
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transformers with Net LCC Savings (%)	98.2	98.2	98.2	98.0	97.2	96.3	53.6
Mean LCC Savings ($)	1714	1714	1714	1793	2030	2270	270
Median LCC Savings ($)	1649	1649	1649	1724	1931	2174	123

8.4.9 Results for Design Line 8

Table 8.4.9 summarizes results of the LCC analysis for the representative unit from design line 8, a 300-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.62 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $6,748; the installation cost was $2,758.

Table 8.4.9 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 8

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	98.80%	99.02%	99.14%	99.25%	99.32%	99.44%	99.58%
Transformers with Net LCC Cost (%)	7.61	5.18	12.24	15.33	10.51	10.46	78.46
Transformers with Net LCC Benefit (%)	92.39	94.82	87.76	84.67	89.49	89.54	21.54
Transformers with No Change in LCC (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	1004	2476	2412	2625	4137	4145	-2812
Median LCC Savings ($)	882	2329	2211	2388	3858	3867	-3171

8.4.10 Results for Design Line 9

Table 8.4.10 summarizes results of the LCC analysis for the representative unit from design line 9, a 300-kVA, medium-voltage, dry-type, three-phase transformer with a 45-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.88 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $14,251; the installation cost was $3,294.

Table 8.4.10 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 9

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.93	99.04	99.15	99.22	99.39	99.55
Transformers with Net LCC Cost (%)	3.35	5.70	22.17	6.00	8.60	53.38
Transformers with Net LCC Benefit (%)	83.38	94.30	77.83	94.00	91.40	46.62
Transformers with No Change in LCC (%)	13.27	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	849	1659	1718	4194	4269	237
Median LCC Savings ($)	763	1447	1407	3885	3841	-365

8.4.11 Results for Design Line 10

Table 8.4.11 summarizes results of the LCC analysis for the representative unit from design line 10, a 1,500-kVA, medium-voltage, dry-type, three-phase transformer with a 45-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 99.24 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $43,361; the installation cost was $6,433.

Table 8.4.11 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 10

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.29	99.37	99.45	99.51	99.58	99.63
Transformers with Net LCC Cost (%)	0.66	16.72	44.00	60.06	66.77	84.78
Transformers with Net LCC Benefit (%)	98.82	83.28	56.00	39.94	33.23	15.22
Transformers with No Change in LCC (%)	0.52	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	4509	4791	2264	-1259	-3356	-12756
Median LCC Savings ($)	4266	4087	1127	-2228	-4733	-14507

8.4.12 Results for Design Line 11

Table 8.4.12 summarizes results of the LCC analysis for the representative unit from design line 11, a 300-kVA, medium-voltage, dry-type, three-phase transformer with a 95-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.70 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $21,469; the installation cost was $3,942.

Table 8.4.12 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 11

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.81	98.94	99.06	99.13	99.32	99.50
Transformers with Net LCC Cost (%)	20.61	49.54	32.06	25.66	39.46	76.13
Transformers with Net LCC Benefit (%)	79.38	50.46	67.94	74.34	60.54	23.87
Transformers with No Change in LCC (%)	0.01	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	1043	202	1464	2000	1371	-3160
Median LCC Savings ($)	920	16	1314	1754	984	-3739

8.4.13 Results for Design Line 12

Table 8.4.13 summarizes results of the LCC analysis for the representative unit from design line 12, a 1,500-kVA, medium-voltage, dry-type, three-phase transformer with a 95-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 99.14 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $54,971; the installation cost was $7,196.

Table 8.4.13 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 12

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.21	99.30	99.39	99.46	99.53	99.59	99.63
Transformers with Net LCC Cost (%)	6.72	7.76	23.46	18.12	25.10	48.09	81.09
Transformers with Net LCC Benefit (%)	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Transformers with No Change in LCC (%)	93.27	92.24	76.54	81.88	74.90	51.91	18.91
Mean LCC Savings ($)	4518	6934	6332	8860	8475	2063	-12420
Median LCC Savings ($)	4178	6402	5356	8003	7400	642	-14191

8.4.14 Results for Design Line 13A

Table 8.4.14 summarizes results of the LCC analysis for the representative unit from design line 13, a 2,000-kVA, medium-voltage, dry-type, three-phase transformer with a 125-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.64 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $27,141; the installation cost was $4,645.

Table 8.4.14 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 13A

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.69	98.84	98.97	99.04	99.25	99.45
Transformers with Net LCC Cost (%)	52.17	43.00	74.81	64.38	64.41	97.08
Transformers with Net LCC Benefit (%)	47.81	57.00	25.19	35.62	35.59	2.92
Transformers with No Change in LCC (%)	0.02	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	25	414	-1318	-846	-1084	-11077
Median LCC Savings ($)	-43	224	-1543	-1153	-1392	-11526

8.4.15 Results for Design Line 13B

Table 8.4.14 summarizes results of the LCC analysis for the representative unit from design line 13, a 2,000-kVA, medium-voltage, dry-type, three-phase transformer with a 125-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 99.16 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $70,884; the installation cost was $8,783.

Table 8.4.15 Results of Life-Cycle Cost Analysis: Representative Unit, Design Line 13B

	Efficiency Level				
	1	**2**	**3**	**4**	**5**
Efficiency (%)	99.19	99.28	99.38	99.45	99.52
Transformers with Net LCC Cost (%)	28.50	26.34	57.60	52.74	67.20
Transformers with Net LCC Benefit (%)	71.30	73.66	42.40	47.26	32.80
Transformers with No Change in LCC (%)	0.20	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	2733	4709	-520	384	-5407
Median LCC Savings ($)	2361	3899	-1807	-923	-6757

8.5 LIFE-CYCLE COST SENSITIVITY ANALYSIS

DOE recognizes that all engineering and economic analyses involve some uncertainty. To minimize that uncertainty, DOE strives to use the best techniques and the best data at its disposal. To account for the widest possible set of scenarios, DOE used distributions of values for key inputs to the analysis. For some variables, DOE went one step further by incorporating in the LCC spreadsheet the ability to repeat a given LCC analysis using values different from the default set used to produce DOE's results.

Detailed descriptions of all of the LCC input variables are included in the discussion of inputs in section 8.3, with additional information in chapters 6 and 7. This section focuses on five key variables and the effect on the LCC results if they are assigned different values. The five variables and the location of their descriptive materials are:

1. percentage of transformers purchased using evaluation of parameters A and B (see section 8.3.1);
2. transformer loading relative to current estimate (see chapter 7);
3. electricity price (see chapter 7);
4. load growth trends (see section 8.3.6);
5. equipment price (see chapter 6);
6. electricity price trends (see section 8.3.7); and

7. the exclusion of transformers designed with ZDMH, M2, H1 and amorphous core steels.

This analysis examines how sensitive the LCC results are to changes in key DOE assumptions. For this NOPR, DOE conducted the sensitivity analysis on design lines 1, 7, and 12. Because the analysis treats each variable independently, the default values remain in effect for all variables except the one being examined. Sensitivity results should always be compared to default results. Each of the first six variables has three values—low, medium, and high—that are described in the previous sections discussing each individual input variable.

The variable that characterizes the percentage of transformers purchased using evaluation of parameters A and B uses the same set of low and high values, but different medium values, for liquid-immersed and dry-type transformers. The low value represents a scenario in which no transformer purchases are evaluated (the non-evaluating scenario). The high value represents a scenario in which all transformer purchases are evaluated. The medium value for liquid-immersed transformers represents a scenario in which 10 percent of purchases are evaluated. The medium value for low-voltage dry-type transformers represents a scenario in which 2 percent of purchases are evaluated. The medium value for medium-voltage, dry-type transformers represents a scenario in which 2 percent of purchases are evaluated.

For transformer loading, the medium scenario represents the output of the load simulation described in chapter 7. The low scenario for liquid-immersed and medium-voltage dry-type distribution transformers decreases the median RMS load to 25 percent; the high scenario increases it to 50 percent; for low-voltage dry-type distribution transformers the low scenario decreased the median RMS load to 16 percent, the high scenario increases it to 35 percent. For load growth, the annual low, medium, and high scenarios are 0 percent, 0.5 percent, and 1 percent, respectively, the default case for liquid-immersed distribution transformers is the medium case, the default for both low-voltage and medium-voltage dry-type transformers is the low case. Electricity price trends use the *AEO2011* low, reference, and high growth scenarios.

8.5.1 Sensitivity Results for Design Line 1

The representative unit from design line 1 is a 50-kVA, liquid-immersed, single-phase, pad-mounted transformer. The average efficiency of the baseline units selected in the base case during the LCC analysis was 99.08 percent. The customer equipment cost before installation, which includes the manufacturer selling price, shipping costs, distributor markup, and sales tax, was $2,017; the installation cost was $2,130.

Table 8.5.1 and Figure 8.5.1 illustrate the LCC sensitivity to changes in the six user-selectable variables. For all variables, each sensitivity run causes some change in the LCC results. For design line 1, the change in percentage of transformer loading results in the most significant changes in LCC savings for all ELs examined. The reason that transformer loading is so important is that it is related directly to the amount of electricity that passes through a transformer. When the load on a transformer is increased, the load losses also increase. Thus at higher loading levels the economic gains from the reduction in losses are significant compared to the baseline.

Table 8.5.1 Effects of Changed Variables on Life-Cycle Cost Savings for Representative Unit, Design Line 1

Scenario	Efficiency Level 1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Baseline	36	641	641	532	629	50
Low A & B Distribution	-17	643	643	530	629	49
High A & B Distribution	449	635	635	524	606	22
Low Loading	-156	647	647	477	359	-401
High Loading	611	633	633	693	1445	1413
Low Electricity Price	6	557	557	438	504	-88
High Electricity Price	61	731	731	622	752	184
No Load Growth	-21	645	645	515	550	-82
High Load Growth	95	643	643	548	715	193
Low Equipment Price	90	701	701	617	769	312
High Equipment Price	-91	444	444	269	259	-591
Low Electricity Price Trend	17	592	592	475	552	-36
High Electricity Price Trend	51	696	696	585	703	130
Materials Exclusion	-19	-310	-552	NA*	NA	NA

*The higher EL can not be met without amorphous steel

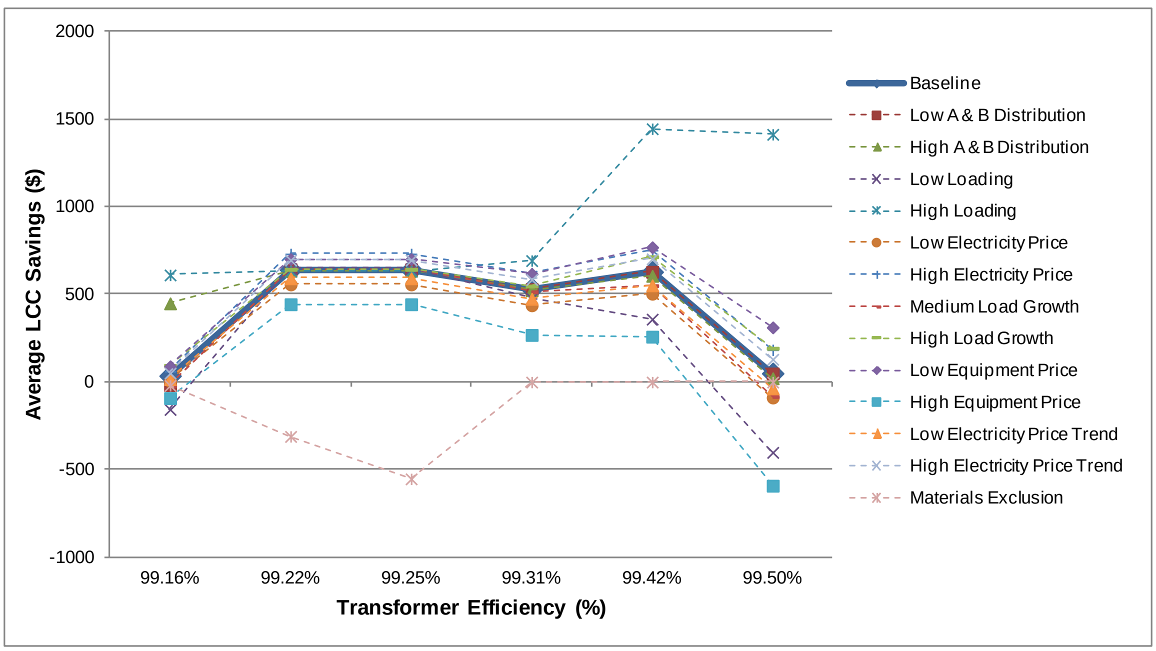

Figure 8.5.1 Average Life-Cycle Cost Savings (2010$) by Scenario for Design Line 1

8.5.2 Sensitivity Results for Design Line 7

The representative unit from design line 7 is a 75-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV basic BIL. The average efficiency of the baseline units selected in the base case during the LCC analysis was 98.04 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $2,900; the installation cost was $1,850.

Table 8.5.2 and Figure 8.5.2 illustrate the LCC sensitivity to changes in the six user-selectable variables for design line 7. For all variables, each sensitivity run causes some change in the LCC results. For design line 7, low equipment price, high electricity cost, high transformer loading result in significantly larger changes in the LCC savings than do the other variables for all ELs examined.

Table 8.5.2 Effects of Changed Variables on Life-Cycle Cost Savings for Representative Unit, Design Line 7

	Efficiency Level						
Scenario	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Baseline	1714	1714	1714	1793	2030	2270	270
Low A & B Distribution	1789	1789	1789	1869	2123	2383	394
High A & B Distribution	1843	1843	1843	1928	2095	2343	354
Low Loading	1701	1701	1701	1757	2149	2205	-44
High Loading	1982	1982	1982	2119	2065	2772	1354
Low Electricity Price	1529	1529	1529	1597	1767	1980	-20
High Electricity Price	2051	2051	2051	2145	2479	2786	808
No Load Growth	1790	1790	1790	1871	2123	2383	394
High Load Growth	1790	1790	1790	1871	2123	2383	394
Low Equipment Price	2041	2041	2041	2141	2512	2827	1292
High Equipment Price	1422	1422	1422	1511	1640	1785	-1101
Low Electricity Price Trend	1592	1592	1592	1660	1868	2073	48
High Electricity Price Trend	1957	1957	1957	2048	2338	2644	685

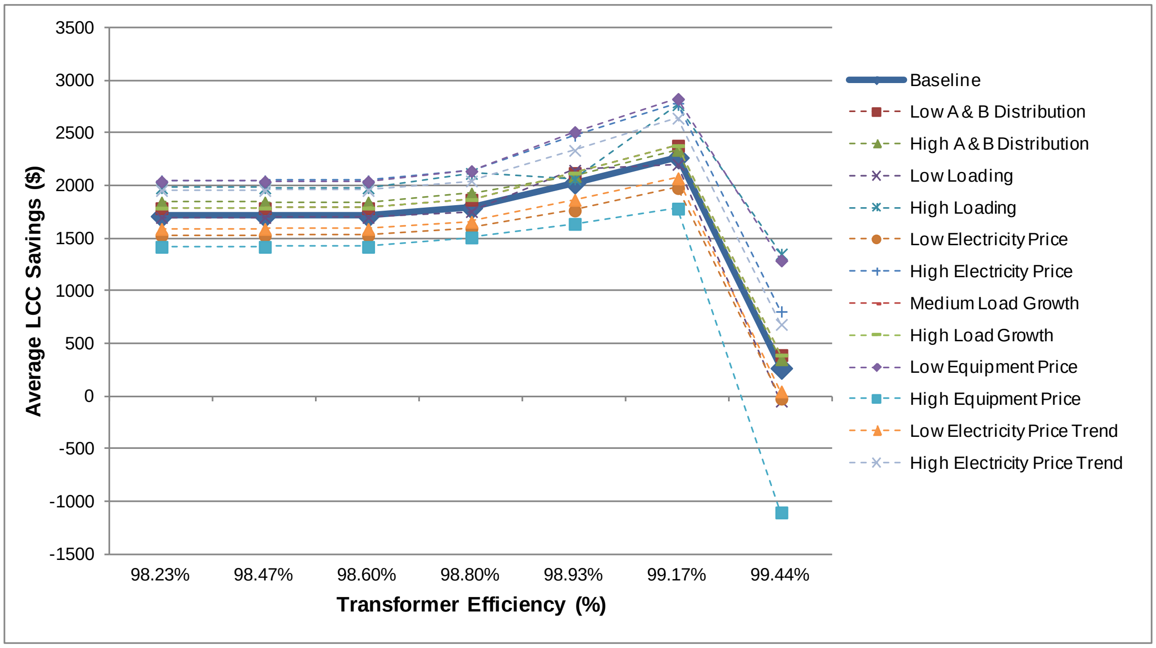

Figure 8.5.2 Average Life-Cycle Cost Savings (2010$) by Scenario for Design Line 7

8.5.3 Sensitivity Results for Design Line 12

The representative unit from design line 13 is a 1500-kVA, medium-voltage, dry-type, three-phase transformer with a 95-kV BIL. The average efficiency of the baseline units selected in the base case during the LCC analysis was 98.66 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $27,141; the installation cost was $4,645.

Table 8.5.3 and Figure 8.5.3 illustrate the LCC sensitivity to changes in the six user-selectable variables for design line 13. For all the variables, each sensitivity run causes some change in the LCC results. The changes tend to increase with the efficiency of the EL. For design line 13, the change in percentage of transformer loading and equipment price results in the most significant increase in LCC savings for all ELs examined. Transformer loading is a measure the amount of electricity that passes through a transformer. When the load on a transformer is increased, the load losses also increase; at higher loading levels the economic gains from the reduction in losses are greater when compared to the baseline.

Table 8.5.3 Effects of Changed Variables on Life-Cycle Cost Savings (2010$) for Representative Unit, Design Line 12

Scenario	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Baseline	4518	6934	6332	8860	8475	2063	-12420
Low A & B Distribution	4825	7460	7048	9801	9552	3241	-11194
High A & B Distribution	3955	6288	6883	8709	8453	2289	-12277
Low Loading	4496	6138	5975	8907	7146	-806	-16139
High Loading	5674	10729	9815	12054	15498	13214	967
Low Electricity Price	4801	7431	7022	9775	9524	3214	-11221
High Electricity Price	4801	7431	7022	9775	9524	3214	-11221
Medium Load Growth	4984	8156	7649	10270	10839	5422	-8528
High Load Growth	5188	8971	8355	10826	12322	7913	-5487
Low Equipment Price	5021	7317	11925	14475	15571	11667	1108
High Equipment Price	3128	3328	-1206	653	-1253	-10916	-32389
Low Electricity Price Trend	4191	6280	5191	7396	6714	100	-14508
High Electricity Price Trend	5313	8399	8561	11775	11889	5834	-8457

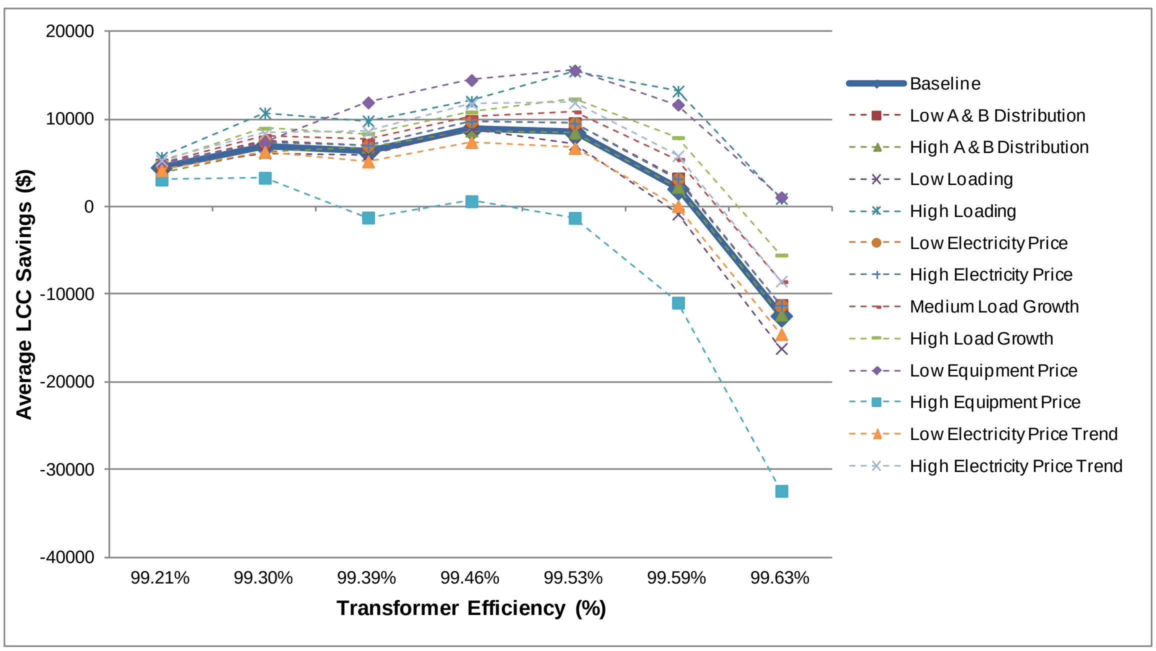

Figure 8.5.3 Average Life-Cycle Cost Savings (2010$) by Scenario for Design Line 13

8.6 PAYBACK PERIOD

The payback period (PBP) analysis is commonly used to evaluate investment decisions. A more energy efficient device usually costs more to purchase than a device of standard energy efficiency. The more efficient device usually costs less to operate, however, because of its lower energy consumption. The payback period is the time (usually expressed in years) it takes to recover the additional first cost of the efficient device through its energy cost savings. Because the LCC analysis uses distributions of inputs, DOE gives PBP results in the form of distributions.

8.6.1 Definition

The PBP is the ratio of the increase in purchase expense (for a more efficient design compared to a less efficient design) to the decrease in annual operating expenditures for the more efficient design. This calculation provides what is known as a *simple* payback period because it does not take into account changes in operating costs over time. PBP is found using the equation:

$$PBP = \frac{\Delta FC}{\Delta OC}.$$

Where:

ΔFC = installed purchase price (first cost) of a transformer that satisfies the given EL minus the first cost of a transformer in the absence of the standard (assumes the transformer meeting the standard is more expensive than the transformer not subject to the standard) (2010$), and

ΔOC = operating cost of the transformer not subject to the standard minus operating cost of the transformer subject to the standard (assumes the transformer meeting the efficiency level has lower energy consumption, and hence lower operating cost). Because ΔOC is expressed in annual terms, PBP is expressed in years.

DOE calculates the PBP both for a distribution of transformers and for an average transformer. For the national average transformer, the average values of the increase in first cost and the operating-cost savings are used to calculate the PBP.

8.6.2 Inputs to Payback Period

The inputs to PBP are: (1) the purchase expense, otherwise known as the total installed customer cost, or first cost, for each selected design; and (2) the annual (first-year) operating expenditures for each selected design. The inputs to the purchase expense are the equipment price and the installation cost including appropriate markups. The inputs to operating costs are the annual (first-year) energy consumption and the electricity price. The distributional PBP uses the same inputs as the LCC analysis described in section 8.3, except that, because this is a simple payback, the electricity price DOE uses is only for the year the standard takes effect, assumed here to be 2016.

8.6.3 Issues Regarding Baseline Scenario

DOE's default assumption for the baseline scenario was that some percentage of transformer purchase decisions are based on evaluating the total owning cost (TOC) through parameters A and B. Specifically, the default assumptions are that 50 percent of purchase decisions for liquid-immersed, 2 percent for low-voltage dry-type transformers, and 10 to 20 percent for medium-voltage, dry-type transformers use TOC-type evaluations that incorporate various distributions of values for parameters A and B. Especially at the lower efficiency levels (ELs) that DOE evaluated, transformer purchases based on TOC may not satisfy the basic PBP assumptions of higher purchase price and lower operating costs for the transformers subject to the EL. When those basic assumptions are not satisfied, the traditional PBP calculation loses its validity.

For example, a current transformer purchase decision (subject to the current standards) based on TOC may have a first cost ($\Delta FC = 0$) that is identical to a transformer that just meets EL 1. In addition, the transformer that meets the standard may have a different operating cost from a transformer that does not. In such a situation, PBP = 0. In another example, a current transformer purchase decision based on TOC may result in a transformer that costs more to purchase and install but consumes less electricity than a transformer that just meets baseline. In this case, the PBP calculation for the standards case is nonsensical, because it would imply a negative payback period.

DOE's method of calculating PBP is shown below.

ΔFC = $FC(standard)$ - $FC(baseline)$
(ΔFC usually is positive.)

ΔOC = $OC(standard)$ - $OC(baseline)$
(ΔOC usually is negative.)

PBP = $-\Delta FC/\Delta OC$
(For the usually positive ΔFC and the usually negative ΔOC, PBP is positive.)

Because ΔFC can be 0 or negative, and because ΔOC also can be 0 or negative, there are nine possible situations, which can be grouped into five computational cases. Table 8.6.1 shows the possible relationships between ΔFC and ΔOC and the resultant effect on PBP.

Table 8.6.1 Possible ΔFC and ΔOC Combinations for Payback Period Analysis

Case #	Possible Cases	Effect on PBP Calculation
1	$\Delta FC > 0$ and $\Delta OC < 0$	Well-defined PBP.
2	$\Delta FC = 0$ and $\Delta OC = 0$	Unaffected by the standard.
3	$\Delta FC < 0$ and $\Delta OC = 0$, or $\Delta FC > 0$ and $\Delta OC = 0$	Division by 0: PBP is undefined.
4	$\Delta FC = 0$ and $\Delta OC > 0$, or $\Delta FC = 0$ and $\Delta OC < 0$	PBP = 0.
5	$\Delta FC < 0$ and $\Delta OC < 0$, or $\Delta FC > 0$ and $\Delta OC > 0$, or $\Delta FC < 0$ and $\Delta OC > 0$	Not valid: negative or double-negative PBP, PBP = 0.

8.6.4 Results of Payback Period Analysis

Tables 8.6.2 through 8.6.14 illustrate, for each of the 14 design lines and their 7 efficiency levels, the mean PBP and the percentage of the 10,000 Monte Carlo simulations to which the PBP calculation applies. For every EL for each design line, the sum of the categories "Transformers Having Well-Defined Payback Period," and "Transformers Having Undefined Payback Period" should equal 100 percent.[a] As the efficiency of the ELs increases, so does the percentage of purchase decisions in which the PBP is well defined. DOE calculates the PBP both for a distribution of transformers. The PBP for the national average transformer is calculated using the average values of the first cost increase and operating cost savings.

Figure 8.6.1 illustrates the full PBP results from the Monte Carlo simulation as a histogram for one example design line and EL. The LCC spreadsheet tool can be used to generate similar histograms for all design lines and each EL.

[a]For simplicity of presentation, cases 3, 4, and 5, shown in Table 8.6.1, were combined into the "Transformers Having Undefined Payback Period" category in Tables 8.6.2 through 8.6.14.

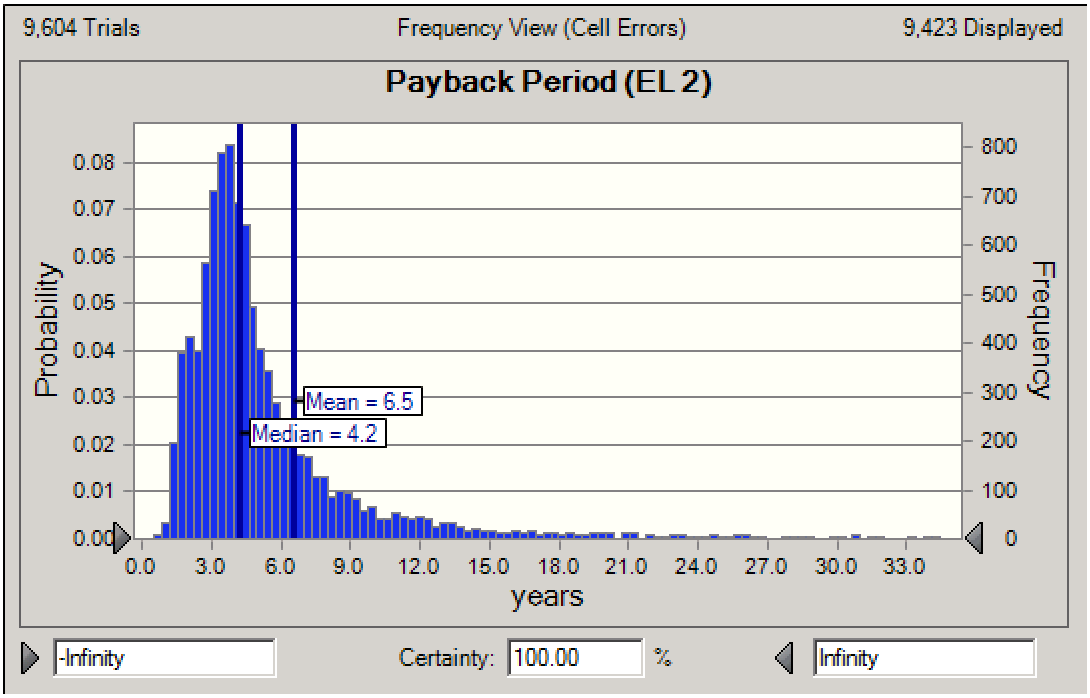

Figure 8.6.1 Distribution of Payback Period Results for Design Line 5, Efficiency Level 2

8.6.5 Results for Design Line 1

Table 8.6.2 summarizes results of the PBP analysis for the representative unit from design line 1, a 50-kVA, liquid-immersed, single-phase, pad-mounted transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.08 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $2,017; the installation cost was $2,130.

Table 8.6.2 Results of Payback Period Analysis: Representative Unit, Design Line 1

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	32.2	8.2	8.2	10.4	12.0	19.9
Median Payback (Years)	20.2	7.9	7.9	10.0	11.5	19.2
Transformers having Well Defined Payback (%)	85.02	99.77	99.77	99.89	99.99	99.95
Transformers having Undefined Payback (%)	14.98	0.23	0.23	0.11	0.01	0.05
Mean Retail Cost ($)	2,244	2,446	2,446	2,549	2,802	3,333
Mean Installation Costs ($)	2,230	2,271	2,271	2,344	2,415	2,606
Mean Operating Costs ($)	209	156	156	153	132	126
Mean Incremental First Cost ($)	327	569	569	746	1,070	1,792
Mean Operating Cost Savings ($)	18	71	71	74	95	100

Payback of Average Transformer	18.2	8.0	8.0	10.1	11.2	17.8

8.6.6 Results for Design Line 2

Table 8.6.3 summarizes results of the PBP analysis for the representative unit from design line 2, a 25-kVA, liquid-immersed, single-phase, pole-mounted transformer. The average efficiency of the baseline units selected during the LCC analysis was 98.92 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $1,288; the installation cost was $1,636.

Table 8.6.3 Results of Payback Period Analysis: Representative Unit, Design Line 2

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	10.0	9.7	11.3	13.4	27.9	32.7	30.3
Median Payback (Years)	6.9	8.0	9.5	11.5	18.7	24.3	26.3
Transformers having Well Defined Payback (%)	98.55	99.93	99.71	99.83	99.75	99.77	99.90
Transformers having Undefined Payback (%)	1.45	0.07	0.29	0.17	0.25	0.23	0.10
Mean Retail Cost ($)	1,437	1,480	1,530	1,598	1,846	2,052	2,577
Mean Installation Costs ($)	1722	1761	1790	1859	2500	2678	2093
Mean Operating Costs ($)	101	95	93	89	79	75	71
Mean Incremental First Cost ($)	235	317	396	533	1,422	1,807	1,746
Mean Operating Cost Savings ($)	34	40	41	46	55	60	64
Payback of Average Transformer	7.0	8.0	9.6	11.7	25.8	30.2	27.4

8.6.7 Results for Design Line 3

Table 8.6.4 summarizes results of the PBP analysis for the representative unit from design line 3, a 500-kVA, liquid-immersed, single-phase distribution transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.43 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $7,710; the installation cost was $4,236.

Table 8.6.4 Results of Payback Period Analysis: Representative Unit, Design Line 3

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	9.2	6.7	5.6	5.5	6.1	9.6	15.4
Median Payback (Years)	6.3	4.0	4.6	4.7	5.2	8.1	13.3
Transformers having Well Defined Payback (%)	94.83	96.53	99.82	99.97	100.00	99.91	99.65
Transformers having Undefined Payback (%)	5.17	3.47	0.18	0.03	0.00	0.09	0.35
Mean Retail Cost ($)	8,550	8,942	9,535	9,678	10,280	12,499	15,917

Mean Installation Costs ($)	4,333	4,311	4,370	4,402	4,523	4,997	5,679
Mean Operating Costs ($)	1,203	1,085	966	939	857	714	650
Mean Incremental First Cost ($)	938	1,308	1,960	2,135	2,858	5,550	9,650
Mean Operating Cost Savings ($)	201	319	439	465	547	690	754
Payback of Average Transformer	4.7	4.1	4.5	4.6	5.2	8.0	12.8

8.6.8 Results for Design Line 4

Table 8.6.5 summarizes results of the PBP analysis for the representative unit from design line 4, a 150-kVA, liquid-immersed, three-phase distribution transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.09 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $5,512; the installation cost was $4,034.

Table 8.6.5 Results of Payback Period Analysis: Representative Unit, Design Line 4

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	6.6	4.4	4.4	4.4	4.6	8.2	15.1
Median Payback (Years)	5.0	4.1	4.1	4.1	4.3	7.9	14.6
Transformers having Well Defined Payback (%)	99.37	99.27	99.27	99.33	99.81	99.94	94.96
Transformers having Undefined Payback (%)	0.63	0.73	0.73	0.67	0.19	0.06	0.01
Mean Retail Cost ($)	5,894	6,443	6,443	6,451	6,536	7,615	10,601
Mean Installation Costs ($)	4,090	4,184	4,184	4,183	4,223	4,584	4,709
Mean Operating Costs ($)	668	483	483	482	471	400	334
Mean Incremental First Cost ($)	438	1,081	1,081	1,088	1,214	2,653	5,763
Mean Operating Cost Savings ($)	76	261	261	262	274	344	414
Payback of Average Transformer	5.7	4.1	4.1	4.1	4.4	7.7	13.9

8.6.9 Results for Design Line 5

Table 8.6.6 summarizes results of the PBP analysis for the representative unit from design line 5, a 1,500-kVA, liquid-immersed, three-phase distribution transformer. The average efficiency of the baseline units selected during the LCC analysis was 99.42 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, and sales tax, was $25,391; the installation cost was $8,438.

Table 8.6.6 Results of Payback Period Analysis: Representative Unit, Design Line 5

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	7.0	6.5	7.8	7.8	9.7	18.7
Median Payback (Years)	4.0	4.2	5.7	6.3	8.3	16.9

Transformers having Well Defined Payback (%)	91.63	96.04	98.89	99.82	99.97	100.00
Transformers having Undefined Payback (%)	8.37	3.96	1.11	0.18	0.03	0.00
Mean Retail Cost ($)	28,574	29,040	30,872	31,980	35,448	56,798
Mean Installation Costs ($)	8,551	8,631	8,875	9,030	9,498	9,834
Mean Operating Costs ($)	3,407	3,259	3,105	2,994	2,802	2,185
Mean Incremental First Cost ($)	3,296	3,842	5,918	7,181	11,116	32,803
Mean Operating Cost Savings ($)	718	866	1,020	1,131	1,323	1,940
Payback of Average Transformer	4.6	4.4	5.8	6.3	8.4	16.9

8.6.10 Results for Design Line 6

Table 8.6.7 summarizes results of the PBP analysis for the representative unit from design line 6, a 25-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV basic impulse insulation level (BIL). The average efficiency of the baseline units selected during the LCC analysis was 98.02. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $1,192; the installation cost was $943.

Table 8.6.7 Results of Payback Period Analysis: Representative Unit, Design Line 6

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	26.8	29.8	29.0	13.1	13.2	16.7	33.2
Median Payback (Years)	16.9	22.7	24.7	12.8	13.0	16.3	32.4
Transformers having Well Defined Payback (%)	91.32	99.04	99.94	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	8.68	0.96	0.06	0.00	0.00	0.00	0.00
Mean Retail Cost ($)	1,208	1,272	1,403	1,683	1,743	1,977	2,864
Mean Installation Costs ($)	1,202	1,305	1,369	1,026	1,059	1,164	1,490
Mean Operating Costs ($)	140	132	125	106	99	89	81
Mean Incremental First Cost ($)	275	442	638	573	667	1,006	2,220
Mean Operating Cost Savings ($)	13	21	28	47	54	64	72
Payback of Average Transformer	21.6	21.2	23.1	12.1	12.3	15.6	30.7

8.6.11 Results for Design Line 7

Table 8.6.8 summarizes results of the PBP analysis for the representative unit from design line 7, a 75-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.04 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $2,900; the installation cost was $1,850.

Table 8.6.8 Results of Payback Period Analysis: Representative Unit, Design Line 7

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	4.7	4.7	4.7	4.9	5.9	7.0	18.6
Median Payback (Years)	4.5	4.5	4.5	4.7	5.8	6.9	18.1
Transformers having Well Defined Payback (%)	100	100	100	100	100	100	100
Transformers having Undefined Payback (%)	0	0	0	0	0	0	0
Mean Retail Cost	3,537	3,537	3,537	3,583	3,881	4,161	6,049
Mean Installation Costs ($)	1,743	1,743	1,743	1,761	1,731	1,839	2,362
Mean Operating Costs ($)	222	222	222	214	187	153	131
Mean Incremental First Cost ($)	531	531	531	594	863	1,250	3,662
Mean Operating Cost Savings ($)	121	121	121	129	156	190	212
Payback of Average Transformer	4.4	4.4	4.4	4.6	5.5	6.6	17.3

8.6.12 Results for Design Line 8

Table 8.6.9 summarizes results of the PBP analysis for the representative unit from design line 8, a 300-kVA, low-voltage, dry-type, three-phase transformer with a 10-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.67 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $6,748; the installation cost was $2,758.

Table 8.6.9 Results of Payback Period Analysis: Representative Unit, Design Line 8

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	9.3	8.6	11.5	12.6	11.2	11.2	25.1
Median Payback (Years)	8.8	8.4	11.1	12.3	11.0	11.0	24.5
Transformers having Well Defined Payback (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mean Retail Cost ($)	7,463	8,411	9,700	10,851	11,784	11,782	19,031
Mean Installation Costs ($)	2,850	2,999	3,126	3,221	3,158	3,158	3,905
Mean Operating Costs ($)	739	600	527	449	320	320	264
Mean Incremental First Cost ($)	807	1,905	3,321	4,567	5,437	5,435	13,430
Mean Operating Cost Savings ($)	98	236	309	388	517	517	573
Payback of Average Transformer	8.3	8.1	10.7	11.8	10.5	10.5	23.4

8.6.13 Results for Design Line 9

Table 8.6.10 summarizes results of the PBP analysis for the representative unit from design line 9, a 300-kVA, medium-voltage, dry-type, three-phase transformer with a 45-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.86 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $14,251; the installation cost was $3,294.

Table 8.6.10 Results of Payback Period Analysis: Representative Unit, Design Line 9

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	3.6	7.3	13.7	9.0	10.1	20.4
Median Payback (Years)	2.6	6.2	11.1	8.7	9.8	19.1
Transformers having Well Defined Payback (%)	85.45	99.98	99.92	100.00	100.00	100.00
Transformers having Undefined Payback (%)	14.55	0.02	0.08	0.00	0.00	0.00
Mean Rretail Price ($)	14,388	14,994	16,391	17,256	18,027	23,021
Mean Installation Costs ($)	3,295	3,311	3,435	3,674	3,806	4,431
Mean Operating Costs ($)	861	784	699	505	452	367
Mean Incremental First Cost ($)	139	760	2,282	3,386	4,289	9,907
Mean Operating Cost Savings ($)	53	130	216	409	462	547
Payback of Average Transformer	2.6	5.8	10.6	8.3	9.3	18.1

8.6.14 Results for Design Line 10

Table 8.6.11 summarizes results of the PBP analysis for the representative unit from design line 10, a 1,500-kVA, medium-voltage, dry-type, three-phase transformer with a 45-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 99.28 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $43,361; the installation cost was $6,433.

Table 8.6.11 Results of Payback Period Analysis: Representative Unit, Design Line 10

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	1.5	11.7	20.6	21.4	23.4	30.9
Median Payback (Years)	1.1	8.8	16.4	20.5	22.0	28.4
Transformers having Well Defined Payback (%)	99.45	98.98	99.82	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.55	1.02	0.18	0.00	0.00	0.00
Mean Pretail Price ($)	43,657	46,918	54,571	65,497	70,424	81,370
Mean Installation Costs ($)	6,416	6,834	7,441	8,036	8,390	9,104

Mean Operating Costs ($)	2,550	2,337	2,028	1,596	1,424	1,303
Mean Incremental First Cost ($)	279	3,958	12,218	23,739	29,021	40,680
Mean Operating Cost Savings ($)	258	472	781	1,213	1,384	1,506
Payback of Average Transformer	1.1	8.4	15.6	19.6	21.0	27.0

8.6.15 Results for Design Line 11

Table 8.6.12 summarizes results of the PBP analysis for the representative unit from design line 11, a 300-kVA, medium-voltage, dry-type, three-phase transformer with a 95-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.70 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $21,469; the installation cost was $3,942.

Table 8.6.12 Results of Payback Period Analysis: Representative Unit, Design Line 11

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	12.8	23.3	16.8	14.6	17.3	25.9
Median Payback (Years)	10.7	17.6	14.7	14.1	16.6	24.5
Transformers having Well Defined Payback (%)	99.01	98.49	99.98	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.99	1.51	0.02	0.00	0.00	0.00
Mean Pretail Price ($)	22,724	24,638	26,367	26,683	29,377	35,473
Mean Installation Costs ($)	4,030	4,326	4,306	4,296	4,622	5,206
Mean Operating Costs ($)	966	892	731	686	557	441
Mean Incremental First Cost ($)	1,342	3,553	5,261	5,568	8,587	15,267
Mean Operating Cost Savings ($)	129	203	363	408	537	653
Payback of Average Transformer	10.4	17.5	14.5	13.6	16.0	23.4

8.6.16 Results for Design Line 12

Table 8.6.13 summarizes results of the PBP analysis for the representative unit from design line 12, a 1,500-kVA, medium-voltage, dry-type, three-phase transformer with a 95-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 99.14 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $54,971; the installation cost was $7,196.

Table 8.6.13 Results of Payback Period Analysis: Representative Unit, Design Line 12

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	7.5	9.6	14.4	13.3	14.6	19.0	27.1

Median Payback (Years)	6.3	9.0	13.5	13.0	14.1	18.2	25.9
Transformers having Well Defined Payback (%)	99.29	100.00	99.99	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.71	0.00	0.01	0.00	0.00	0.00	0.00
Mean Retail Price ($)	57,380	60,978	68,566	71,895	76,909	86,085	101,590
Mean Installation Costs ($)	7,113	7,231	7,971	8,316	8,637	9,318	10,270
Mean Operating Costs ($)	2,976	2,645	2,228	1,894	1,627	1,441	1,335
Mean Incremental First Cost ($)	2,326	6,042	14,370	18,045	23,379	33,236	49,694
Mean Operating Cost Savings ($)	370	701	1,118	1,452	1,719	1,905	2,011
Payback of Average Transformer	6.3	8.6	12.9	12.4	13.6	17.4	24.7

8.6.17 Results for Design Line 13A

Table 8.6.14 summarizes results of the PBP analysis for the representative unit from design line 13, a 2,000-kVA, medium-voltage, dry-type, three-phase transformer with a 125-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 98.66 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $27,141; the installation cost was $4,645.

Table 8.6.14 Results of Payback Period Analysis: Representative Unit, Design Line 13A

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	24.8	18.8	26.9	22.2	22.0	38.7
Median Payback (Years)	16.5	16.8	24.4	21.7	21.3	37.1
Transformers having Well Defined Payback (%)	88.59	99.93	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	11.41	0.07	0.00	0.00	0.00	0.00
Mean Retail Price ($)	27,902	29,552	32,891	35,577	37,918	48,703
Mean Installation Costs ($)	4,752	4,832	5,103	5,093	5,309	6,280
Mean Operating Costs ($)	1,082	967	866	696	571	476
Mean Incremental First Cost ($)	868	2,598	6,207	8,884	11,441	23,197
Mean Operating Cost Savings ($)	48	162	264	434	559	654
Payback of Average Transformer	18.0	16.0	23.5	20.5	20.5	35.5

8.6.18 Results for Design Line 13B

Table 8.6.14 summarizes results of the PBP analysis for the representative unit from design line 13, a 2,000-kVA, medium-voltage, dry-type, three-phase transformer with a 125-kV BIL. The average efficiency of the baseline units selected during the LCC analysis was 99.18 percent. The customer equipment cost before installation, which includes the manufacturer selling price, distributor markup, contractor markup, and sales tax, was $70,884; the installation cost was $8,783.

Table 8.6.15 Results of Payback Period Analysis: Representative Unit, Design Line 13B

	Efficiency Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	11.9	13.8	21.3	19.8	22.4
Median Payback (Years)	4.6	12.5	19.9	19.3	21.9
Transformers having Well Defined Payback (%)	88.05	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	11.95	0.00	0.00	0.00	0.00
Mean Retail Price ($)	72,108	80,007	91,898	103,613	116,322
Mean Installation Costs ($)	8,958	8,997	9,629	9,652	10,305
Mean Operating Costs ($)	4,082	3,547	3,154	2,471	2,063
Mean Incremental First Cost ($)	1,398	9,337	21,859	33,599	46,959
Mean Operating Cost Savings ($)	223	758	1,151	1,834	2,242
Payback of Average Transformer	6.3	12.3	19.0	18.3	20.9

8.7 REBUTTABLE PRESUMPTION

The rebuttable presumption is a simplified method of determining the economic justification of a proposed energy efficiency standard. In evaluating the rebuttable presumption, DOE estimates the additional cost of purchasing a more efficient, standard-compliant equipment, then compares that cost to the value of the energy savings during the first year of operation as determined by the applicable test procedure. The rebuttable presumption that such a standard level is economically justified is satisfied if the additional first cost is less than three times the value of the energy savings (when the rebuttable payback period is less than three years).

The payback period for the rebuttable presumption differs from payback periods presented in earlier parts of this chapter in two important ways.

- The rebuttable presumption payback period uses test procedure loading levels to evaluate losses, rather than DOE's estimate of in-service loading conditions.

- The payback period considers only the value of energy savings, not total operating costs. In the case of distribution transformers, however, DOE estimates that the change in operating costs is due solely to energy savings.

There are three key inputs to calculation of the payback period for the rebuttable presumption: (1) average efficiency, (2) average installed cost, and (3) the cost of electricity. Given the average efficiency of a transformer, DOE calculated the losses on the transformer assuming the loading conditions from the test procedure. Multiplying the losses times the cost of electricity provided the operating cost. Then, dividing incremental operating costs into incremental installed cost provided the estimate of the rebuttable payback period.

Tables 8.7.1 through 8.7.3 show the inputs to the calculation of the rebuttable presumption payback period. Table 8.7.1 shows the average transformer efficiency as a function of design line and standard level for EL 1 through EL 7. This is the average efficiency as determined by the customer choice model from the LCC calculation. The customer choice model provides a range of transformer design efficiencies that depends on a distribution of customer choices with respect to the value that customers place on reducing transformer design losses. Table 8.7.2 shows the average installed cost of the transformer as a function of both design line and EL. The average marginal cost of electricity is a function of transformer type: for liquid-immersed transformers it is estimated to be 0.67 $/kWh; for dry-type transformers, 0.059 $/kWh. The difference between the two marginal costs of electricity reflects the fact that liquid-immersed transformers tend to be owned by utilities, which pay the wholesale (rather than retail) cost of electricity. Table 8.7.3 shows the first-year operating cost for the transformer, which is the annual losses calculated based on the test procedure assumptions times the average marginal cost of electricity.

Table 8.7.1 Average Transformer Efficiency %

Design Line	Rated Capacity *kVA*	Efficiency Level							
		Base	1	2	3	4	5	6	7
1	50	99.08	99.17	99.30	99.30	99.32	99.43	99.50	
2	25	98.92	99.02	99.09	99.12	99.18	99.34	99.41	99.47
3	500	99.43	99.49	99.52	99.56	99.57	99.62	99.69	99.73
4	150	99.09	99.19	99.41	99.41	99.41	99.43	99.51	99.60
5	1500	99.43	99.49	99.52	99.55	99.57	99.61	99.69	
6	25	98.02	98.33	98.50	98.65	98.81	98.94	99.18	99.45
7	75	98.04	98.77	98.77	98.77	98.82	98.95	99.18	99.44
8	300	98.62	98.81	99.02	99.15	99.26	99.45	99.45	99.58
9	300	98.88	98.96	99.08	99.19	99.33	99.41	99.56	
10	1500	99.24	99.31	99.40	99.46	99.53	99.58	99.64	
11	300	98.70	98.83	98.95	99.10	99.14	99.32	99.51	
12	1500	99.14	99.22	99.31	99.40	99.46	99.53	99.59	99.63
13A	300	98.64	98.71	98.85	98.98	99.08	99.27	99.46	
13B	2000	99.16	99.20	99.29	99.38	99.46	99.55		

Table 8.7.2 Average Transformer Installed Cost *($2010)*

Design Line	Rated Capacity *kVA*	Efficiency Level Base	1	2	3	4	5	6	7
1	50	4,147	4,474	4,716	4,716	4,893	5,217	5,939	
2	25	2,924	3,159	3,241	3,320	3,457	4,346	4,731	4,670
3	500	11,945	12,883	13,253	13,905	14,081	14,803	17,495	21,596
4	150	9,546	9,984	10,626	10,626	10,634	10,760	12,199	15,310
5	1500	33,829	37,125	37,671	39,747	41,010	44,946	66,632	
6	25	2,135	2,410	2,577	2,773	2,708	2,802	3,141	4,354
7	75	4,749	5,281	5,281	5,281	5,344	5,613	6,000	8,411
8	300	9,505	10,312	11,410	12,826	14,072	14,942	14,940	22,935
9	300	17,545	17,704	18,506	20,332	20,931	21,936	28,495	
10	1500	49,796	50,510	54,698	65,502	73,850	79,271	94,669	
11	300	25,411	26,754	28,964	30,672	30,979	33,999	40,678	
12	1500	62,167	64,493	68,209	76,537	80,211	85,546	95,403	111,860
13A	300	31,786	32,654	34,425	37,994	40,670	43,227	54,983	
13B	2000	79,667	81,065	89,004	102,084	113,266	126,624		

Table 8.7.3 First-Year Operating Cost for Rebuttable Presumption Based on DOE Test Procedure *($2010)*

Design Line	Rated Capacity *kVA*	Efficiency Level Base	1	2	3	4	5	6	7
1	50	261	238	193	193	189	160	147	
2	25	158	133	125	122	115	98	90	84
3	500	1,571	1,379	1,281	1,159	1,125	1,016	831	737
4	150	788	708	516	516	516	502	426	355
5	1500	4,648	3,996	3,790	3,587	3,420	3,157	2,489	
6	25	176	154	143	134	131	122	106	88
7	75	411	281	281	281	271	255	206	153
8	300	1,042	895	750	659	582	455	454	347
9	300	1,216	1,132	1,000	873	745	657	484	
10	1500	3,903	3,553	3,028	2,679	2,402	2,097	1,768	
11	300	1,393	1,252	1,110	986	948	746	546	
12	1500	4,368	3,955	3,524	3,097	2,787	2,380	2,046	1,823
13A	300	1,422	1,347	1,205	1,069	1,001	792	583	
13B	2000	5,583	5,232	4,662	4,023	3,721	3,049		

Table 8.7.4 shows the rebuttable payback period as a function of design line and standard level. The data indicate the rebuttable presumption is for design lines 9 and 10. For design lines 9 and 10 the rebuttable presumption payback is satisfied for efficiency level 1 only.

Table 8.7.4 Payback Period for Rebuttable Presumption

Design Line	Rated Capacity *kVA*	Efficiency Level						
		1	**2**	**3**	**4**	**5**	**6**	**7**
1	50	17.1	8.3	8.3	10.2	10.7	16.3	
2	25	9.5	9.9	11.0	12.5	17.3	21.3	22.6
3	500	5.8	4.5	4.9	4.9	5.2	7.6	11.9
4	150	4.7	3.9	3.9	4.0	4.2	7.4	13.5
5	1500	4.3	4.2	5.5	5.9	7.5	15.2	
6	25	11.4	13.9	15.9	13.5	13.0	15.0	26.5
7	75	4.2	4.2	4.2	4.4	5.8	6.4	14.9
8	300	5.7	6.8	9.0	10.4	9.7	9.7	20.2
9	300	1.9*	4.6	8.4	7.5	8.2	15.5	
10	1500	1.9	5.7	13.3	16.6	16.9	21.8	
11	300	9.5	13.0	13.4	13.0	13.9	18.8	
12	1500	5.5	7.4	11.9	12.0	12.3	14.9	20.3
13A	300	11.9	12.7	18.2	22.2	19.1	28.9	
13B	2000	5.2	10.2	14.9	19.1	19.4		

* Values less than 3 indicate a rebuttable presumption that the standard level is economically justified.

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CHAPTER 9. SHIPMENTS ANALYSIS

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CHAPTER 9. SHIPMENTS ANALYSIS

9.1 INTRODUCTION

The U.S. Department of Energy (DOE) analyzes shipments of affected equipment as a part of establishing a new or amended energy efficiency standard. Estimates of shipments are a necessary input to calculating the national energy savings (NES) and net present value (NPV) of an investment in more efficient equipment. Both the NES and NPV, discussed in chapter 10, are needed to analyze the impacts of proposed standards. Shipments are also a necessary input to the manufacturer impact analysis (MIA), which DOE conducts to prepare its notice of proposed rulemaking. The MIA estimates the impact of potential efficiency standards on manufacturers of the affected equipment, in this case distribution transformers, and assesses the direct impact of each potential standard on employment and manufacturing capacity. This chapter describes the method DOE used to project annual shipments of liquid-immersed and dry-type distribution transformers under base- and standards-case efficiency levels. It also presents results of the shipments analysis.

DOE developed a shipments model to predict shipments of distribution transformers. The shipments model estimates the rate at which the in-service stock of transformers may be replaced by new, more efficient units after an energy conservation standard becomes effective. The core of the shipments analysis is an accounting model that DOE developed to simulate how current and future purchases are incorporated into and gradually replace the in-service stock. In estimating the effects of potential new standards on shipments, the model accounts for the combined effects on the purchase decision of increases in purchase price and decreases in annual operating costs, and consumer income.

The shipments model is prepared as a Microsoft Excel spreadsheet that is accessible on DOE's website (http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html). Appendix 10A of this technical support document describes how to access and utilize the spreadsheets that support the shipments model and other models related to the national impact analysis (described in chapter 10). The rest of this chapter explains the shipments model in more detail. Section 9.2 describes the methodology that underlay development of the model. Section 9.3 describes the data inputs and model calibration; the effects on shipments of changes in purchase price and operating costs, and consumer income; and the affected stock of transformers. Section 9.4 presents the model results for both liquid-immersed and dry-type distribution transformers for the seven trial standard levels identified for this rulemaking.

9.2 MODEL OVERVIEW

In developing the shipments model, DOE used forecasts of shipments for a base case and each standards case to estimate the annual sales and in-service stock of transformers throughout the forecast period (2016–2045). DOE chose an accounting method to prepare shipment scenarios for the base case and several standard levels. The estimate included the age distribution of each transformer type (classified according to equipment class) and size. The model uses annual transformer sales and the age distribution of the in-service stock to calculate equipment costs for the NPV and energy use for the NES, respectively. The model keeps track of the age and replacement of transformer capacity, given a projection of future growth in transformer sales.

To estimate total transformer shipments, the model estimates shipments for specific market segments and then aggregates those results. DOE accounted for two market segments: (1) new capacity, and (2) replacement shipments going into existing structures. Replacements occur when transformers break down, corrode, are struck by lightning, or otherwise need to be replaced. Purchases for new capacity occur due to increases in electricity use that may be driven by increasing population, commercial and industrial activity, or growth in electricity distribution systems.

Figure 9.2.1 presents a flow diagram of the shipments model part of the NES and NPV spreadsheets that underlie the national impact analysis (chapter 10). In the diagram, the arrows show the interconnectivity of data exchanges between calculations. Inputs are shown as parallelograms. As data flow from these inputs, they may be integrated into intermediate results (shown as rectangles) or, via integrating sums or differences (shown as circles), into major outputs (shown as boxes having wavy bottom edges).

The model starts with an estimate of the overall growth in transformer capacity and then estimates shipments for particular equipment classes using estimates of the relative market share for various design and size categories. The steps for the shipments analysis are listed below.

1. Collection and processing of available data on shipments of distribution transformers.
2. Construction of an aggregate shipments backcast, based on shipments and electricity consumption data, to obtain an annual estimate of historical total capacity shipped.
3. Construction of aggregate shipments forecast, to estimate future annual shipments in the base case.
4. Development of separate market shares for liquid-immersed and dry-type transformers from the total capacity shipped.
5. Modeling of purchase price elasticity to evaluate the impact that higher purchase prices due to a standard will have on future shipments.
6. Accounting of sales and in-service transformer stocks to develop an annual age distribution of in-service stock from shipments estimates and a retirement function.

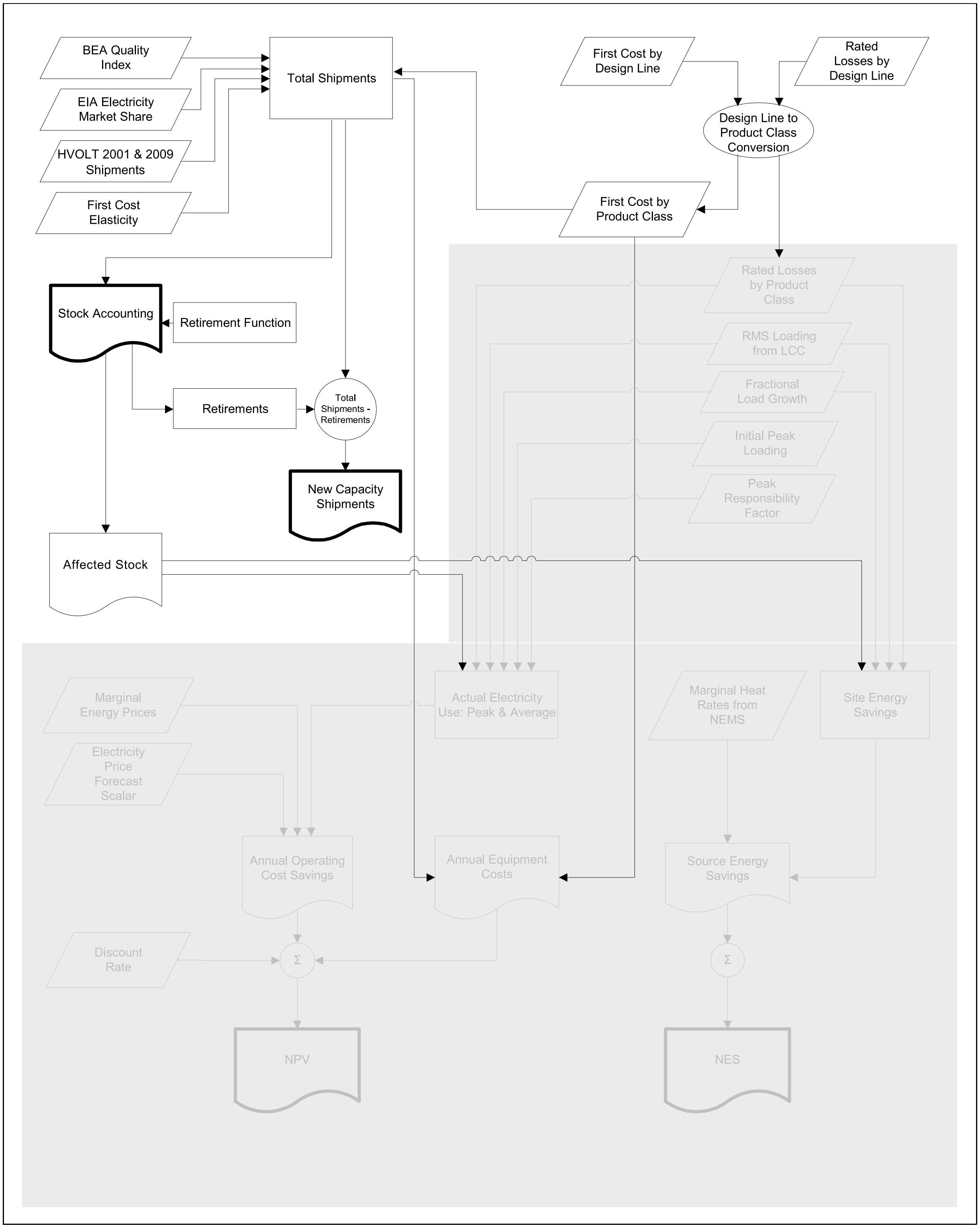

Figure 9.2.1 Flowchart of Shipments Model

9.3 INPUTS TO MODEL

The shipments model utilizes both internal and external inputs. Internal inputs comprise quantities that are calculated from the steps described above. External inputs are acquired exogenously. The outputs of the shipments analysis are estimates of annual shipments and the age distribution of in-service transformer stock. The specific inputs are listed below.

1. Shipments data, which include external estimates of transformer shipments and the quantity index of transformers manufactured. The external estimates used in this analysis are sales data for 2001 and 2009. The quantity index of transformers manufactured is available for 1977–2008.
2. Shipments backcast, an estimate of transformer capacity shipped before 2009.
3. Shipments forecast, an estimate of distribution transformers shipped after 2009.
4. Long-term price elasticity of transformer purchases.
5. Annual market shares of liquid-immersed and dry-type transformers shipped, categorized by capacity.
6. Stock accounting to develop the age distribution of the current year's in-service transformer stock based on the previous year's stock and shipments.
7. Retirement function that provides an estimate of the probability that a transformer will be replaced as a function of its age.
8. Refurbishments and Rewinds, to accurately capture whether or not a unit is replaced upon failure or refurbished/rewound.
9. The initial stock of transformers at the start of the stock-accounting calculation (in 1950).
9. Effective date of standard (2016) is a key input for determining the stock of transformers impacted by a standard.
10. Affected stock is a key output of the shipments model that is an input for the NES/NPV calculation and represents that percentage of the in-service transformer stock that may be impacted by a standard.

Each of these inputs is described in detail in the following sections.

9.3.1 Shipments Data

DOE uses data regarding historical transformer shipments to calibrate a forecast of future shipments and in-service stocks. These data are key inputs to the national impact analysis (chapter 10), because changes in shipments and in-service stock create nearly proportional changes in the estimated energy savings from a standard.

DOE obtained an estimate of sales (for the entire market for distribution transformers) for 2009, disaggregated by transformer type (whether liquid-immersed or dry-type) and kilovolt-ampere (kVA) rating.[1,2] DOE used a similar sales estimate, compiled by the same source, for 2001. In the absence of data regarding historical shipments for years other than 2001 and 2009, DOE explored other means of developing estimates of transformer sales. The historical quantity index for power distribution and specialty transformer manufacturing (North American Industry Classification System [NAICS] code 335311) for 1977–2008 is available from the U.S. Bureau of Economic Affairs (BEA). The BEA quantity index provides information on changes to aggregate shipments from 1977 to 2008.[3] Using the sales estimates for 2001 and 2009 as reference points and the BEA quantity index data, DOE estimated aggregate transformer shipments from 1977 to 2008.

Table 9.3.1 presents DOE's estimates of both units shipment and overall megavolt-amperes (MVA) shipped, and the approximate value of those shipments. Total sales for the distribution transformer industry were about $1.9 billion in 2009.

Table 9.3.1 Estimated Shipments of Distribution Transformers, 2009

Equipment Class		**Units Shipped**	**Capacity Shipped** ***MVA***	**Value of Shipments** ***million 2009$***
1	Liquid-immersed, medium-voltage, single-phase	683,726	21,994	714.8
2	Liquid-immersed, medium-voltage, three-phase	49,739	32,266	786.0
3	Dry-type, low-voltage, single-phase	17,740	647	22.0
4	Dry-type, low-voltage, three-phase	206,929	15,778	394.4
5	Dry-type, medium-voltage, single-phase, 20–45 kV BIL*	709	23	0.7
6	Dry-type, medium-voltage, three-phase, 20–45 kV BIL	522	257	6.2
7	Dry-type, medium-voltage, single-phase, 46–95 kV BIL	546	23	0.8
8	Dry-type, medium-voltage, three-phase, 46–95 kV BIL	2,074	3,655	98.7
9	Dry-type, medium-voltage, single-phase, ≥ 96 kV BIL	202	9	0.3
10	Dry-type, medium-voltage, three-phase, ≥ 96 kV BIL	1,286	2,206	66.2

Source: HVOLT Inc.
* BIL = basic impulse insulation level.

Table 9.3.2 presents the shipment estimates for 2009 for medium-voltage liquid-immersed distribution transformers categorized by capacity and by equipment type –whether single- or three-phase.

Table 9.3.2 Estimated Shipments of Liquid-Immersed Medium-Voltage Transformers, 2009

Single-Phase		Three-Phase	
Capacity *kVA*	**Units Shipped**	**Capacity *kVA***	**Units Shipped**
10	58,090	15	-
15	169,083	30	-
25	243,583	45	1,635
37.5	41,755	75	4,269
50	119,455	112.5	898
75	26,338	150	8,445
100	18,679	225	2,239
167	4,357	300	8,347
250	1,905	500	7,563
333	238	750	3,982
500	238	1,000	3,606
667	5	1,500	3,345
833	-	2,000	2,839
–	-	2,500	2,571
Total Units	**683,726**	**Total Units**	**49,739**
Total MVA	**21,994**	**Total MVA**	**32,266**

Source: HVOLT Inc.

Table 9.3.3 gives the shipment estimates for 2009 for dry-type medium-voltage distribution transformers categorized by capacity and by whether single- or three-phase.

Table 9.3.3 Estimated Shipments of Dry-Type, Medium-Voltage Transformers, 2009

Capacity *kVA*	Single-Phase Units Shipped by BIL* *kV*			Capacity *kVA*	Three-Phase Units Shipped by BIL* *kV*		
	20-45	46-95	> 96		20-45	46-95	> 96
15	242	182	61	15	4	–	–
25	42	182	61	30	7	–	–
37.5	61	42	18	45	7	–	–
50	61	42	18	75	10	2	–
75	30	18	12	112.5	34	4	–
100	30	18	12	150	30	5	–
167	12	18	6	225	36	12	–
250	7	8	2	300	91	30	25
333	12	18	6	500	121	85	74
500	12	18	6	750	121	121	75
667	–	–	–	1,000	61	242	194
833	–	–	–	1,500	–	363	244
–	–	–	–	2,000	–	605	280
–		182	61	2,500	–	605	394
Total Units	**709**	**546**	**202**	**Total Units**	**522**	**2,074**	**1,286**
Total MVA	**23**	**23**	**9**	**Total MVA**	**257**	**3,655**	**2,206**

Source HVOLT Inc.
* BIL = basic impulse insulation level.

The shipments model incorporates two major assumptions. The first is that the relative market shares of the various transformer equipment classes and size categories are constant over time. In actuality, the average size of transformers probably increases gradually as the electricity demand per customer increases, but DOE has insufficient data to characterize such size trends.

The second assumption concerns the use of the BEA quantity index data. The BEA index data include shipments of transformers other than those covered by this rulemaking. The use of the BEA's SIC code 3612 (NAICS code 335311) quantity index to estimate shipments assumes that the quantity market share of distribution transformers relative to all NAICS code 335311 transformers is relatively constant for 1977–2009. DOE made this assumption because disaggregated quantity index data were not available.

9.3.2 Shipments Backcast

The shipments backcast is the estimate of previous aggregate transformer shipments based on limited historical data. The backcast of transformer shipments is a key element in estimating the age distributions of future in-service transformer stock. The shipments backcast begins with the estimate of transformer shipments in 2001,[1] then uses BEA's NAICS code 335311 quantity index to estimate total shipments for 1977–2008.[4] Specifically, DOE used the following equation to backcast shipments from 2008 to 1977.

$$TotShip(y) = TotShip(2001) \times BEA(y)/BEA(2001).$$

Where:

TotShip(y)	=	the total capacity of transformer shipments estimated for year *y* where $1977 \leq y < 2008$ (MVA);
TotShip(2001)	=	the total transformer capacity shipped (MVA) based on the shipments estimate (MVA); and
BEA(y)	=	the BEA quantity index for year *y*.

Annual shipments of transformer capacity prior to 1977 are backcast to 1950 using annual growth of electricity consumption from Table 8.9 of the DOE Energy Information Administration (EIA)'s Annual Energy Review 2009*,* a proxy for growth of transformer sales during this period.[5] Using this method, the shipments for 1950–1977 are given by the following equation.

$$TotShip(y) = TotShip(1977) \times AllElec(y) \,/\, AllElec(1977).$$

Where:

TotShip(y)	=	the total capacity of shipments estimated for year *y* where $1950 \leq y < 1977$ (MVA); and
AllElec(y)	=	the national electricity consumption in year *y* (kWh) according to EIA's Annual Energy Outlook 2010 (*AEO2011*).[6]

9.3.3 Shipments Forecast

After constructing a shipments backcast and calibrating it with shipments data, DOE constructed a forecast of transformer shipments. This forecast provided the input necessary to develop equipment cost and the stock accounting of in-service transformers. DOE constructed a simplified forecast of transformer shipments for the base-case scenario based on the assumption that long-term growth in electricity consumption will drive transformer shipments. The detailed dynamics of transformer shipments are highly complex. This complexity can be seen in the fluctuations in the quantity of transformers manufactured, as expressed by the BEA transformer quantity index. DOE examined the possibility of modeling the fluctuations in number of transformers shipped using a bottom-up model in which shipments are triggered by retirements and additions of new capacity, but found insufficient data to calibrate model parameters within an acceptable margin of error. Hence, in the constructing the shipments forecast DOE decoupled the overall shipments and retirements and used a retirement function to maintain the age distribution of the in-service transformer stock.

DOE constructed the transformer shipments forecast assuming that growth in transformer shipments is equal to forecasted growth in electricity consumption, as given by the *AEO2011* forecast through 2035.[7] For 2036–2045, DOE extrapolated the *AEO 2011* forecast, using its growth rate of electricity consumption between 2025 and 2035. Specifically, DOE used the following equation for the shipments forecast.

$$TotShip(y) = TotShip(2009) \times AllElec(y) \,/\, AllElec(2001).$$

Where:

$TotShip(y)$ = the total capacity of shipments estimated for year y where $2011 < y \leq 2045$ (MVA); and
$AllElec(y)$ = the national electricity consumption for year y (kWh) forecasted by *AEO2011* (or by an extrapolation of *AEO2011* data).

The following section describes how DOE adjusted its base-case forecast to account for price increases arising from each trial *standard*.

9.3.4 Long-Term Price Elasticity

Long-term price elasticity is a measure of how sensitive transformer shipments are to potential increases in price. Elasticity is defined as the percentage change in quantity purchased divided by the percentage change in price (or some other factor that influences purchase behavior). The basic formula DOE used to determine price elasticity is:

$$e = (dQ/Q) / (dP/P).$$

Where:

dQ/Q = a small percentage change in quantity purchased (Q), and
dP/P = a small percentage change in price.

If the elasticity is constant, then the quantity purchased can be written in terms of the price, a reference price, a reference quantity, and the elasticity. Specifically, the following equation holds true when the elasticity is constant.

$$Q(P) = Q0 \times (P/P0)\ e.$$

Where:

$Q(P)$ = the quantity purchased as a function of price,
Q_0 = a reference quantity at a reference price P_0, and
e = the elasticity, which is almost always negative or zero (i.e., non-positive) with respect to price.

For the shipments forecast, the reference price and the reference quantity are the price and quantity from the base-case scenario. DOE used price elasticity to adjust forecasts of base-case shipments for potential price increases due to a standard. A change in price due to a standard has an impact on the quantity purchased, $Q(P)$, as described by the above equation.

To model the purchase decisions made by utilities and other customers, DOE constructed a model that employs a standard econometric logit equation, such as those used for general applications of market response to costs and perceived utility. To determine the parameters of the logit equation for liquid-immersed transformers, DOE fitted the model to transformer purchase data from U.S. Federal Energy Regulatory Commission Form No. 15. This procedure resulted in a value of -0.04 for price elasticity. DOE assigned -0.04 as the medium scenario for liquid-immersed transformers and incremented the elasticity to -0.2 to implement a high sensitivity to price change. The low scenario assumes zero elasticity, or no impact on purchase decisions from a price change. No historical purchase data were available for dry-type transformers. Because dry-type units are used primarily in commercial and industrial applications, as are unitary air conditioners, DOE used sales and price data for air conditioners to estimate price elasticity for dry-type transformers. DOE fitted the model to the Air-Conditioning and Refrigeration Institute's sales data and the real Producer Price Index (PPI) of unitary air conditioners.[8] The resulting value of elasticity was -0.02. DOE assigned -0.02 as the medium scenario for dry-type transformers and incremented the elasticity to -0.2 to implement a high sensitivity to price change. The low scenario assumes zero elasticity, or no impact on purchase decisions from a price change.

9.3.5 Market Shares of Liquid-Immersed and Dry-Type Transformers

The shipments forecast and backcast described above provided an aggregate estimate of the total capacity of transformers shipped from 1950 to 2045. To disaggregate the total capacity into the capacity for the two types of transformers, DOE assigned liquid-immersed and dry-type *market shares by capacity. To distinguish between the various equipment classes and size* categories within each equipment class, DOE used estimates of market shares from 2001. DOE used trends in electricity consumption from EIA's retail sales data to estimate market share trends for the two types of transformers.[5] Based on the assumption that transformer sales over the long term track electricity sales for the sectors served by those transformers, DOE derived the following market share model.

$$\begin{gathered} LiqShip(y) = CL \times AllElec(y), \\ \text{where } CL = LiqShip(2001) / AllElec(2001)\ \forall\, y \leq 2008 \text{ and} \\ CL = LiqShip(2009) / AllElec(2009)\ \forall\, y \geq 2009. \end{gathered}$$

$$\begin{gathered} DryShip(y) = CD \times CIElec(y), \\ \text{where } CD = DryShip(2001) / CIElec(2001) \text{ for all } y \leq 2008 \text{ and} \\ CD = DryShip(2009) / CIElec(2009) \text{ for all } y \geq 2009. \end{gathered}$$

$$DryMS(y) = CD \times CIElec(y) / (CL \times AllElec(y) + CD \times CIElec(y)).$$

$$LiqMS(y) = 1 - DryMS(y).$$

Where:

CL	=	the constant of proportionality between the electricity consumption and the sales of liquid-immersed transformers in 2001,
CD	=	the constant of proportionality between the electricity consumption and the sales of dry-type transformers in 2001,

LiqShip(2001)	=	the capacity of liquid-immersed transformers shipped in 2001 (MVA),
DryShip(2001)	=	the capacity of dry-type transformers shipped in 2001 (MVA),
LiqShip(2009)	=	the capacity of liquid-immersed transformers shipped in 2009 (MVA),
DryShip(2009)	=	the capacity of dry-type transformers shipped in 2009 (MVA),
AllElec(y)	=	the total consumption of electricity in year y (kWh),
CIElec(y)	=	the consumption of electricity by the commercial and industrial sectors in year y (kWh),
LiqMS(y)	=	the capacity market share of liquid-immersed transformers in year y (%), and
DryMS(y)	=	the capacity market share of dry-type transformers in year y (%).

The dynamics that determine market shares of liquid-immersed and dry-type transformers likely are complicated, but DOE believes the process and equation described above represent the best way to capture long-term average trends in market share, given the lack of long-term, detailed market share data. The key assumption behind the market share equations is that market shares by transformer capacity follow the relative electricity consumption of the end users of the electricity that passes through the transformers. DOE also assumed that the relative market shares of various kVA ratings and equipment classes within each transformer type (i.e., liquid-immersed or dry-type) is constant over time. Given a lack of detailed, long-term market share data, an alternative assumption regarding market shares by kVA rating and equipment class may not be supportable.

After fully specifying the shipments backcast, forecast, elasticity, and market shares, DOE had completely specified the characteristics of transformer shipments. The next step was to provide an accounting of in-service transformer stocks, as described in the following section.

9.3.6 Stock Accounting

DOE's stock accounting used transformer shipments, a retirement function, and initial in-service transformer stock as inputs to develop an estimate of the age distribution of in-service transformer stocks for all years. The age distribution of in-service transformer stocks is a key input to calculations of both the NES and NPV, because the operating costs for any year depend on the age distribution. The transformer age distribution affects operating costs because, under a trial standard scenario that produces increasing efficiency over time, the operating costs of older, less efficient transformers are higher than those of newer, more efficient transformers .

DOE calculated the total in-service stock of distribution transformers by integrating historical shipments starting from 1950. As transformers are added to the in-service stock, some older ones retire and exit the stock. DOE developed a series of equations that define the dynamics and accounting of in-service transformer stocks. For new units, the equation is:

$$Stock(y, age = 1) = Ship(y - 1).$$

Where:

Stock (y, age)	=	the population of in-service transformers of a particular age (MVA),
y	=	the year for which the in-service stock is being estimated, and
Ship (y)	=	the number of transformers purchased in a particular year (MVA).

The above equation indicates that the number of one-year-old units is equal simply to the number of new transformer units purchased the previous year. Slightly more complicated equations account for the existing in-service stock of transformer units:

$$Stock(y+1, age+1) = Stock(y, age) \times [1 - Prob_{Retire}(age)].$$

The above equation says that, as time passes, only a fraction of the in-service stock exists the following year. As the year is incremented from y to $y + 1$, the age is also incremented from *age* to *age + 1*. Also, as time passes, a fraction of the in-service stock is removed. That fraction is determined by a retirement probability function, *ProbRetire(age)*, which is described in the following section.

9.3.7 Retirement Function

The accounting of in-service transformer stock requires specifying a retirement probability function for distribution transformers. DOE derived this probability function from a modified version of a transformer reliability function. The reliability function for determining the lifetime of a transformer is a Weibull distribution adapted from an earlier study by Oak Ridge National Laboratory (ORNL) for DOE:[9]

$$r(age) = exp\left[-\left(\frac{age}{d}\right)^{d}\right]((1 - constfail)^{age} \times (1 - constfail)^{age-15}).$$

Where:

r(age)	=	the reliability of a transformer of a certain age, where reliability is defined as the probability that the transformer will last to that particular age;
d and e	=	parameters used for fitting the reliability data;
constfail	=	a constant failure rate of 0.5 percent per year;[a] and
corrfail	=	a corrosive failure rate of 0.5 percent per year at age 15 and above.

DOE adjusted the parameters of the Weibull distribution to maintain an average lifetime of 32 years. It adapted the failure rates and the lifetime from ORNL.[7]

DOE converted the reliability function into an annual retirement probability function by dividing the incremental reliability at a given age by the fraction of transformers that last to that age:

---

[a] Constant failure could be due to lightning or other random events.

$$Prob_{Retire}(age) = \frac{[r(age-1) - r(age)]}{r(age)}$$

.

Where:

$Prob_{Retire}\ (age)$ = the probability that a transformer of a particular age will be retired.

Figure 9.3.1 shows the retirement rate for distribution transformers.

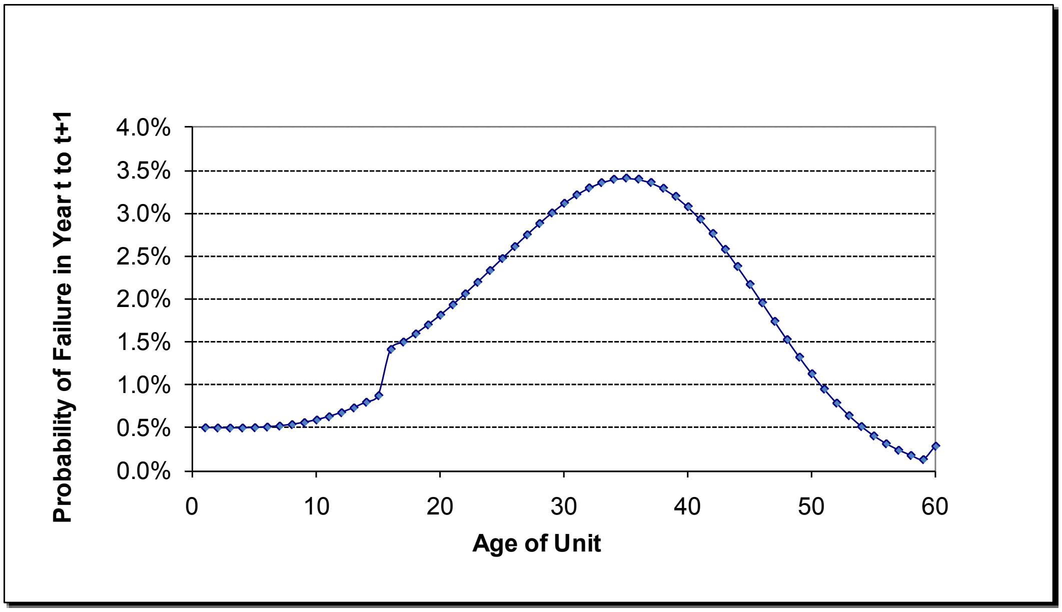

Figure 9.3.1 Percent of Original-Stock Retiring

DOE considered the possibility that more efficient transformers may operate at lower temperatures, which could alter their retirement function. After reviewing the engineering data, DOE found that more efficient transformers made with an amorphous core material demonstrate a significant drop in operating temperatures. Theoretically, lower operating temperatures should lower the degradation rate of electrical insulation in the transformer and result in fewer failures over time. Amorphous core technology is relatively recent (within the last couple of decades), however, and the technology can require larger, bulkier transformers, features that may contribute to more frequent replacements over the long term. The larger size and weight, for example, can lead to increased failures during storms or increased replacements because of size or space constraints. DOE did not have enough information to determine whether such transformers would have longer or shorter lifetimes relative to baseline transformers and therefore estimated that the transformer lifetime function should be independent of transformer efficiency.

9.3.8 Refurbishments and Rewinds

Transformers that are not retired can be refurbished and returned to the stock. Minor refurbishments may include replacing connectors, bushings, or the oil. Major refurbishments may include rewinding the transformer, an operation often performed by a specialized firm. ORNL reported annual refurbished capacity, including rewound units, to be approximately one percent of the in-service transformer capacity.[7] DOE carried out further research, including discussions with owners of transformers, to finalize the estimate of annual refurbishments. The findings were inconclusive. Currently, major refurbishment appears to represent a small fraction of the distribution transformer market; however, that share could increase in response to the imposition of an energy efficiency standard. Transformer users expressed hesitancy regarding widespread adoption of rewound transformers. Not finding a consensus regarding transformer refurbishment, DOE did not include major refurbishments in the current analysis. Minor refurbishment is widespread and already is captured in the retirement function.

After DOE specified the retirement probability function, the remaining input to the stock-accounting equation was the initial in-service stock of transformers, as described in the following sections.

9.3.9 Initial Stock

DOE began applying the stock-accounting model for1950, the first year for which electricity consumption data were available.[5]
For simplicity, DOE set the in-service transformer stock in the first year at zero.[a] This number does not affect the analysis because most of the transformer stock from 1950 would not be in service after 2001.

9.3.10 Effective Date of Standard

A key output of the shipments model is the in-service stock of transformers that may be affected by a standard. To calculate this affected stock, the effective date of the standard must be defined. For this analysis DOE assumed that any new energy efficiency standard for distribution transformers would become effective in 2016. The exact effective date of the standard is January 1, 2016, so all distribution transformers manufactured or imported starting on the first day of 2016 are affected by the standard.

9.3.11 Affected Stock

The affected stock is an output of the shipments model and a key input to the calculations of NES and NPV. The affected stock consists of that percentage of the in-service transformer stock that may be impacted by a standard. It therefore consists of those in-service transformers that are purchased in or after the year the standard has taken effect, as described by the following equation.

[a] Note that transformer stocks in 1950 were small compared to those in 2001.

$$AffStock(y) = Ship(y) + \sum_{age=1}^{y-StdYear} Stock(age).$$

Where:

AffStock(y)	=	the stock of transformers of all vintages that are operational in year *y* (MVA),
Ship(y)	=	the shipments in year *y* (MVA), and
age	=	the age of the transformer (years).

Section 9.4 summarizes results of DOE's shipments analysis. After DOE specified the shipments, in-service stocks, and affected stocks of transformers, it was able to calculate the NES and NPV. Those calculations are described in chapter 10.

9.4 RESULTS

The primary output of the shipments model is the total capacity of distribution transformers shipped annually from 2016 through 2045. Total shipments depend on transformer lifetime, the price elasticity of transformer purchases, and growth in new electricity demand. Total shipments for all draft trial standard levels for liquid-immersed and dry-type distribution transformers throughout the forecast period are shown in Table 9.4.1.

Table 9.4.1 Cumulative Shipments of Transformers by Trial Standard Level, 2016–2045 *Billion kVA*

	Trial Standard Level							
	Base case	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Liquid-Immersed	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Low-Voltage Dry-Type	0.62	0.62	0.62	0.62	0.61	0.61	0.61	
Medium-Voltage Dry-Type	0.22	0.22	0.22	0.22	0.22	0.22		

The size of the potential standards-induced change in shipments is influenced greatly by the increase in equipment price due to standards. Given a large price increase, the volume of shipments will decrease almost proportionally to the price increase, but because the price elasticity of transformers is less than one, price increases will result in increased gross sales dollar volume to the transformer manufacturer. The net financial impact of these opposing effects is examined in the MIA, chapter 12 of the notice of proposed rulemaking.

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CHAPTER 10. NATIONAL IMPACT ANALYSIS

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CHAPTER 10. NATIONAL IMPACT ANALYSIS

10.1 INTRODUCTION

The Energy Policy and Conservation Act (EPCA) of 1975, as amended, states that any new or amended energy efficiency standard must be selected to achieve the maximum improvement in energy efficiency that is both technologically feasible and economically justified. In determining whether a standard is economically justified, the U.S. Department of Energy (DOE) must determine whether the benefits of the potential standard outweigh its burdens. Key factors in this decision are the total projected amount of energy savings likely to result directly from the imposition of the standard, and the savings in operating costs throughout the life of the covered equipment compared to any increase in its price, or in its initial charges or maintenance, that are likely to result from promulgation of the standard.

To satisfy this EPCA requirement and to more fully understand the overall impact of potential efficiency standards for distribution transformers, DOE conducted a national impact analysis (NIA). The NIA assessed future national energy savings (NES) from energy conservation standards for transformers and the national economic impact using the net present value (NPV). This chapter describes the method DOE used to estimate the national impacts of draft trial standard levels for medium-voltage liquid-immersed and low- and medium-voltage dry-type distribution transformers. The analyses that preceded the shipments analysis in chapter 9 (e.g., the engineering analysis [chapter 5] and the life-cycle cost analysis [chapter 8] examined transformers by design line, accounting for the 14 distinct design options found in transformers. For the NIA, DOE must examine impacts as they relate to equipment classes, because the final standards will apply to equipment classes, not design lines. DOE evaluated the following impacts: (1) NES attributable to each potential standard, (2) monetary value of the NES to purchasers of the considered equipment, (3) increased total installed cost of the equipment because of standards, and (4) NPV of energy savings (the difference between the operating cost savings and increased total installed cost).

To conduct its NIA, DOE determined both the NES and NPV for each draft trial standard level being considered for distribution transformers. DOE performed all calculations for each considered equipment class using a Microsoft Excel spreadsheet model. The national impact spreadsheet is available as an Excel file on the DOE website: www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html.

The spreadsheets combine the calculations for determining the NES and NPV for each considered equipment class with input from the appropriate shipments model that DOE used to forecast future purchases of transformers. Chapter 9 provides a detailed description of the shipments model, including customers' sensitivities to total installed cost, operating cost, and income, and how DOE captured those sensitivities within the model. The NES and NPV together constitute the NIA model. Additional details, along with instructions for using the NIA spreadsheet, are provided in appendix 10A of this technical support document.

Figure 10.1.1 presents a flow diagram of the model and spreadsheets used to perform the NIA (NES and NPV) for distribution transformers. In the diagram, arrows show the direction that information flows when the calculation is performed. The process begins with inputs (shown as parallelograms). As information flows from the inputs, it may be integrated into intermediate results (shown as rectangles) or, via integrating sums or differences (shown as circles), into major outputs (shown as boxes having wavy bottom edges).

The NIA calculation starts with the shipments model (chapter 9), which is shaded in the flow diagram. For transformers, the model integrated the inputs of estimates of 2001 and 2009 shipments from DOE's contractor,[1,2] the U.S. Bureau of Economic Analysis (BEA) transformer quantity index,[3] electricity market shares from DOE's Energy Information Administration (EIA),[4,5] and equipment price estimates from DOE's life-cycle cost (LCC) analysis. The model produced both a backcast and a forecast of total shipments. DOE used the total shipments and a retirement function to produce an accounting of in-service transformers (stocks), enabling DOE to estimate the stock that would be affected by draft trial standard levels and transformer retirements.

DOE used a scaling factor (described in section 10.2.2.1) to estimate the national impacts of new standards for all the equipment classes considered in this rulemaking. The scaling factor is applied to the equipment cost and annual energy consumption of each representative transformer size so they can describe all sizes within that equipment class.

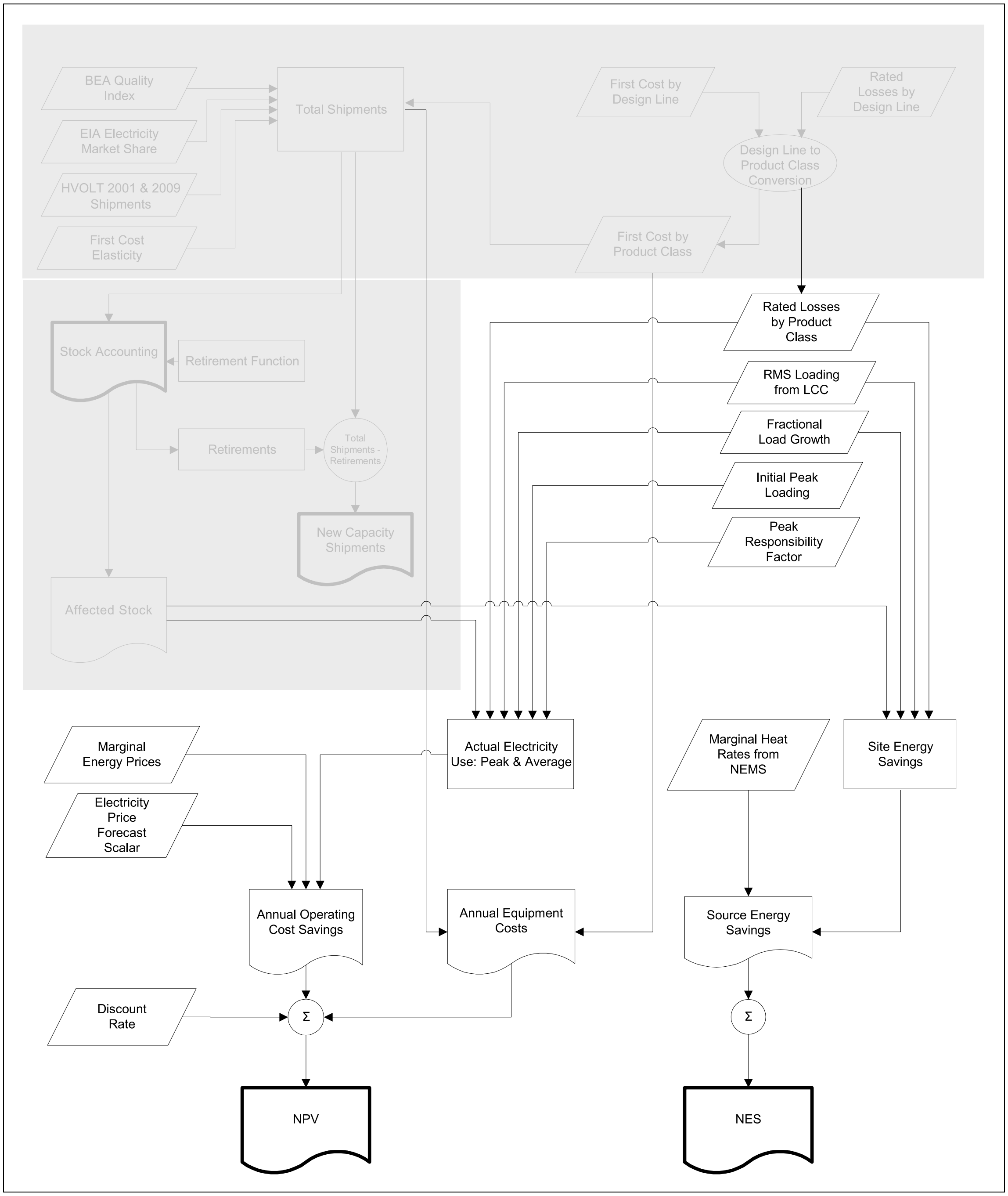

Figure 10.1.1 Flowchart of National Impact Analysis

Following the calculation of shipments, the calculations of NES and NPV begin. For both calculations, key inputs from the LCC analysis are the average rated no-load and load losses and the cost of transformers, including installation. DOE adjusted the losses and equipment costs for transformer size and type to convert the applicability of the data from representative design lines to average equipment classes. Additional inputs on average and peak losses—including root mean square (RMS) loading, peak loading, and peak responsibility factor—enabled DOE to convert rated losses into actual losses. At this point, the information flow for the NES and NPV calculation splits into two paths.

On one path, the NES calculation sums the kilowatt-hours of energy consumed by the affected stock, taking the difference between the base-case and standards scenario to calculate site energy savings. DOE converted site energy savings to energy savings at the source (i.e., at the power plant), using average heat rates for base load and peak load generation from DOE's National Energy Modeling System (NEMS).[6] The average heat rates from NEMS include transmission and distribution losses. Summing the annual energy savings for the forecast period, which extends from 2016 through 2045, provides the final NES result.

On the other path, the NPV calculation starts with marginal price inputs from the LCC analysis for both energy and capacity costs and for both load and no-load losses. The marginal prices, combined with the actual peak and average losses, provide estimates of operating costs. Meanwhile, the adjusted cost of installed equipment times the annual shipments provides the estimate of the total annual equipment costs. DOE calculated three differences to assess the net impact of each draft trial standard level (TSL). The first difference was between equipment costs in each TSL scenario and the base case to obtain the net increase in equipment cost attributable to the TSL. The second difference was between operating costs under the base-case scenario and each TSL to obtain the net operating cost savings from the TSL. The third difference was between the net operating cost savings and the net increase in equipment cost, which provides the net expense or savings for each year. To obtain the NPV impact of a TSL, DOE discounted the net expenses or savings to 2010$ and summed them for 2016–2104[a] for transformers purchased during 2016–2045.

The two models that comprise the NIA are described below—the NES model in section 10.2, and the NPV model in section 10.3. Each description begins with a summary of the model, followed by an overview of how DOE performed that model's calculations. Then model inputs are summarized. The final subsections of the two sections describe each of the major inputs and computational steps in detail and with equations when appropriate. After the technical descriptions of the models, this chapter presents the results of the NIA calculations.

10.2 NATIONAL ENERGY SAVINGS

DOE developed the national energy savings (NES) model to estimate the total NES using results from the shipments model combined with information from the LCC on energy savings. The savings shown in the NES reflect decreased energy losses resulting from the installation of new, more efficient transformer units nationwide, in comparison to a base case in which there are no national standards. Positive values of NES correspond to net energy savings, specifically a decrease in energy consumption after implementation of a standard, in comparison to the energy consumption in the base-case scenario.

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[a] The analysis period for NPV is based on the cumulative operating cost savings of the last unit shipped (2045 + maximum transformer life -1).

10.2.1 Overview

DOE calculated the cumulative incremental energy savings from each potential transformer efficiency standard relative to a base-case scenario of the current efficiency standard. It calculated NES, in units of quads, throughout the forecast period for standards that it assumed will be effective in 2016. The NES calculation started with estimates of transformer shipments and stocks (in-service transformers), which are outputs of the shipments model (chapter 9). DOE then obtained estimates of transformer energy losses from the LCC analysis (chapter 8), and calculated the total energy use by the stock of transformers for each year for both a base case and a standards case. In each standards case, as more efficient transformers replace less efficient ones that retire from service, the energy per unit capacity used by the stock of transformers gradually decreases relative to the base case. DOE used a site-to-source conversion factor to convert the amount of energy used by the transformers into the amount of energy consumed at the source of electricity generation (the source energy). The site-to-source conversion factor accounts for transmission, distribution, and generation losses. For each year analyzed, the difference in source energy use between the base case and the standards scenario is the annual energy savings. DOE summed the annual energy savings from 2016 through 2045 to calculate the total NES for the forecast period.

In calculating the NES, DOE did not assume any trends in transformer name-plate efficiency besides the incremental improvement indicated by the LCC calculation. In examining proprietary shipments data provided by the transformer industry, DOE found that the data revealed no conclusive trends in improved efficiency. Deciding that future efficiency trends generally are indeterminate, DOE chose to use fixed baseline efficiency. DOE also assumed that the efficiency of transformers does not degrade over time. Therefore the annual energy savings can be described in terms of an affected stock, as described in section 9.3.11 of the shipments chapter. Annual energy savings therefore are described by the following equation.

$$AES(y) = (UECBase - UECStd) \times Aff\_Stock(y)$$

Where:

$AES(y)$	=	the annual energy savings in year y,
$UECBase$	=	the site unit energy consumption for the base case,
$UECStd$	=	the site unit energy consumption for the standards case, and
$Aff\_Stock(y)$	=	the stock of transformers of all vintages that are operational in year y.

Given the annual energy savings, the cumulative NES can then be calculated as a simple sum.

$$NES = \sum_{y=Std_{year}}^{2045} SiteToSource(y) \times AEC(y)$$

Where:

Std_{year}	=	the year standards come into effect,
SiteToSource(y)	=	the site-to-source conversion factor in year *y*, and
AEC	=	the annual energy consumption.

After the shipments model provides the estimate of affected stock, the NES calculates *UECBase* and *UECStd* using the output from the LCC analysis and including the site-to-source conversion factor. The following section summarizes the inputs necessary for the NES calculation and then describes each input individually.

10.2.2 Inputs

Inputs to the NES model fall into three broad categories: (1) those that help convert the data from the LCC into data relevant to the equipment classes and transformer size distributions used in the NES; (2) those that help calculate the unit energy consumption; and (3) the site-to-source conversion factor, which enables the calculation of source energy consumption from site energy use. The specific NES model inputs are:

1. size scaling of losses and costs,
2. mapping of LCC design line data to equipment classes,
3. root mean square loading,
4. load growth,
5. affected stock,
6. effective date of standard,
7. unit energy consumption, and
8. electricity site-to-source conversion.

Each input is described further below.

10.2.2.1 Size Scaling of Losses and Costs

Transformers are produced over a broad range of capacities, only a few of which are modeled explicitly in this analysis. The modeled designs are referred to as representative units. Any given equipment type includes 2-4 representative units at different capacity, or kVA values. DOE used a scaling relationship, or equation, to project the economic results from a given transformer design line to similar transformers of different sizes. This relationship is a key element in adjusting losses and costs from a representative transformer in the LCC to the distribution of transformer sizes incorporated in the calculation of NES and subject to potential standards. The Department uses the *0.75 scaling rule* to scale the cost and efficiency results for the modeled kVA values to the full capacity range for each type, the 0.75 scaling rule is discussed in greater detail in chapter 5. This rule assumes that both the physical and cost characteristics are determined by the quantity of material required to build the transformer, and is approximately true. In practice, if the kVA-range over which cost and efficiency data are to be scaled is large, the 0.75 rule is less accurate. This manifests as kinks or angles in the curve of efficiency as a function of capacity for a given equipment type.

The Department has implemented a correction to the 0.75 scaling rule to produce smoother curves of efficiency vs. capacity. This correction adjusts the value of the exponent (the 0.75 of the scaling rule) so that the curve extrapolates correctly between any two representative units. Mathematically, the efficiency of a transformer is equal to the ratio:

$$Eff = \frac{Load}{(Load + Losses)}$$

Where:

Eff	=	transformer efficiency
Load	=	the load on the transformer
Losses	=	the transformer's combined no-load and load losses.

Load is proportional to capacity kVA, and if the 0.75 scaling rule is valid, losses are proportional to $(\text{kVA})^{0.75}$. This expression can thus be written as,

$$Eff = \frac{1}{(1 + Constant \times (kVA)^{-0.25})}$$

Defining the loss function as

$$Losses = \frac{1}{Eff - 1},$$

$$Losses = Constant \times (kVA)^{-0.25}$$

For two representative units labeled 1 and 2,

$$Log\left(\frac{Losses_1}{Losses_2}\right) = -0.25\, Log\left(\frac{kVA_1}{kVA_2}\right)$$

The validity of the 0.75 scaling rule can thus be tested by evaluating the ratio,

$$x = \frac{-Log\left({Losses_1}/{Losses_2}\right)}{Log\left({kVA_1}/{kVA_2}\right)}$$

The Department uses the exponent *x* calculated through the above equation, instead of the value -0.25 implied by the scaling rule, to interpolate the efficiency between any two representative units. The Department uses the unmodified scaling rule to extrapolate efficiency values to capacities below the minimum representative unit, or above the maximum representative unit.

The Department calculated an adjustment factor using the exponent x to account for the fact that the representative design line unit used in the engineering analysis is not the "average" size for the set of transformers that the design line represents. This adjustment factor is given by the following equation.

$$AdjFactor = \frac{\sum_i [Ship_i \times Cap_i{}^{1+x}]}{(Cap_{DL}{}^{1+x} \times \sum_i Ship_i)}$$

Where:

AdjFactor	=	the adjustment factor that, when multiplied by the design line losses or costs, gives the shipment-weighted losses or costs per transformer;
$Ship_i$	=	the shipments in the i-th size category;
Cap_i	=	the rated capacity of the transformers in the i-th size category; and
Cap_{DL}	=	the rated capacity of the representative unit of the design line.

DOE also used the shipment-weighted average size of transformers represented by a particular design line to calculate the average loss per capacity ($AvgLossPerCap_{DL}$), as described by:

$$AvgLossPerCap_{DL} = LossPerCap_{DL} \times AdjFactor \times \frac{Cap_{DL}}{Cap_{avg}}$$

Where:

$LossPerCap_{DL}$	=	the loss, or cost per unit capacity, for the design line unit from the LCC analysis, and
Cap_{avg}	=	the shipment-weighted average size of transformers represented by a particular design line.

After the losses and costs from the LCC were adjusted to represent the correct size distribution, they needed a further adjustment to represent the appropriate equipment classes, as described in the following section.

10.2.2.2 Mapping Design Line Data to Equipment Classes

The calculations of NES and NPV use the LCC calculations (chapter 8) as the source of most input data. DOE performed the LCC calculations by design line, whereas any standard will be promulgated by equipment class. As a first step, therefore, the NES calculation aggregates the

LCC design line data into equipment classes. DOE used this aggregation method to prepare for estimating economic impacts by equipment class.

To represent the range of designs in some equipment classes, DOE often analyzed several design lines per equipment class. For example, equipment class 1 (single-phase, medium-voltage, liquid-immersed transformers) is represented by three design lines, and equipment class 2 (three-phase, medium-voltage, liquid-immersed transformers) is represented by two design lines. DOE did not specifically examine single-phase, medium-voltage, dry-type design lines. For single-phase equipment classes 5, 7, and 9, DOE used factors for the appropriate three-phase design lines divided by three. Table 10.2.1 presents the mapping of design line (DL) to equipment class (EC).

Table 10.2.1 Mapping of Design Line to Equipment Class

Equipment Class		**BIL*** ***kV***	**Capacity** ***kVA***	**Mapping**
1	Liquid-immersed, medium-voltage, single-phase	Any	10–833	DL1 + DL2 + DL3
2	Liquid-immersed, medium-voltage, three-phase	Any	15–2,500	DL4 + DL5
3	Dry-type, low-voltage, single-phase	≤ 10	15–333	DL6
4	Dry-type, low-voltage, three-phase	≤ 10	15–1,000	DL7+DL8
5	Dry-type, medium-voltage, single-phase	20–45	15–833	(DL9 + DL10)/3
6	Dry-type, medium-voltage, three-phase	20–45	15-2,500	DL9 + DL10
7	Dry-type, medium-voltage, single-phase	46–95	15–833	(DL11 + DL12)/3
8	Dry-type, medium-voltage, three-phase	46–95	15–2,500	DL11 + DL12
9	Dry-type, medium-voltage, single-phase	> 95	75–833	(DL13A + DL13B)/3
10	Dry-type, medium-voltage, three-phase	> 95	225–2,500	DL13A + DL13B

* BIL = basic impulse insulation level in kilovolts (kV).

To aggregate losses from more than one design line, DOE applied the average of shipments weighted by capacity of the per-kilovolt-ampere (kVA) transformer characteristics from the economic analysis of the design lines to the estimated capacity shipped for each equipment class. DOE's contractor[1,2] provided the capacity shipped for each design line (and each equipment class). The LCC analysis provided the economic results for each design line, and DOE used the scaling method described in section 10.2.2.1 to estimate the scaled cost and loss estimates for each size category represented by each design line. The following equation provides the average loss per unit capacity for an equipment class ($AvgLossPerCap_{EC}$) as derived from the average loss per unit capacity for a design line. The equation sums those design lines that constitute an equipment class.

$$AvgLossPerCap_{EC} = \frac{\sum_{DL}[AvgLossPerCap_{DL} \times MS_{DL}]}{\sum_{DL} MS_{DL}}.$$

Where:

$AvgLossPerCap_{DL}$	=	the average loss per unit capacity for the design line, and
MS_{DL}	=	the design line's market share by capacity.

The $AvgLossPerCap_{EC}$ represents the average loss per unit capacity of the transformer load. No further adjustment is needed for no-load losses. For load losses, however, the losses at rated load must be converted to losses at actual loading. Root mean square (RMS) loading is a key factor used in estimating load losses at actual loading. The following section describes the RMS loading input to the NES.

10.2.2.3 Mapping Draft Efficiency Level to Draft Trial Standard Level

The Department conducted the LCC analysis for up to seven energy efficiency levels (EL) for each representative unit in the 14 design lines. The Department selected the ELs for each design line by applying a set of economic and design criteria to intermediate LCC analyses as discussed in chapter 5, resulting in unique sets of EL efficiencies for each design line. It mapped these LCC analysis results to draft trial standard levels (TSLs) for the 10 product classes.

For liquid-immersed distribution transformers the efficiency levels in each TSL can be characterized as follows: TSL 1 represents an increase in efficiency where a diversity of electrical steels are cost-competitive and economically feasible for all design lines; TSL 2 represents EL1 for all design lines; TSL 3 represents the maximum efficiency level achievable with M3 core steel; TSL 4 represents the maximum NPV with 7 percent discounting; TSL 5 represents EL 3 for all design lines; TSL 6 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 7 represents the maximum technologically feasible level (max tech).

For low-voltage, dry-type distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents the maximum efficiency level achievable with M6 core steel; TSL 2 represents NEMA premium levels; TSL 3 represents the maximum EL achievable using butt-lap miter core manufacturing for single-phase distribution transformers, and full miter core manufacturing for three-phase distribution transformers; TSL 4 represents the maximum NPV with 7 percent discounting; TSL 5 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 6 represents the maximum technologically feasible level (max tech).

For medium-voltage, dry-type distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents EL1 for all design lines; TSL 2 represents an increase in efficiency where a diversity of electrical steels are cost-competitive and economically feasible for all design lines; TSL 3 represents the maximum NPV with 7 percent discounting; TSL 4 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 5 represents the maximum technologically feasible level (max tech).

Table 10.2.2 Mapping of Draft Efficiency Levels to Draft Trial Standard Levels for Liquid-Immersed Transformers

Design Line		TSL1	TSL2	TSL3	TSL4	TSL5	TSL6	TSL7
1	Liquid-Immersed, 50kVA, single-phase	EL 1	EL 1	EL 1	EL 2	EL 3	EL 4	EL 7
2	Liquid-Immersed, 25kVA, single-phase	Base	EL 1	EL 1	EL 2	EL 3	EL 4	EL 7
3	Liquid-Immersed, 500kVA, single-phase	EL 1	EL 1	EL 2	EL 4	EL 3	EL 5	EL 7
4	Liquid-Immersed, 150kVA, three-phase	EL 1	EL 1	EL 1	EL 2	EL 3	EL 4	EL 7
5	Liquid-Immersed, 1500kVA, three-phase	EL 1	EL 1	EL 2	EL 4	EL 3	EL 5	EL 7

Table 10.2.3 Mapping of Draft Efficiency Levels to Draft Trial Standard Levels for Low-Voltage Dry-Type Transformers

Design Line		TSL1	TSL2*	TSL3	TSL4	TSL5	TSL6
6	LVDT, 25kVA, single-phase	Base	EL 3	EL 4	EL 6	EL 6	EL 7
7	LVDT, 75kVA, three-phase	EL 2	EL 3	EL 4	EL 6	EL 6	EL 7
8	LVDT, 300kVA, three-phase	EL 2	EL 2	EL 4	EL 6	EL 7	EL 7

*NEMA Premium

Table 10.2.4 Mapping of Draft Efficiency Levels to Draft Trial Standard Levels for Medium-Voltage Dry-Type Transformers

Design Line		TSL1	TSL2	TSL3	TSL4	TSL5
9	MVDT, 300kVA, three-phase, 45kV BIL	EL 1	EL 1	EL 2	EL 2	EL 7
10	MVDT, 1500kVA, three-phase, 45kV BIL	EL 1	EL 2	EL 2	EL 2	EL 7
11	MVDT, 300kVA, three-phase, 95kV BIL	EL 1	EL 1	EL 4	EL 4	EL 7
12	MVDT, 1500kVA, three-phase, 95kV BIL	EL 1	EL 2	EL 4	EL 4	EL 7
13A	MVDT, 300kVA, three-phase, 125kV BIL	EL 1	EL 1	EL 2	EL 4	EL 6
13B	MVDT, 2000kVA, three-phase, 125kV BIL	EL 1	EL 2	EL 2	EL 2	EL 5

10.2.2.4 Root Mean Square Load

Energy losses in transformers follow the RMS load, not the arithmetic average load. DOE calculated the RMS load as the RMS of the transformer load divided by the transformer rated capacity, then multiplied by the power factor. (As explained in chapter 6, although DOE's analytical method can derive results for varying power factors, for the analysis presented here DOE set the power factor to a value of one.) DOE used the average national RMS load for each design line as calculated for the LCC analysis. Those values range from 22.1 percent to 41.2 percent for the various design lines.

10.2.2.5 Load Growth

The load growth is the fraction by which the load increases after a transformer is installed. DOE investigated load growth as a sensitivity. Load growth occurs when new equipment, new appliances, or additional activities increase the energy loads on the circuits served by distribution transformers. Load growth increases the load losses relative to those estimated to have occurred during the first year of installation.

DOE calculated the fractional load growth from an estimated rate that it used as an input to the LCC analysis. There is a maximum load growth, *LGRMax*, which DOE set at 50 percent for liquid-immersed transformers. The 50-percent value represents the approximate amount of growth in load that can occur without overloading the transformer beyond a reasonable point. When overloading occurs, DOE assumed that the transformer would be installed in a new location where the initial peak loading would be the same as when originally installed.[7] See Institute of Electrical and Electronics Engineers, Inc. (IEEE) Std C57.91-1995[8] for details on permissible overloading of mineral-oil-immersed transformers. Because IEEE does not report data on permissible overloading of dry-type units, DOE used the same values for both liquid-immersed and dry-type transformers. The age at which a transformer load switches back to initial peak load is given by the following equation.

$$age_{Max} = \frac{ln\,(1 + LGRMax)}{ln(1 + LGR)}.$$

Where:

age_{Max} = the maximum age of the transformer after which time the load switches back to initial peak load (years), and
LGR = the annual load growth rate (%).

Thus, the equation for the load growth as a function of the age of the transformer is:

$$LGrwth(age) = (1 - LGR)^{(age)} - 1$$

for age < age_{Max}, and

$$LGrwth(age) = (1 - LGR)^{(age - ageMax)} - 1$$

for age >= age_{Max}.

Where:

$LGrwth\ (age)$ = the fractional load growth, and
age = the age of the transformer (years).

DOE then used the load growth to adjust the estimate of RMS load for the affected stock. The mathematical equation for this adjustment is:

$$LAdjust(y) = \sqrt{\sum_{age=1}^{y-Std\_year} \frac{[Stock(y, age) \times (1 + LGrwth(age))^2]}{Aff\_Stock(y)}},$$

where *LAdjust(y)* is the load adjustment factor in year *y*. All other variables were defined for previous equations. DOE applied a load adjustment factor to RMS loading to incorporate load growth into the unit energy consumption, as described in section 10.2.2.7.

10.2.2.6 Affected Stock

The affected stock, an output of the shipments model (chapter 9), is a key input for the NES and NPV calculations. The affected stock represents that part of the transformer stock that would be impacted by a standard. It consists of those transformers purchased in or after the year the standard takes effect, as described by the following equation.

$$Aff_{Stock(y)} = Ship(y) + \sum_{age=1}^{y-Std_{year}} Stock(age).$$

Where:

Aff_Stock(y)	=	stock of affected transformers of all vintages that are operational in year *y*,
Ship(y)	=	shipment of new transformers in year *y*,
Std_year	=	year the standard becomes effective, and
Stock(age)	=	age in years of the stock of transformers.

10.2.2.7 Unit Energy Consumption

One of the final quantities DOE calculated to estimate the NES was the unit energy consumption for affected stock. The unit energy consumption multiplied by the capacity shipped and the site-to-source conversion factor equals the annual site energy consumption from which DOE derived total NES.

Annual unit energy consumption *(UEC(y))* for affected stock is the annual energy consumption per unit capacity for transformers shipped after the effective date of a standard. DOE calculated the losses per transformer as the sum of no-load losses plus load losses. It calculated the load losses as the rated load loss times the square of the RMS load, adjusted for load growth. Average energy consumed per unit capacity for affected stock varies from year to year because of load growth effects. The annual unit energy consumption for affected stock of distribution transformers is given by the following equation.

$$UEC(y) = E_{NL} + E_{LL} \times [RMS \times LAdjust(y)]^2.$$

Where:

E_{NL}	=	rated no-load losses per kVA capacity,
E_{LL}	=	rated load losses per kVA capacity,
RMS	=	root mean square, and
$LAdjust(y)$	=	load adjustment factor for year y.

After DOE defined the unit energy consumption for affected stock, only one more input was necessary to complete the NES calculation: the site-to-source conversion factor.

10.2.2.8 Site-to-Source Electricity Conversion

The site-to-source conversion factor for electricity is the factor by which site energy (in kilowatt-hours [kWh]) is multiplied to obtain primary (source) energy (in quadrillion British thermal units [quads]). Because the NES estimates the change in energy use of the resource (e.g., at the power plant), this conversion factor is necessary to account for losses in generation, transmission, and distribution. After calculating energy consumption at the site of use—the installed transformer—DOE multiplied the site energy consumption by the conversion factor to obtain primary energy consumption, expressed in quads. This conversion permitted comparison across (source) fuels by taking into account the heat content of various fuels and the efficiency of various energy conversion processes. The annual conversion factors are the United States averages for generating electricity for both peak and base loads. DOE used average heat rates corresponding to base load for no-load losses (or core losses), and average heat rates corresponding to peak load for load losses (or coil losses). It used different rates because load losses are higher during transformer peak loads, whereas no-load losses occur at all times. DOE developed conversion factors using a variant of the NEMS[5] called NEMS-BT.[b] Table 10.2.3 presents the average annual conversion factors DOE used.

[b] DOE/EIA approves use of the name NEMS to describe only an official version of the *moEL* without any modification to code or data. Because this analysis entailed some minor code modifications and the *moEL* is run under policy scenarios that are variations on DOE/EIA assumptions, the name NEMS-BT refers to the *moEL* as used here (BT is DOE's Building Technologies Program, under whose aegis this work was performed).

Table 10.2.5 Average Site-to-Source Conversion Factors for No-Load Losses and Load Losses

Year	No-Load Losses	Load Losses
2015	1.890	2.443
2016	1.888	2.446
2017	1.885	2.444
2018	1.883	2.443
2019	1.883	2.444
2020	1.886	2.446
2021	1.896	2.452
2022	1.900	2.450
2023	1.907	2.447
2024	1.915	2.448
2025	1.915	2.439
2026	1.916	2.425
2027	1.920	2.414
2028	1.921	2.395
2029	1.920	2.377
2030	1.919	2.355
2031	1.920	2.345
2032	1.920	2.330
2033	1.919	2.308
2034	1.920	2.294
2035	1.923	2.289
2036–2045	1.923	2.289

The conversion factors change over time to account for the changes in electricity-generating sources. The NES spreadsheet model includes the conversion factors for each year of the projection. DOE and stakeholders can examine the effects of alternative assumptions by revising the conversion factors in the NES spreadsheet.

The conversion of site energy savings to source energy savings and the summation of energy savings throughout the forecast period complete the calculations needed to estimate the NES. The next section (section 10.3) describes the technical details of the NPV calculation. Section 10.4 presents the NES and NPV results from the NIA spreadsheet model.

10.3 NET PRESENT VALUE

DOE used a national net present value (NPV) accounting component in the NIA spreadsheet to estimate the national financial impact on customers from the imposition of potential energy efficiency standards. DOE combined the output of the shipments model with energy savings and financial data from the LCC analysis to calculate an annual stream of costs and benefits resulting from draft trial standard levels (TSLs) for distribution transformers. It discounted this time series to 2010 and summed the result for 2016–2104 (the year the last unit shipped in 2045 retires from service), yielding the national NPV.

10.3.1 Overview

The NPV is the present value of the incremental economic impact of a TSL. Like the NES, the NPV calculation started with transformer shipments and stocks, estimates of which are outputs of the shipments model. DOE then obtained estimates of transformer first costs, losses, and average marginal electricity costs from the LCC analysis. It calculated the costs of transformer purchases and installation, then the corresponding operating costs for both a base case and a standards case, by applying marginal prices to the energy (both energy and electricity system capacity) used by the stock of transformers for each year. In the standards case, more expensive, but more efficient, transformers gradually replace less efficient units. Thus, the operating cost per unit capacity for the stock of transformers gradually decreases in the standards case relative to the base case, while equipment costs increase.

DOE used a simple national average discount factor to discount purchases, expenses, and operating costs for transformers. The discount factor converts a future expense or benefit to a present value. The difference in present value of all expenses and benefits between the base-case and standards scenario represents the impact on national NPV. DOE calculated the NPV impact for transformers purchased during the forecast period (between the effective date of the standard and 2104, inclusive). Mathematically, NPV is the value in the present of a time series of costs and savings, described by the equation:

$$NPV = PVS - PVC.$$

Where:

PVS = the present value of electricity savings, and
PVC = the present value of equipment costs including installation.

PVS and PVC are determined according to the following three equations.

$$PVS = \sum_{y=Std\_year}^{2104} \left[\frac{OC_{Base}}{Cap}(y) \times \frac{OC_{Std}}{Cap}(y)\right] \times Aff_{Stock(y)} \times Discount\ Factor(y).$$

Where:

$OC_{Base}/Cap(y)$ = operating cost in year y per unit capacity of transformer for the base case,
$Aff\_Stock(y)$ = stock of transformers of all vintages that are operational in year y,
y = the year (from effective date of the standard to the year when units purchased in 2045 retire [in 2104]), and

Discount Factor(y) = discount factor for year *y*, defined in the next equation.

$$Discount\ Factor(y) = \frac{1}{(1 + Discount\ Rate)^{(y - reference\ year)}}$$

Where:

reference year = 2016, and
discount rate = the discount rate, as described in section 10.3.2.7.

PVC is determined as follows.

$$PVC = \sum_{Std\_year}^{2104} \left[\frac{FC_{std}}{Cap}(y) - \frac{FC_{Base}}{Cap}(y)\right] \times Ship(y) \times DiscountFactor(y).$$

Where:

$FC_{Std}/Cap\ (y)$ = first cost of the transformer per unit of capacity for a EL *Std* in year *y* (first cost is described in section 10.3.2.1);
Std_year = the year the standard comes into effect, and
Ship(y) = shipments of transformers in year *y* for the standards case.

DOE calculated NPV using its projections of national expenditures for distribution transformers, including purchase price (equipment and installation price) and operating costs (electricity and maintenance costs). It calculated costs and savings as the difference between a TSL and a base case lacking national standards. It discounted future costs and savings to the present (2010$). DOE calculated a discount factor from the discount rate and the number of years between the year to which the sum is being discounted (2010) and the year in which the costs and savings occur. The NPV is the sum over time (2016–2104) of the discounted net financial savings.

The following sections describe inputs to the NPV calculation that are not described elsewhere.

10.3.2 Inputs

Inputs to the NPV model include cost inputs, inputs important for detailing electricity capacity costs, and several of the inputs used by the NES calculation. This section provides details on those inputs that were not described for the NES or shipments *moELs*. The specific inputs for the NPV are:

1. first cost,
2. operating cost,
3. peak responsibility factor,

4. initial peak load,
5. scalar for electricity price forecast,
6. marginal electricity costs, and
7. discount rate.

Each input is described in detail below.

10.3.2.1 First Cost

The first cost includes all the initial costs incurred with the installation of a distribution transformer. DOE expresses first cost in terms of cost per unit capacity. Specifically, it defines the first cost of acquiring a transformer with the following equation.

$$FC/Cap = (P + Install)/Cap.$$

Where:

FC	=	first cost;
Cap	=	rated capacity of the transformer;
P	=	price of the transformer including shipping, and taxes; and
Install	=	installation cost of the transformer.

The above values were obtained from the LCC calculation as the averages for individual design lines. DOE converted the first cost of a representative design to an estimated average first cost for a distribution of sizes within a particular equipment class. The adjustment incorporates the 0.75 scaling rule and the mapping of design line to equipment class discussed in sections 10.2.2.1 and 10.2.2.2. Costs are expressed in units of 2010$ per kVA of rated transformer capacity. Table 10.3.1 shows the resulting mean first costs per kVA for distribution transformers by EL and equipment class.

Table 10.3.1 First Cost[c] of Distribution Transformers by Trial Standard Level and Equipment Class (2010$/kVA)

Equipment Class	Base	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
1	98.61	100.93	106.50	106.52	110.18	112.05	116.58	152.98
2	30.33	32.58	32.58	32.85	35.41	34.79	37.34	54.70
3	75.31	75.31	97.81	95.54	110.81	110.81	153.61	
4	56.32	63.31	63.31	66.14	73.55	80.13	104.75	
5	41.85	42.12	44.10	44.63	44.63	72.26		
6	33.03	33.22	35.46	35.56	35.56	59.34		
7	55.12	57.51	59.54	69.61	69.61	94.96		
8	39.59	41.09	43.39	51.00	51.00	71.01		
9	51.03	51.93	57.01	57.01	57.01	81.11		
10	39.48	40.17	44.10	44.11	44.11	62.76		

10.3.2.2 Operating Costs

Transformer operating costs are the annual cost of transformer losses. Operating costs are a complex, yet essential, part of calculating the national economic impact of a standard. DOE used distinct costs to calculate the value of various types of losses and peak capacity savings. Potential load growth also requires an adjustment factor. Peak loading, peak load coincidence, and average loading require additional factors to characterize load losses. Finally, DOE used a scalar for the electricity price forecast to characterize future trends in electricity prices consistent with the EIA's *AEO2010* forecast.[4]

In calculating transformer operating costs, DOE assumed zero incremental maintenance costs. It used the following formula to capture the diversity of factors that can affect annual operating costs.

$$OC/Cap = EPFS(y) \times (E_{NL} \times (NLLMCC + 8760 \times NLLMEC) + E_{LL} \times (LAdjust(y))^2 \times (PRF \times PL2 \times LLMCC + 8760 \times RMS2 \times LLMEC))/Cap.$$

Where:

OC	=	the operating cost,
Cap	=	the rated capacity of the transformer,
$EPFS(y)$	=	the scalar for the electricity price forecast for year y,
E_{NL}	=	the no-load losses at rated load,
$NLLMCC$	=	the marginal cost of capacity for no-load losses,
$NLLMEC$	=	the marginal cost of energy for no-load losses,

[c] First cost includes installation cost.

E_{LL}	=	the load losses at rated load,
LAdjust(y)	=	the load growth adjustment factor in year *y*,
PRF	=	the peak responsibility factor,
PL	=	the initial peak load,
LLMCC	=	the marginal cost of capacity for load losses,
RMS	=	the root mean square loading of the transformer, and
LLMEC	=	the marginal cost of energy for load losses.

DOE expressed the operating costs in 2010$ per kVA of rated capacity. As when calculating the NES (sections 10.2.2.1 and 10.2.2.2), DOE also used an adjustment factor to scale to E_{NL} and E_{LL} in order to convert from design line data to equipment class estimates.

10.3.2.3 Peak Responsibility Factor

The transformer peak responsibility factor (PRF) is the fraction of the transformer peak load that is coincident with the system peak, calculated by taking the square of the ratio of the transformer load at the time of the customer peak load to the transformer peak load. In combination with the initial peak load, the PRF is necessary for estimating impacts on capacity costs of transformer load losses. DOE used the average PRF from the hourly and the monthly load analyses for liquid-immersed and dry-type transformers, respectively, as reported in the LCC analysis. Table 10.3.2 presents the PRFs used in the analysis of the 10 equipment classes (ECs).

Table 10.3.2 Peak Responsibility Factors by Equipment Class

	EC 1	EC 2	EC 3	EC 4	EC 5	EC 6	EC 7	EC 8	EC 9	EC 10
PRF	0.27	0.38	0.23	0.23	0.46	0.46	0.46	0.46	0.46	0.46

10.3.2.4 Initial Peak Load

The initial peak load is the annual per-unit peak load on the transformer during the first year of operation. This factor, in combination with the PRF, is necessary for calculating impacts on capacity costs from transformer load losses. The initial peak load is estimated as a percentage of the rated peak load of the transformer. The IEEE (2001)[7] defines a similar, but different, measure of peak transformer load called an “Equivalent Annual Peak Load” that accounts for changes in peak load during the life of the transformer. Rather than use the equivalent annual peak load, DOE used a distribution to characterize a range of initial peak loads. Chapter 6, sections 6.2.3.3 and 6.3.3.3, further describe DOE’s method. Table 10.3.3 presents the initial peak loads used in the NPV analysis for the 10 equipment classes.

Table 10.3.3 Initial Peak Loading by Equipment Class

	EC 1	EC 2	EC 3	EC 4	EC 5	EC 6	EC 7	EC 8	EC 9	EC 10
Initial Peak Load	0.88	0.88	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80

10.3.2.5 Scalar for Electricity Price Forecasts

The scalar for forecasting electricity prices converts current electricity costs into forecasted costs for 2010 through 2104. The scalar is the ratio of the unit cost of electricity in real dollars in a given year to the real cost of electricity in 2010. DOE used forecasts from *AEO2011*[4] to obtain the scalar for electricity price forecasts. For the period beyond 2035, DOE extrapolated the scalar based on the EIA real dollar price trend for 2025–2035.

10.3.2.6 Marginal Electricity Costs

DOE needed to characterize four distinct marginal electricity costs in order to calculate the operating costs of transformers and the financial impact of potential efficiency standards. The four marginal costs are: the marginal capacity cost for no-load losses, (the marginal capacity cost for load losses, the marginal energy cost for no-load losses, and the marginal energy cost for load losses. An electricity system has both energy costs and capacity costs. Depending on the shape of a particular load, the average value of capacity costs may differ from those of energy costs. Because no-load losses and load losses have distinct load shapes, and because different customers experience different load shapes, costs vary both by loss type and by the equipment class of a transformer. DOE therefore used distinct marginal energy and capacity costs for no-load losses and load losses for each transformer equipment class. No transformer size scaling is necessary for the marginal costs, although DOE needed to map design lines to equipment classes (as described in section 10.2.2.2) to convert the design line output from the LCC to equipment class information for calculating the NPV. DOE calculated capacity costs in units of 2010$/kilowatt (kW)/year, and energy costs in units of 2010$/kWh. Table 10.3.4 summarizes the four marginal costs for the 10 equipment classes.

Table 10.3.4 Marginal Energy and Capacity Costs by Equipment Class

Marginal Energy Cost by Equipment Class *$/kWh*										
	EC 1	**EC 2**	**EC 3**	**EC 4**	**EC 5**	**EC 6**	**EC 7**	**EC 8**	**EC 9**	**EC 10**
NLL	0.067	0.067	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
LL	0.073	0.073	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059
Marginal Capacity Cost by Equipment Class *$/kW/year*										
	EC 1	**EC 2**	**EC 3**	**EC 4**	**EC 5**	**EC 6**	**EC 7**	**EC 8**	**EC 9**	**EC 10**
NLL	498.59	498.59	142.62	142.62	142.62	142.62	142.62	142.62	142.62	142.62
LL	197.66	197.66	114.40	114.86	101.46	101.46	101.69	101.47	101.46	101.46

10.3.2.7 Discount Rate

The discount rate, which is the final input to the NPV calculation, expresses the time value of money. DOE used real discount rates of 3 percent and 7 percent, as established by the Office of Management and Budget guidelines on regulatory analysis.[9] The discount rates DOE used in the LCC differ from those used in the NPV calculations, in that the NPV discount rates represent the societal rate of return on capital, whereas LCC discount rates reflect the owner cost of capital and the financial environment of electric utilities and commercial and industrial entities.

10.3.2.8 Projection of Future Product Prices

For reasons discussed in chapter 8 (Section 8.2.1.1), DOE used a constant price assumption for the default forecast in the NIA. In order to investigate the impact of different product price forecasts on the consumer net present value (NPV) for the considered TSLs for medium electric motors, DOE also considered two alternative price trends. Both of these trends are based on a power-law fit on the deflated producer price index for electric power and specialty transformer manufacturing. Details on how these alternative price trends were developed are in appendix 10B, which also presents the results of the sensitivity analysis.

10.4 RESULTS

The following sections summarize the results of the NES and NPV calculations performed for the NIA.

10.4.1 National Energy Savings and Net Present Value for Draft Trial Standard Levels

Table 10.4.1 presents the NES and NPV results from the spreadsheet model for TSLs 1–5 for medium-voltage liquid-immersed and dry-type transformers and TSLs 1–6 for low-voltage dry-type transformers. It should be reiterated that the NES spreadsheet model uses discrete point values rather than a distribution of values for all inputs.

Table 10.4.1 Results for Cumulative National Energy Savings (2016–2045) and Net Present Value (2016–2104)

	Discount Rate (%)	Trial Standard Level						
		1	2	3	4	5	6	7
Liquid-Immersed								
Cumulative Source Savings 2044 (Quads)		0.36	0.74	0.82	1.44	1.42	1.70	2.70
Net Present Value (billion 2010$)	3	3.66	7.39	8.24	14.21	13.48	13.17	-1.11
	7	0.75	1.51	1.73	2.96	2.65	1.76	-8.25
Low-Voltage Dry-Type								
Cumulative Source Savings 2044 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08	
Net Present Value (billion 2010$)	3	7.81	7.79	8.51	11.16	9.37	2.69	
	7	2.03	1.97	2.03	2.36	1.37	-2.41	
Medium-Voltage Dry-Type								
Cumulative Source Savings 2044 (Quads)		0.06	0.13	0.23	0.23	0.37		
Net Present Value (billion 2010$)	3	0.42	0.67	0.90	0.90	-0.38		
	7	0.10	0.13	0.06	0.06	-0.84		

10.4.1.2 Results for Liquid-Immersed Transformers

Figure 10.4.1 illustrates the typical pattern of source energy savings and costs resulting from standards for liquid-immersed transformers. The figure shows the nature of net savings for all six TSLs relative to the base case. The figure also shows the NPV at both a 3-percent and a 7-percent discount rate.

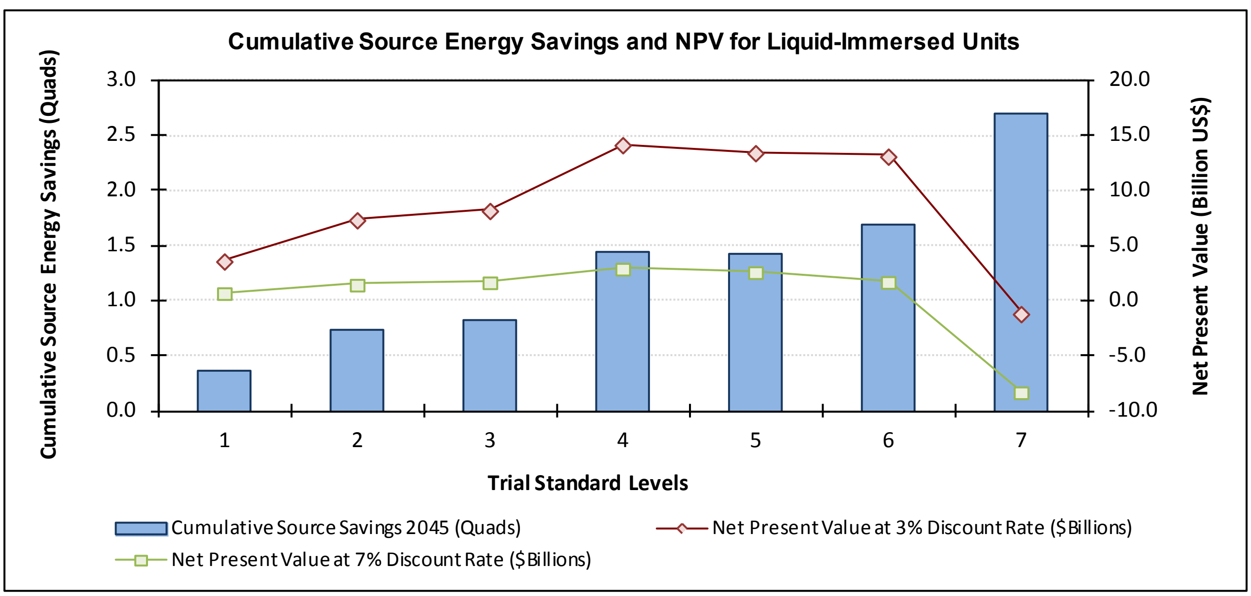

Figure 10.4.1 Liquid-Immersed Distribution Transformers: Impacts of Standards on National Energy Savings and Net Present Value

Figure 10.4.1 shows that, although the savings in energy (quads) are greatest at TSLs 7 (max tech), the associated financial savings decrease at either the 3 percent or 7 percent discount rate. At a discount rate of 3 percent, the NPV of cumulative source savings for liquid-immersed transformers are highest at TSL 4. At a discount rate of 7 percent, the NPV is highest at TSL 4.

10.4.1.3 Results for Low-Voltage Dry-Type Transformers

Figure 10.4.2 shows the pattern of source energy savings and costs resulting from potential standards for low-voltage dry-type transformers. The figure shows the nature of net savings for the six TSLs relative to the base case. The figure also shows the NPV at both a 3-percent and a 7-percent discount rate.

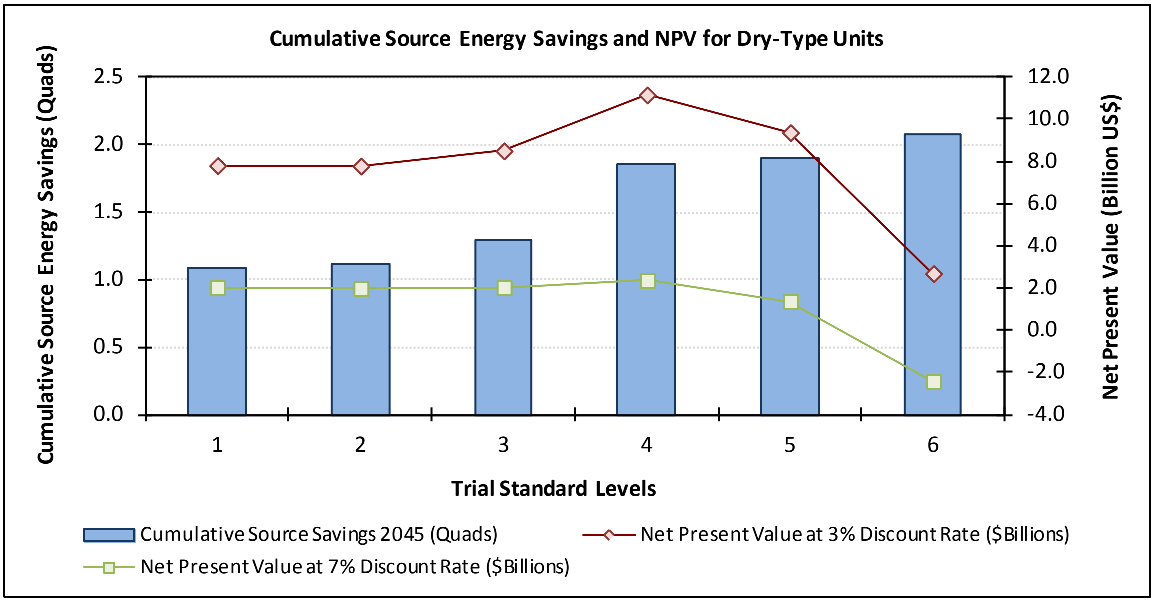

Figure 10.4.2 Low-Voltage Dry-Type Distribution Transformers: Impacts of Standards on National Energy Savings and Net Present Value

Figure 10.4.2 shows that the cumulative savings in energy (quads) is highest under TSLs 6, the associated financial savings decrease dramatically at either discount rate. At a discount rate of 3 percent, the NPV of cumulative source savings for dry-type transformers are highest under TSL4. At a discount rate of 7 percent, the savings are highest under TSL 4.

10.4.1.4 Results for Medium-Voltage Dry-Type Transformers

Figure 10.4.3 illustrates the typical pattern of source energy savings and costs resulting from standards for medium-voltage dry-type transformers. The figure shows the nature of net savings for all five TSLs relative to the base case. The figure also shows the NPV at both a 3-percent and a 7-percent discount rate.

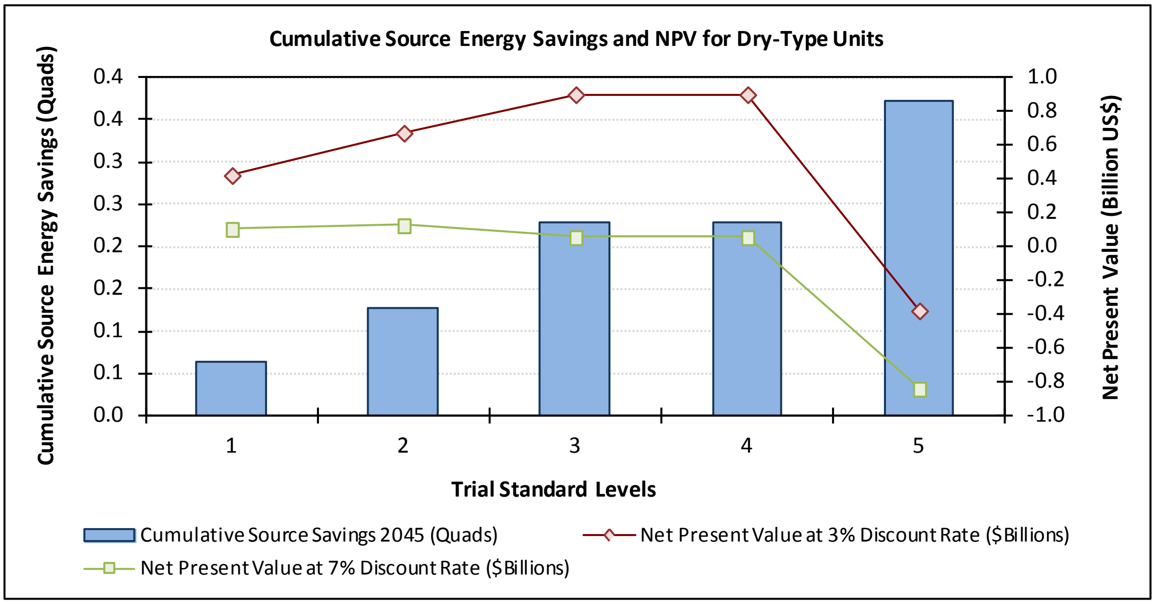

Figure 10.4.3 Medium-Voltage Dry-Type Distribution Transformers: Impacts of Standards on National Energy Savings and Net Present Value

Figure 10.4.3 shows that, although the savings in energy (quads) are greatest at TSLs 5 (max tech), the associated financial savings decrease dramatically at either the 3 percent or 7 percent discount rate. At a discount rate of 3 percent, the NPV of cumulative source savings for medium-voltage dry-type transformers are highest at TSL 4. At a discount rate of 7 percent, the NPV is highest at TSL 3.

10.5 ANNUALIZED NATIONAL COSTS AND BENEFITS

The benefits and costs of the proposed standards for distribution transformers can be expressed in terms of annualized values over the analysis period. The annualized monetary values are the sum of (1) the annualized national economic value of the benefits from operating products that meet the proposed standards (consisting primarily of operating cost savings from using less energy, minus increases in equipment purchase costs, which is another way of representing consumer NPV), and (2) the monetary value of the benefits of emission reductions, including CO_2 emission reductions. The emissions reductions for each TSL are described in chapter 15, and the derivation of the monetary value of the benefits of emission reductions is described in chapter 16 of this TSD. The value of the CO_2 reductions, otherwise known as the Social Cost of Carbon (SCC), is calculated using a range of values per metric ton of CO_2 developed by a recent interagency process. The derivation of the time series of SCC values is discussed in Appendix 16-A of this TSD.

Although combining the values of operating savings and CO_2 reductions provides a useful perspective, two issues should be considered. First, the national operating savings are domestic U.S. consumer monetary savings that occur as a result of market transactions while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and CO_2 savings are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in the 30-year analysis period. The SCC values, on the other hand, reflect the present value of future climate-related impacts resulting from the emission of one ton of carbon dioxide in each year. These impacts go well beyond 2100.

10.5.1 Calculation Method

DOE uses a two-step calculation process to convert each time-series of costs and benefits into annualized values. First, DOE calculates a present value in the "present" year used in discounting the NPV of total consumer costs and savings.[d] For this calculation, DOE uses discount rates of three and seven percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE uses the discount rate appropriate for each SCC time-series (see chapter 16 for discussion).

$$PV_x = \sum_{t=y_1,y_\mathrm{T}} (x(t) \cdot (1 + r_x)^{y_\mathrm{NPV}-t})$$

Where:

$x(t) =$ Time-series under evaluation,
$PV_x =$ Present value of the time-series x,
$y_1 =$ First year in the analysis period,
$y_\mathrm{T} =$ Last year in the analysis period,
$y_\mathrm{NPV} =$ Year to which the NPV of consumers' costs and savings are being discounted,
$r_x =$ Discount rate used to discount the annual values of time-series x to year y_NPV.

In the second step, DOE calculates, from the present values, the fixed annual payments over a 30-year period, starting in the first year of the analysis period (i.e., the compliance year), which yields the same present values with discount rates of three and seven percent. This requires projecting the present values in the "present" year ahead to the compliance year. The fixed annual payments are the annualized values.

$$Ann_{x,r} = PV_x \cdot f_{y_1-y_\mathrm{NPV},r} \cdot a_{30,r} = PV_x \cdot (1+r)^{y_1-y_\mathrm{NPV}} \cdot \frac{r \cdot (1+r)^{30}}{(1+r)^{30}-1}$$

Where:

[d] For the value of emissions reductions, DOE uses a time series that corresponds to the time period used in calculating the operating cost savings (i.e., through the final year in which products shipped are still operating).

$Ann_{x,r}$ = Annualized value of the time-series x,
$f_{n,r}$ = Factor to project a value n years ahead[e] with r discount rate,
$a_{30,r}$ = Factor to annualize present values over a 30-year period with r discount rate.

Although DOE calculates annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined would be a steady stream of payments.

10.5.2 Results for the Proposed Standards

The NOPR associated with this TSD states that DOE is proposing amended energy conservation standards that correspond to TSL 1 for liquid-immersed transformers, TSL 1 for low-voltage dry-type transformers, and TSL 2 for medium-voltage dry-type transformers. Estimates of annualized benefits and costs for the proposed standards are shown in Table 10.5.1.

The Primary, Low Benefits, and High Benefits Estimates utilize forecasts of energy prices from the AEO2011 Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect no change in the Primary estimate, rising product prices in the Low Net Benefits estimate, and declining product prices in the High Net Benefits estimate.

[e] n is the number of years between the "present" year and the compliance year.

Table 10.5.1 Annualized Benefits and Costs of Proposed Standards for Distribution Transformers

	Discount Rate	Primary Estimate*	Low Net Benefits Estimate*	High Net Benefits Estimate*
		Monetized (million 2010$/year)		
Benefits				
Operating Cost Savings	7%	631	594	659
	3%	1,026	950	1,075
CO_2 Reduction at $4.9/t**	5%	58.6	58.6	58.6
CO_2Reduction at $22.3/t**	3%	244	244	244
CO_2Reduction at $36.5/t**	2.5%	389	389	389
CO_2Reduction at $67.6/t**	3%	742	742	742
NO_X Reduction at $2,537/ton**	7%	7.78	7.78	7.78
	3%	12.4	12.4	12.4
Total†	7% plus CO_2 range	697 to 1380	660 to 1343	726 to 1409
	7%	883	846	911
	3%	1097 to 1780	1021 to 1704	1146 to 1829
	3% plus CO_2 range	1,283	1,207	1,331
Costs				
Incremental Product Costs	7%	302	338	285
	3%	308	351	289
Total Net Benefits				
Total†	7% plus CO_2 range	400 to 1083	327 to 1010	445 to 1128
	7%	581	507	626
	3%	789 to 1472	670 to 1353	857 to 1540
	3% plus CO_2 range	975	855	1,043

* The Primary, Low Net Benefits, and High Net Benefits Estimates utilize forecasts of energy prices from the AEO 2011 reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect no change in the Primary estimate, rising product prices in the Low Net Benefits estimate, and declining product prices in the High Net Benefits estimate.
** The CO2 values represent global values (in 2010$) of the social cost of CO2 emissions in 2010 under several scenarios. The values of $4.9, $22.3, and $36.5 per metric ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6 per metric ton represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The value for NOX (in 2010$) is the average of the low and high values used in DOE's analysis.
† Total Benefits for both the 3% and 7% cases are derived using the SCC value calculated at a 3% discount rate, which is $22.3/metric ton in 2010 (in 2010$). In the rows labeled as "7% plus CO2 range" and "3% plus CO2 range," the operating cost and NOX benefits are calculated using the labeled discount rate, and those values are added to the full range of CO2 values.

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CHAPTER 11. LIFE-CYCLE COST SUBGROUP ANALYSIS

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11.1 INTRODUCTION

The life-cycle cost (LCC) subgroup analysis evaluates impacts on any identifiable groups of customers who may, because of their particular socio-economic characteristics, be disproportionately affected by any national energy-efficiency standard level. This chapter of the TSD describes how the Department performed its life-cycle cost consumer subgroup analysis for the distribution transformer energy-efficiency standard rulemaking.

The Department conducted this evaluation for the Notice of Proposed Rulemaking (NOPR), in part, by analyzing the LCC and payback periods for those customers that fall into identified subgroups. For this rulemaking, the Department defined consumer subgroups in terms of utilities that may be disproportionally affected by some installation costs. The specific consumer subgroup that the Department chose to analyze is utilities that install distribution transformers in vaults or other space-constrained sites.

11.2 ANALYSIS APPROACH FOR MUNICIPAL UTILITIES AND RURAL ELECTRIC COOPERATIVES

As part of the regular life-cycle cost analysis, the Department built spreadsheet analysis tools that provide a consumer economic analysis for a nationally representative sample of utilities. The Department developed an approach to perform the consumer subgroup for utilities that serve low populations density customer bases, which the majority of these utilities are either municipal utilities or rural electric cooperatives. These calculations are part its normal life-cycle costs and payback period analysis and are described in chapter 8, section 8.3.4.1 of this TSD.

11.3 ANALYSIS APPROACH FOR PURCHASERS OF VAULT INTALLED TRANSFORMERS

DOE calculated the volumes of those transformers selected by the LCC spreadsheets, as a function of EL, for the two design lines (DLs) for which transformer vault constraints are most likely to be an issue: DL4 and DL5. DOE examined the impacts of increasing transformer volume with regard to costs for vault enlargement. DOE assumed that if the volume of a transformer in a standard case is larger than the volume of the unit in the base case, a vault modification would be warranted.

To estimate the cost of vault modification, DOE compared the difference in volume between the unit selected in the base case against the unit selected in the standard case, and applied fixed and variable costs. In the 2007 notice of data availability[2], DOE estimated the fixed cost as $1,740 per transformer and the variable cost as $26 per transformer cubic foot, in this TSD, these costs were adjusted to 2010$ using the chained price index for non-residential construction for power and communications to $1854 per transformer and $28 per transformer cubic foot. DOE considered instances where it may be extremely difficult to modify existing vaults by adding a Very High Vault Replacement Cost option to the LCC spreadsheet. Under this option, the fixed cost is $30,000 and the variable cost is $733 per transformer cubic foot.

11.4 LIFE-CYCLE COST SUBGROUP RESULTS

This section presents the results of the LCC subgroups analysis for utilities that experience vault replacement costs. The section presents the results for each design line in the form of tables that report the efficiency level, the mean LCC savings, and the fraction of transformers that have net savings, no impact, and net LCC cost (i.e., negative savings).

11.4.1 Vault Installation Results

The LCC results for the vault installation subgroup are a reflection of the increased costs associated with installing a transformer that meets each EL that is the same, or of less volume then the transformer selected in the basecase. Vault enlargement generally decreases the potential savings due to increased first cost for the new transformer.

Table 11.4.1 Design Line 4, Medium Vault Modification Costs Life-Cycle Cost Results

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.16	99.22	99.25	99.31	99.42	99.50	99.60
Transformers with Net LCC Cost (%)	40.26	59.10	59.10	59.08	58.15	62.85	74.64
Transformers with No Change in LCC (%)	0.58	0.58	0.58	0.58	0.17	0.00	0.00
Transformers with Net LCC Benefit (%)	59.16	40.32	40.32	40.34	41.68	37.15	20.33
Mean LCC Savings ($)	-422	106.4	106.4	112.6	134.0	-390	-2358
Median LCC Savings ($)	435	-346.6	-346.6	-345.2	-332.3	-880	-2887

Table 11.4.2 Design Line 5, Medium Vault Modification Costs Life-Cycle Cost Results

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.48	99.51	99.54	99.57	99.61	99.69
Transformers with Net LCC Cost (%)	45.76	36.25	32.82	28.07	28.21	68.78
Transformers with No Change in LCC (%)	0.00	0.00	0.00	0.00	0.00	0.00
Transformers with Net LCC Benefit (%)	54.24	63.75	67.18	71.17	71.03	28.55
Mean LCC Savings ($)	1062	3203	3854	4689	4270	-5996
Median LCC Savings ($)	1152	3537	4098	4925	4554	-6151

11.5 PAYBACK PERIOD RESULTS

As described in more detail in section 8.6, a common technique for evaluating investment decisions is to perform a payback period (PBP) analysis. A more energy-efficient device will usually cost more to purchase than a device of standard energy efficiency, while the more efficient device will usually cost less to operate. Operating expenses decrease due to a reduction in energy use. The payback period is the time (usually expressed in years) it takes to recover the additional first cost of the efficiency device with its energy cost savings. Because the Department analyzes the economics of a nationally representative distribution of transformers, DOE provides results in terms of a distribution of payback periods.

There are several potential complications to performing an analysis of a distribution of PBP estimates that are discussed in more detail in section 8.6. Specifically, a payback period is a ratio of increased first cost and decreased operating expenses. When there is a distribution of changes for both first cost and operating expense reductions, the average of the ratio does not equal the ratio of the averages. Therefore, in the tables below, the Department reports all quantities of interest: the mean PBP, the average increase in first cost, and the average decrease in annual operating expenses (in the first year of operation). These quantities allow stakeholders to compare the average PBP to a ratio of the average first cost increase and the average operating cost decrease. These two values are comparable, but not equal because not all transformer purchase decision computations have well-defined PBPs.

11.5.1 Vault Installation Results

The PBP results for the vault installed subgroup are a reflection of the increased costs associated with vault enlargement. Vault enlargement decreases the potential savings due to increased installation costs that are required to install the new transformer.

Table 11.5.1 Design Line 4, Medium Vault Modification Costs Payback-Period Results

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	32.0	17.1	17.1	17.1	17.1	19.2	24.5
Median Payback (Years)	9.1	18.8	18.8	18.8	18.7	19.9	24.3
Transformers having Well Defined Payback (%)	99.37	99.27	99.27	99.33	99.81	99.94	94.96
Transformers having Undefined Payback (%)	0.63	0.73	0.73	0.67	0.19	0.06	0.01
Mean Incremental First Cost ($)	5,894	6,443	6,443	6,451	6,536	7,615	10,601
Mean Operating Cost Savings ($)	6,095	8,154	8,154	8,153	8,247	8,888	9,067
Payback of Average Transformer (Years)	668	483	483	482	471	400	334

Table 11.5.2 Design Line 5, Medium Vault Modification Costs Payback-Period Results

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	23.3	19.8	18.4	16.7	16.6	22.9
Median Payback (Years)	14.2	13.1	13.6	13.6	14.6	21.1
Transformers having Well Defined Payback (%)	91.61	96.04	98.90	99.08	99.21	97.33
Transformers having Undefined Payback (%)	8.39	3.96	1.10	0.16	0.03	0.00
Mean Incremental First Cost ($)	28,609	29,108	31,098	32,138	35,591	56,788
Mean Operating Cost Savings ($)	17,010	17,101	17,331	17,509	18,026	18,224
Payback of Average Transformer (Years)	3,409	3,259	3,100	2,989	2,794	2,185

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CHAPTER 12. MANUFACTURER IMPACT ANALYSIS

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CHAPTER 12. MANUFACTURER IMPACT ANALYSIS

12.1 INTRODUCTION

In determining whether a standard is economically justified, the U.S. Department of Energy (DOE) is required to consider "the economic impact of the standard on the manufacturers and on the consumers of the products subject to such a standard." (42 U.S.C. 6312(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 distribution transformers, 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 the equipment 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 base 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 distribution transformer industry, including data on market share, sales volumes and trends, pricing, employment, and financial structure. In Phase II, "Industry Cash Flow," DOE used the GRIM to assess the impacts of amended energy conservation standards on distribution transformers.

In Phase II, DOE created a GRIM for distribution transformers and an interview guide to gather information on the potential impacts on manufacturers. DOE presented the MIA results for distribution transformers based on a set of considered TSLs. These TSLs are described in Section 12.4.5 below.

In Phase III, "Subgroup Impact Analysis," DOE interviewed manufacturers representing 75 percent of liquid-immersed transformer sales, 75 percent of medium-voltage dry-type transformer sales, and 50 percent of low-voltage dry-type transformer sales. Interviewees included large and small manufacturers with various market shares and market focus, providing a representative cross-section of the industries. During interviews, DOE discussed financial topics specific to each manufacturer and obtained each manufacturer's view of the industry. The interviews provided DOE with valuable information for evaluating the impacts of amended energy conservation standards on manufacturer cash flows, investment requirements, and employment.

12.2.1 Phase I: Industry Profile

In Phase I of the MIA, DOE prepared a profile of the distribution transformer industry that built upon the market and technology assessment prepared for this rulemaking (see Chapter 3 of this Technical Support Document). Before initiating the detailed impact studies, DOE collected information on the present and past structure and market characteristics of each industry. This information included market share data, unit shipments, manufacturer markups, and the cost structure for various manufacturers. The industry profile includes: (1) further detail on the overall market and equipment 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 distribution transformer manufacturers that DOE used to derive 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 distribution transformer industry, including Securities and Exchange Commission (SEC) 10–K reports, Standard & Poor's (S&P) stock reports, and corporate annual reports. DOE supplemented this public information with data released by privately held companies.

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 distribution transformers. More stringent energy conservation standards can affect manufacturer cash flows in three distinct ways: (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 distribution transformers. 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.

In Phase II, DOE grouped the cash flow results for design lines made by the same sets of manufacturers serving the same markets to assess the impacts of amended energy conservation standards with more granularity. DOE presented the MIA cash flow results for this rulemaking in three classes: liquid-immersed transformers, medium-voltage dry type transformers, and low-voltage dry type transformers. The Department believes that modeling the industry in separate ”superclasses” offers a robust analytical approach for three reasons:

1. Customer profiles and market mechanisms – Generally, the profiles of the majority of customers purchasing transformers and the manner in which they are built and sold within each of the superclasses are distinct. Discussion of customer profiles and distribution chains can be found in the LCC analysis (Chapter 11 of the TSD).

2. Manufacturing equipment and transformer design – The equipment necessary for production and the methods by which manufacturers build transformers are different for each of the superclasses. For example, in the liquid-immersed superclass, transformer cores tend to be wound, requiring distributed gap core winding machines, annealing furnaces, tanking machines, and other equipment that is commonly used in this superclass. Accordingly, the capital equipment investment necessary for compliance with a particular TSL typically differs between the superclasses.

3. Industry structure – Reviewing the database of transformer manufacturers, the Department observed that many companies operate and specialize in one of the distribution transformer superclasses. For large companies that operate in more than one superclass, each manufacturing facility tends to be dedicated to producing transformers from one of the superclasses. Thus, the industry naturally breaks down into three superclasses.

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 several years after the standards’ compliance date. These factors include annual expected revenues, costs of sales, SG&A, taxes, and capital expenditures related to the amended standards. Inputs to the GRIM include manufacturing production costs, selling prices, and shipments forecasts developed in other analyses. DOE derived the manufacturing costs from the engineering analysis and information provided by the industry and 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 base case projections for the industry. The financial impact of amended energy conservation standards is the difference between the discounted annual cash flows in the base case and standards case at each TSL.

12.2.2.2 Interview Guides

During Phase III of the MIA, DOE interviewed manufacturers to gather information on the effects of amended energy conservation on revenues and finances, direct employment, capital assets, and industry competitiveness. Before the interviews, DOE distributed an interview guide for the distribution transformer industry. The interview guide provided a starting point to identify relevant issues and help identify the impacts of amended energy conservation standards on individual manufacturers or subgroups of manufacturers. Most of the information DOE received from these meetings is protected by non-disclosure agreements and resides with DOE's contractors. Before each telephone interview or site visit, DOE provided company representatives with an interview guide that included the topics for which DOE sought input. The MIA interview topics included (1) key issues to this rulemaking; (2) company overview and organizational characteristics; (3) manufacturer markups and profitability; (4) distribution channels; (5) shipment projections and market shares; (6) financial parameters; (7) conversion costs; (8) cumulative regulatory burden; (9) direct employment impact assessment; (10) manufacturing capacity, foreign competition, and outsourcing; (11) consolidation, and (12) impacts on small business. The interview guides are presented in Appendix 12A.

12.2.3 Phase III: Subgroup Analysis

Using average cost and financial assumptions to develop an industry cash flow model is not adequate for assessing differential impacts among subgroups of manufacturers. Smaller manufacturers, niche players, or manufacturers exhibiting a cost structure that differs largely from the industry average could be more negatively impacted. As a result, DOE will analyze small business manufacturers as a subgroup.

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 interested parties to express their views on important issues privately, allowing confidential or sensitive information to be considered in the rulemaking process.

DOE used these interviews to tailor the GRIM to reflect unique financial characteristics for distribution transformer manufacturers. DOE contacted companies from its database of manufacturers and interviewed small and large companies, subsidiaries and independent firms, and public and private corporations to provide an accurate representation of the 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 helped 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 models based on this feedback. Section 12.4 provides more information on how DOE calculated the parameters.

The Department conducted structured, detailed, face-to-face interviews with seven manufacturers, some of which produce transformers in more than one superclass. Three of the seven manufacturers are small businesses. Three of the manufacturers produce liquid-immersed transformers, collectively representing approximately 65 percent of the U.S. liquid-immersed market. Two of the manufacturers produce medium-voltage dry-type transformers, collectively representing approximately 75 percent of the U.S. medium-voltage dry-type market. Three of the manufacturers produce low-voltage dry-type transformers, collectively representing approximately 30 percent of the U.S. low-voltage dry-type market. DOE also conducted many more phone interviews and follow-up discussions with transformer manufacturers, particularly small businesses, to gather important information about their businesses and their perspectives on amended standards. Additionally, DOE gained invaluable insights during the many stakeholder negotiations when manufacturers openly discussed their businesses and concerns with amended standards.

12.2.3.3 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 published on August 22, 2008, as amended, and the North American Industry Classification System (NAICS) code, presented in Table 12.2-1, to determine whether any small entities would be affected by the rulemaking.[a] 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 12.2-1 SBA and NAICS Classification of Small Businesses Potentially Affected by This Rulemaking

Industry Description	Revenue Limit	Employee Limit	NAICS
Power, Distribution and Specialty Transformer Manufacturing	N/A	750	335311

DOE used the National Electrical Manufacturers Association (NEMA)[1] member directory to identify manufacturers of distribution transformers. DOE also utilized information from previous rulemakings, UL qualification directories, individual company websites, and market research tools (e.g., Hoover's reports) to create a list of companies that potentially manufacture distribution transformers covered by this rulemaking. Additionally, DOE also asked interested parties and industry representatives if they were aware of other small business

[a] The size standards are available on the SBA's website at http://www.sba.gov/content/table-small-business-size-standards

manufacturers. DOE contacted select companies on its list, as necessary, to determine whether they met the SBA's definition of a small business manufacturer of covered distribution transformers. DOE screened out companies that did not offer products covered by this rulemaking, did not meet the definition of a "small business," or are foreign owned and operated.

During its research, DOE identified approximately 30 companies which manufacture products covered by this rulemaking and qualify as small businesses per the applicable SBA definition. DOE contacted the small businesses to solicit feedback on the potential impacts of energy conservation standards. Two of the small businesses consented to being interviewed during the face-to-face MIA interviews and plant tours, while DOE's contractor also received feedback from several additional small businesses through phone interviews and email correspondence. In addition to posing the standard MIA interview questions, DOE solicited data from manufacturers on differential impacts that small companies might experience from amended energy conservation standards. Because DOE was not able to certify that the proposed rulemaking would not have a significant economic impact on a substantial number of small entities, DOE has analyzed small manufacturers as a subgroup. The results of this subgroup analysis are presented in Section 12.6.

12.2.3.3 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 and North America, 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 12.4.8; DOE's discussion of the capacity impact can be found in Section 12.7.2.

12.2.3.4 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 distribution transformer 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 12.7.1.

12.2.3.5 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 equipment. DOE analyzed the impact on manufacturers of multiple, product-specific regulatory actions. Based on its own research and discussions with manufacturers, DOE identified regulations relevant to distribution transformer manufacturers, such as State regulations and other Federal regulations that impact other products made by the same manufacturers. Discussion of the cumulative regulatory burden can be found in Section 12.7.3.

12.3 MANUFACTURER IMPACT ANALYSIS KEY ISSUES

Each MIA interview starts by asking: "What are the key issues for your company regarding the energy conservation standard rulemaking?" This question prompts manufacturers to identify the issues they feel DOE should explore and discuss further during the interview. The following sections describe the most significant issues identified by manufacturers. These summaries are provided in aggregate to protect manufacturer confidentiality.

12.3.1 Conversion costs and stranded assets

For manufacturers of distribution transformers, liquid-immersed, medium-voltage dry-type, and low-voltage dry-type, conversion costs and stranded assets are a major concern. All manufacturers stated that efficiency levels that require the use of amorphous steel would sharply increase conversion costs. Due to the thickness and brittleness of amorphous steel, unique production processes and new material handling processes must be applied. Manufacturers noted that they would need to make extensive capital investments in amorphous core production equipment, including core cutting machines, annealing ovens, and lacing tables.

Dry-type manufacturers also stated that a standard that moves the industry to silicon steel wound cores would also greatly increase conversions costs. Since the vast majority of dry type manufacturers produce stacked cores, a move to wound cores would lead to extensive stranded assets. In some cases, manufacturers may consider purchasing prefabricated cores rather than modifying their facilities to produce wound cores due to the extensive conversion costs.

Additionally, dry-type manufactures stated that a revised standard that does not require amorphous steel or wound core designs could still lead to capital conversion costs. As the standard increases, manufacturers are likely to use higher grade steels for core production. Because high grade steels tend to be thinner, additional Georg machines, core assembly lines and workstations, custom miter cutters, and panel boards may be needed in order to maintain existing throughput levels.

Some manufacturers mentioned that stranded assets may also be an issue when equipment needs to be retired and/or replaced if it cannot be repurposed for higher efficiency designs. DOE accounted for stranded assets in the GRIM.

12.3.2 Shortage of Materials

There is currently a limited supply of M4, M3, M2, ZDMH, H-0 DR, and SA1 amorphous steels on the market and manufacturers expressed concern that higher standards may increase both demand and prices. Of these steels, M4 and M3 steels are currently the most widely produced, with suppliers such as AK Steel, Allegheny Ludlum, ThyssenKrupp, Nippon, JFE, Wuhan, Novolipetsk, Posco, ArcelorMittal, Orb, Baosteel, Stalproduct, Angang, and Arcelor/Hunan. However, as the grade of grain-oriented electrical steel improves, its availability decreases. M2 is a higher grade than M3 but it is produced by fewer suppliers, such as AK Steel, Allegheny Ludlum, ThyssenKrupp, Nippon, and JFE. The availability of mechanically-scribed, deep domain-refined steel such as ZDMH, H-0 DR, and SA1 amorphous is even more limited. ZDMH is only produced by Nippon, JFE, and AK Steel, and H-0 DR is only produced by Nippon, JFE, AK Steel, Posco, and Baosteel. Amorphous steel is only produced by Hitachi (MetGlas) and AT&M. However, AT&M only supplies the Chinese market. If efficiency levels are set so high that only amorphous can be used, then domestic manufacturers may be subject to monopolistic pricing from a sole supplier.

In addition to being in limited supply, higher efficiency steels are also 1) more expensive, 2) subject to tariffs when imported from a foreign supplier, 3) subject to long lead times for both domestic and international suppliers, and 4) difficult to obtain for manufacturers that do not have contracts in place with suppliers. Furthermore, due in part to the major capital investment required to build a steel plant, barriers to entry are high and capacity cannot be easily increased. All these factors contribute to the limited availability of higher efficiency steel for transformer manufacturers.

12.3.3 Compliance and Enforcement

Manufacturers indicated the importance of compliance and enforcement. Some manufacturers are concerned that insufficient enforcement could result in an unfair competitive advantage for some companies who opt not to comply. Manufacturers were particularly concerned about importers of foreign manufactured products.

With regard to low-voltage dry-type transformers, some manufacturers are concerned that higher standards could lead to customers to shift from low-voltage dry-type transformers that are within the scope of DOE coverage to low-voltage dry-type transformers that are outside the scope of DOE coverage. The market for products within the scope of DOE coverage and the market for products outside the scope of DOE coverage are approximately equal in terms of revenue. As a result, if standards increase for products that are in-scope, there may be an increase in the manufacturing of products that are out-of-scope because they will not be subject to the same compliance burdens. Some of these out-of-scope products are highly inefficient. Therefore, manufacturers are concerned that, if those products are more widely adopted, the total energy savings from this rulemaking may be less than projected.

12.3.4 Effective Date

Manufacturers expressed concerns about the amount of time available to adapt to an amended standard. Manufacturers indicated that a transition period longer than three years is needed to meet a new standard, especially if the standard requires a very high efficiency level and a technology change, like a transition to amorphous material. In order to avoid stranding too many assets and materials, sufficient time must be given to manufacturers for the purchase and use of new equipment, development of new designs if needed, and transitioning of customers to new product offerings. Also, some manufacturers stated that standards for low-voltage dry-type transformers, which were not included in the previous 2007 rulemaking, should be on an extended timeline.

12.3.5 Size and Weight Constraints

Manufacturers were concerned that their customers' dimensional and physical constraints would not be able to accommodate designs required to meet higher energy efficiency standards. In particular, manufacturers voiced concern regarding retrofit applications, mining applications, telephone pole capacities, and other installations where transformers have to comply with size and weight constraints.

12.3.6 Emergency Situations

For liquid-immersed transformer manufacturers, the ability to obtain waivers during emergency situations is an important issue. For example, when a natural disaster occurs, there may be a sharp increase in demand for transformers and manufacturers may not be able to meet DOE's efficiency requirements under these circumstances due to limitations of high efficiency steel availability. In order to adequately supply areas facing such emergency situations, manufacturers need to produce transformers as quickly as possible.

12.4 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.

12.4.1 Overview of the GRIM

The basic structure of the GRIM, illustrated in Figure 12.4-1, is an annual cash flow analysis that uses manufacturer prices, manufacturing costs, shipments, and industry financial information as inputs, and accepts a set of regulatory conditions such as changes in costs, investments, and associated margins. The GRIM spreadsheet uses a number of inputs to arrive at a series of annual cash flows, beginning with the base year of the analysis, 2011, and continuing to 2045. The model calculates the INPV by summing the stream of annual discounted cash flows during this period and adding a discounted terminal value. [2]

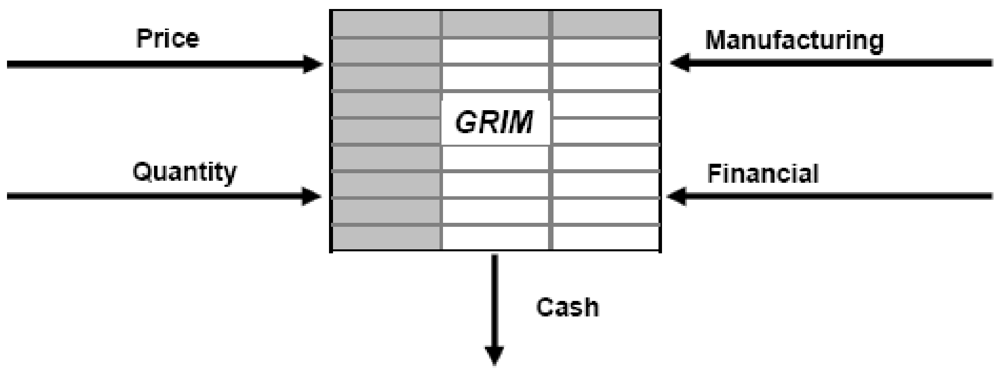

Figure 12.4-1 Using the GRIM to Calculate Cash Flow

The GRIM projects cash flows using standard accounting principles and compares changes in INPV between the base case and the standard-case scenario induced by amended energy conservation standards. The difference in INPV between the base case and the standard case(s) represents the estimated financial impact of the amended energy conservation standard on manufacturers. Appendix 12B provides more technical details and user information for the GRIM.

12.4.2 Sources for GRIM Inputs

The GRIM uses several different sources for data inputs in determining industry cash flow. These sources include corporate annual reports, company profiles, Census data, credit ratings, the shipments model, the engineering analysis, and the manufacturer interviews.

12.4.2.1 Corporate Annual Reports

Corporate annual reports to the SEC (SEC 10-Ks) provided many of the initial financial inputs to the GRIM. These reports exist for publicly held companies and are 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 distribution transformers, among other products. Since these companies do not provide detailed information about their individual product lines, DOE used financial information at the parent company level 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 distribution transformer manufacturing. DOE used corporate annual reports to derive the following initial inputs to the GRIM:

- Tax rate
- Working capital
- SG&A
- R&D
- Depreciation
- Capital expenditures
- Net PPE

12.4.2.2 Standard and Poor Credit Ratings

S&P provides independent credit ratings, research, and financial information. DOE relied on S&P reports to determine the industry's average cost of debt when calculating the cost of capital.

12.4.2.3 Shipment Model

The GRIM used shipment projections derived from DOE's shipments model in the NIA. The model relied on historical shipments data for distribution transformers. Chapter 9 of the TSD describes the methodology and analytical model DOE used to forecast shipments.

12.4.2.4 Engineering Analysis

Using several transformer design characteristics in the Engineering Analysis, DOE developed ten equipment classes. Within each of these equipment classes, DOE further classified distribution transformers by their kilovolt-ampere (kVA) rating. These kVA ratings are essentially size categories, of which there are more than 100 across all ten equipment classes in this rulemaking. Because DOE found that many of the units share similar designs and construction methods, DOE simplified the analysis by creating engineering design lines (DLs), which group kVA ratings based on similar principles of design and construction. After developing its DLs, DOE then selected one representative unit from each DL for study in the engineering analysis, greatly reducing the number of units for direct analysis. For each representative unit, DOE generated hundreds of unique designs by contracting with Optimized Program Services, Inc. (OPS), a software company specializing in transformer design. DOE obtained thousands of transformer designs for each representative unit. The performance of these designs ranged in efficiency from a baseline level, equivalent to the current distribution transformer energy conservation standards, to a theoretical max-tech efficiency level.

After generating each design, DOE used the outputs of the OPS software to create a manufacturer selling price (MSP). The material cost outputs of the OPS software, along with labor estimates were marked up for scrap factors, factory overhead, shipping, and non-production costs to generate an MSP for each design. Thus, DOE obtained a cost versus efficiency relationship for each representative unit. Finally, after DOE had generated the cost-efficiency relationship for each representative unit, it extrapolated the results for the other unanalyzed kVA ratings within that same engineering design line.

12.4.2.5 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);
- 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;
- possible profitability impacts;
- impacts on small businesses; and
- cost-efficiency curves calculated in the engineering analysis.

12.4.3 Financial Parameters

Table 12.4-1 below provides financial parameters for five public companies engaged in manufacturing and selling distribution transformers. The values listed are averages over a 6-year period (2005 to 2010) and include manufacturers from all transformer superclasses.

Table 12.4-1 GRIM Financial Parameters Based on 2005–2010 Weighted Company Financial Data

Parameter	Weighted Average	Manufacturer				
		A	B	C	D	E
Tax Rate *% of taxable income*	22.9	24.1	18.7	3.8	28.2	24.1
Working Capital *% of revenues*	16.1	25.5	10.9	10.4	8.9	13.3
SG&A *% of revenues*	16.5	15.7	19.0	17.0	16.4	20.7
R&D *% of revenues*	3.6	3.2	2.1	2.8	4.5	1.1
Depreciation *% of revenues*	3.2	1.9	2.4	3.9	4.8	3.2
Capital Expenditures *% of revenues*	3.3	2.8	2.0	2.7	4.6	2.1
Net PPE *% of revenues*	14.4	12.0	12.4	18.6	16.1	9.2

During interviews, distribution transformer manufacturers were asked to provide their own figures for the parameters listed in Table 12.4-1. Where applicable, DOE adjusted the parameters in the GRIM using this feedback and data from publicly traded companies to reflect the distribution transformer industry. Table 12.4-2 presents the revised parameters for distribution transformer manufacturers broken out into the three superclasses – liquid-immersed, medium-voltage dry-type, and low-voltage dry-type.

Table 12.4-2 GRIM Revised Distribution Transformer Industry Financial Parameters

Parameter	Revised Estimates		
	Liquid-immersed	Medium-voltage Dry-type	Low-voltage Dry-type
Tax Rate *% of taxable income*	23.0	23.0	23.0
Working Capital *% of revenues*	19.4	18.0	16.0
SG&A *% of revenues*	13.4	12.5	13
R&D *% of revenues*	3.0	3.0	3.0
Depreciation *% of revenues*	2.5	2.0	3.2
Capital Expenditures *% of revenues*	3.0	2.3	3.0
Net PPE *% of revenues*	14.4	14.4	14.4

12.4.4 Corporate Discount Rate

DOE used the weighted-average cost of capital (WACC) as the discount rate to calculate the INPV. A company's assets are financed by a combination of debt and equity. The WACC is the total cost of debt and equity weighted by their respective proportions in the capital structure of the industry. DOE estimated the WACC for the distribution transformer industry based on several representative companies, using the following formula:

WACC = After-Tax Cost of Debt x (Debt Ratio) + Cost of Equity x (Equity Ratio) *Eq. 1*

The cost of equity is the rate of return that equity investors (including, potentially, the company) expect to earn on a company's stock. These expectations are reflected in the market price of the company's stock. The capital asset pricing model (CAPM) provides one widely used means to estimate the cost of equity. According to the CAPM, the cost of equity (expected return) is:

Cost of Equity = Riskless Rate of Return + β x Risk Premium *Eq. 2*

where:

Riskless rate of return is the rate of return on a "safe" benchmark investment, typically considered the short-term Treasury Bill (T-Bill) yield.

Risk premium is the difference between the expected return on stocks and the riskless rate.

Beta (β) is 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 determined that the industry average cost of equity for the distribution transformer industry is 14.5 percent.

Table 12.4-3 Cost of Equity Calculation

Parameter	Industry-Weighted Average %	Manufacturer				
		A	B	C	D	E
(1) Average Beta	1.52	1.50	1.55	1.42	1.58	1.65
(2) Yield on 10-Year T-Bill (1928-2009)	5.23	-	-	-	-	-
(3) Market Risk Premium (1928-2009)	6.09	-	-	-	-	-
Cost of Equity (2)+[(1)*(3)]	14.48	-	-	-	-	-
Equity/Total Capital	76.62	93.1	69.3	68.6	62.4	66.8

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 all five manufacturers by using S&P ratings 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 return because it captures long-term inflation expectations and is less volatile than short-term rates. The risk free rate is estimated to be approximately 5.2 percent, which is the average 10-year Treasury bond return between 1928 and 2010.

For the cost of debt, S&P's Credit Services provided the average spread of corporate bonds for the five public manufacturers. DOE added the industry-weighted average spread to the average T-Bill rate. 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 12.4-4 presents the derivation of the cost of debt and the capital structure of the industry (i.e. the debt ratio (debt/total capital)).

Table 12.4-4 Cost of Debt Calculation

Parameter	Industry-Weighted Average %	Manufacturer				
		A	B	C	D	E
S&P Bond Rating	--	A	A	A-	A+	BB
(1) Yield on 10-Year T-Bill (1928-2009)	5.23	-	-	-	-	-
(2) Gross Cost of Debt	6.21	6.23	6.23	6.33	6.08	8.58
(3) Tax Rate	23.4	24.1	18.7	3.8	28.2	24.1
Net Cost of Debt (2) x (1-(3))	6.21	-	-	-	-	-
Debt/Total Capital	23.38	6.86	30.70	31.36	37.55	33.18

Using public information for these five companies, the initial estimate for the distribution transformer industry's WACC was approximately 12.2 percent. Subtracting an inflation rate of 3.1 percent between 1928 and 2010, the inflation-adjusted WACC and the initial estimate of the discount rate used in the straw-man GRIM is 9.1 percent. DOE also asked for feedback on the 9.1 percent discount during manufacturer interviews and used this feedback to determine that the following WACCs for each superclass were appropriate discount rates for use in the GRIM: 7.4 percent for liquid-immersed, 9 percent for medium-voltage dry-type, and 11.1 percent for low-voltage dry-type.

12.4.5 Trial Standard Levels

DOE developed TSLs for distribution transformers. Consistent with the engineering analysis, DOE analyzed 10 equipment classes, which were subdivided into 14 design lines with 14 representative units. Tables 12.4-5 through 12.4-7 show the efficiency levels (EL) at each TSL for the design lines analyzed by DOE. DOE scaled the standards for these representative equipment classes to create standards for other equipment classes that were not directly analyzed, as set forth in Chapter 5 of the TSD.

Table 12.4-5 Trial Standard Levels for Liquid Immersed Distribution Transformers

Design Line	Transformer Type, Rep Unit kVA, and Phase Count	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
1	Liquid-Immersed, 50kVA, single-phase	EL 1	EL 1	EL 1	EL 2	EL 3	EL 4	EL 6
2	Liquid-Immersed, 25kVA, single-phase	Base	EL 1	EL 1	EL 2	EL 3	EL 4	EL 6
3	Liquid-Immersed, 500kVA, single-phase	EL 1	EL 1	EL 2	EL 4	EL 3	EL 5	EL 7
4	Liquid-Immersed, 150kVA, three-phase	EL 1	EL 1	EL 1	EL 2	EL 3	EL 4	EL 7
5	Liquid-Immersed, 1500kVA, three-phase	EL 1	EL 1	EL 2	EL 4	EL 3	EL 5	EL 7

TSL 1 represents a set of efficiency levels in which there is a diversity of electrical steels that are cost-competitive and economically feasible for all design lines. TSL 2 represents EL1 for all design lines. TSL 3 represents the maximum efficiency level achievable with M3 core steel. TSL 4 represents the maximum NPV at a 7 percent discount rate. TSL 5 represents EL 3 for all design lines. TSL 6 represents the maximum source energy savings with positive NPV at a 7 percent discount rate. TSL 7 represents the maximum technologically feasible level (max tech).

Table 12.4-6 Trial Standard Levels for Low-Voltage Dry-Type Distribution Transformers

Design Line	Transformer Type, Rep Unit kVA, and Phase Count	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
6	Low-Voltage Dry-Type, 25kVA, single-phase	Baseline	EL 3	EL 4	EL 6	EL 6	EL 7
7	Low-Voltage Dry-Type, 75kVA, three-phase	EL 2	EL 3	EL 4	EL 6	EL 6	EL 7
8	Low-Voltage Dry-Type, 300kVA, three-phase	EL 2	EL 2	EL 4	EL 6	EL 7	EL 7

TSL 1 represents the maximum efficiency level achievable with M6 core steel. TSL 2 represents NEMA premium levels. TSL 3 represents the maximum efficiency achievable using butt-lap miter core manufacturing for single-phase distribution transformers and full miter core manufacturing for three-phase distribution transformers. TSL 4 represents the maximum NPV at a 7 percent discount rate. TSL 5 represents the maximum source energy savings with positive NPV at a 7 percent discount rate. TSL 6 represents the maximum technologically feasible level (max tech).

Table 12.4-7 Trial Standard Levels for Medium-Voltage Dry-Type Distribution Transformers

Design Line	Transformer Type, Rep Unit kVA, and Phase Count	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
9	Medium-Voltage Dry-Type, 300kVA, three-phase, 45kV BIL	EL 1	EL 1	EL 2	EL 2	EL 6
10	Medium-Voltage Dry-Type, 1500kVA, three-phase, 45kV BIL	EL 1	EL 2	EL 2	EL 2	EL 6
11	Medium-Voltage Dry-Type, 300kVA, three-phase, 95kV BIL	EL 1	EL 1	EL 4	EL 4	EL 6
12	Medium-Voltage Dry-Type, 1500kVA, three-phase, 95kV BIL	EL 1	EL 2	EL 4	EL 4	EL 7
13A	Medium-Voltage Dry-Type, 300kVA, three-phase, 125kV BIL	EL 1	EL 1	EL 4	EL 4	EL 7
13B	Medium-Voltage Dry-Type, 2000kVA, three-phase, 125kV BIL	EL 1	EL 2	EL 4	EL 4	EL 5

TSL 1 represents EL1 for all design lines. TSL 2 represents a set of efficiency levels in which there is a diversity of electrical steels that are cost-competitive and economically feasible for all design lines. TSL 3 represents the maximum NPV at a 7 percent discount rate. TSL 4 represents the maximum source energy savings with positive NPV at a 7 percent discount rate. TSL 5 represents the maximum technologically feasible level (max tech).

12.4.6 NIA Shipment Forecast

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 used the NIA's annual shipment forecasts from 2011 to 2045, the end of the analysis period. The shipments analysis assumes that growth in distribution transformer shipments will be driven by long-term growth in electricity consumption. DOE's shipments analysis also includes an elasticity factor based on the potential for transformers purchasers to elect to refurbish rather than replace failed transformers as the purchase price increases. The assumptions and methodology that drive this analysis are described in Chapter 9 of the NOPR TSD.

12.4.7 Production Costs

During the engineering analysis, the Department used transformer design software to create a database of designs spanning a broad range of efficiencies for each of the representative units. This design software generated a bill of materials, with information including pounds of core steel, pounds of conductor, insulation, ducting, and tank size. The software also provided information pertaining to the labor necessary to construct the transformer, including the number of turns in the windings, and core dimensions, including stack height. All the components from this bill of materials and labor estimate were combined with fixed hardware costs, such as bushings, busbar, and terminals. The Department then applied markups to allow for scrap, handling, factory overhead, and a "manufacturer markup" to account for per unit research and development, selling expenses, administrative expenses, and profit. This yielded an estimate of the manufacturer selling price. Details on the derivation of the manufacturer selling prices and discussion of manufacturer markups are in Chapter 5. These designs and their MSPs are subsequently inputted into the LCC customer choice model. For each EL and within each design line, the LCC model uses a Monte Carlo analysis and criteria described in TSD chapter 8 to select a subset of all the potential designs options (and associated MSPs). This subset is meant to represent those designs that would actually be shipped in the market under various standard levels. DOE inputted into the GRIM the weighted average cost of the designs selected by the LCC model and scaled those MPCs to other selected capacities in each design line's KVA range.

Tables 12.4-8 through 12.4-21 show the average production cost estimates used in the GRIM for each design line at each efficiency level.

Table 12.4-8 Manufacturer Production Cost Breakdown ($2011) for Design Line 1

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$185.83	$1,008.65	$73.26	$52.82	$1,320.57	$170.76	1.25	$1,864.15
EL 1	$196.95	$1,134.14	$82.85	$58.91	$1,472.86	$186.04	1.25	$2,073.62
EL 2	$166.21	$1,288.11	$96.40	$64.61	$1,615.33	$192.51	1.25	$2,259.81
EL 3	$160.18	$1,293.47	$97.07	$64.61	$1,615.33	$192.51	1.25	$2,259.81
EL 4	$163.51	$1,347.78	$101.28	$67.19	$1,679.77	$204.38	1.25	$2,355.18
EL 5	$144.41	$1,520.82	$115.89	$74.21	$1,855.33	$216.06	1.25	$2,589.24
EL 6	$155.73	$1,830.32	$140.20	$88.59	$2,214.84	$249.14	1.25	$3,079.98
EL 7	$155.73	$1,830.32	$140.20	$88.59	$2,214.84	$249.14	1.25	$3,079.98

Table 12.4-9 Manufacturer Production Cost Breakdown ($2011) for Design Line 2

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$124.67	$642.87	$46.44	$33.92	$847.89	$104.23	1.25	$1,190.16
EL 1	$134.63	$722.12	$52.38	$37.88	$947.01	$114.81	1.25	$1,327.28
EL 2	$128.69	$751.67	$54.99	$38.97	$974.33	$119.64	1.25	$1,367.46
EL 3	$91.20	$814.51	$61.51	$40.30	$1,007.52	$123.37	1.25	$1,413.62
EL 4	$93.02	$849.73	$64.26	$41.96	$1,048.96	$132.39	1.25	$1,476.69
EL 5	$90.78	$995.73	$76.03	$48.44	$1,210.98	$153.31	1.25	$1,705.37
EL 6	$90.35	$1,112.01	$85.35	$53.65	$1,341.36	$175.78	1.25	$1,896.43
EL 7	$89.56	$1,483.58	$115.10	$70.34	$1,758.59	$146.13	1.25	$2,380.91

Table 12.4-10 Manufacturer Production Cost Breakdown ($2011) for Design Line 3

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$410.79	$4,149.80	$315.55	$203.17	$5,079.32	$618.81	1.25	$7,122.66
EL 1	$299.86	$4,776.94	$370.16	$226.96	$5,673.92	$645.45	1.25	$7,899.21
EL 2	$301.87	$5,038.65	$391.02	$238.81	$5,970.35	$639.34	1.25	$8,262.12
EL 3	$447.89	$5,283.82	$404.79	$255.69	$6,392.19	$655.57	1.25	$8,809.69
EL 4	$306.33	$5,496.13	$427.44	$259.58	$6,489.47	$664.44	1.25	$8,942.40
EL 5	$300.62	$5,865.54	$457.22	$275.97	$6,899.35	$698.99	1.25	$9,497.92
EL 6	$303.94	$7,193.39	$563.31	$335.86	$8,396.50	$842.18	1.25	$11,548.35
EL 7	$319.87	$9,222.14	$724.98	$427.79	$10,694.78	$1,070.08	1.25	$14,706.07

Table 12.4-11 Manufacturer Production Cost Breakdown ($2011) for Design Line 4

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$327.69	$2,828.64	$213.18	$140.40	$3,509.91	$564.16	1.25	$5,092.59
EL 1	$347.06	$3,048.93	$230.03	$151.08	$3,777.10	$579.26	1.25	$5,445.45
EL 2	$364.95	$3,371.07	$255.09	$166.30	$4,157.41	$604.29	1.25	$5,952.12
EL 3	$280.54	$3,446.10	$264.47	$166.30	$4,157.41	$604.29	1.25	$5,952.12
EL 4	$200.82	$3,522.41	$273.76	$166.54	$4,163.54	$604.06	1.25	$5,959.49
EL 5	$222.83	$3,549.50	$275.05	$168.64	$4,216.01	$614.92	1.25	$6,038.67
EL 6	$234.91	$4,156.61	$323.13	$196.44	$4,911.10	$717.00	1.25	$7,035.12
EL 7	$230.23	$6,089.76	$477.97	$283.25	$7,081.21	$753.89	1.25	$9,793.87

Table 12.4-12 Manufacturer Production Cost Breakdown ($2011) for Design Line 5

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$1,668.71	$13,200.38	$989.28	$660.77	$16,519.15	$2,247.55	1.25	$23,458.37
EL 1	$1,821.53	$15,128.74	$1,137.44	$753.65	$18,841.36	$2,303.29	1.25	$26,430.81
EL 2	$1,808.95	$15,431.05	$1,162.13	$766.76	$19,168.88	$2,345.28	1.25	$26,892.70
EL 3	$1,843.15	$16,608.72	$1,254.97	$821.12	$20,527.97	$2,456.47	1.25	$28,730.54
EL 4	$1,859.19	$17,205.29	$1,302.06	$848.61	$21,215.14	$2,538.09	1.25	$29,691.53
EL 5	$1,912.52	$19,209.53	$1,460.26	$940.93	$23,523.24	$2,782.40	1.25	$32,882.05
EL 6	$2,040.69	$32,839.68	$2,545.55	$1,559.41	$38,985.33	$2,989.89	1.25	$52,469.02
EL 7	$2,040.69	$32,839.68	$2,545.55	$1,559.41	$38,985.33	$2,989.89	1.25	$52,469.02

Table 12.4-13 Manufacturer Production Cost Breakdown ($2011) for Design Line 6

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$221.50	$396.63	$22.87	$26.71	$667.71	$37.16	1.25	$881.08
EL 1	$221.85	$404.68	$23.50	$27.08	$677.12	$37.38	1.25	$893.12
EL 2	$171.94	$480.54	$31.57	$28.50	$712.55	$40.20	1.25	$940.95
EL 3	$183.68	$536.11	$35.54	$31.47	$786.80	$43.47	1.25	$1,037.84
EL 4	$181.28	$684.96	$47.55	$38.07	$951.85	$43.51	1.25	$1,244.20
EL 5	$179.63	$715.88	$50.08	$39.40	$984.99	$46.19	1.25	$1,288.98
EL 6	$172.63	$837.41	$60.09	$44.59	$1,114.72	$55.11	1.25	$1,462.28
EL 7	$172.90	$1,274.48	$95.04	$64.27	$1,606.69	$87.53	1.25	$2,117.78

Table 12.4-14 Manufacturer Production Cost Breakdown ($2011) for Design Line 7

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$371.73	$1,078.13	$71.38	$63.39	$1,584.63	$131.15	1.25	$2,144.71
EL 1	$462.30	$1,344.75	$89.09	$79.01	$1,975.14	$117.39	1.25	$2,615.67
EL 2	$468.00	$1,339.68	$88.45	$79.01	$1,975.14	$117.39	1.25	$2,615.67
EL 3	$419.42	$1,382.87	$93.85	$79.01	$1,975.14	$117.39	1.25	$2,615.67
EL 4	$329.35	$1,484.94	$105.62	$80.00	$1,999.90	$119.63	1.25	$2,649.42
EL 5	$304.22	$1,667.42	$121.22	$87.20	$2,180.07	$115.93	1.25	$2,869.99
EL 6	$297.94	$1,807.92	$132.72	$93.27	$2,331.85	$129.68	1.25	$3,076.91
EL 7	$284.58	$2,744.01	$208.14	$134.86	$3,371.59	$207.21	1.25	$4,473.50

Table 12.4-15 Manufacturer Production Cost Breakdown ($2011) for Design Line 8

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$644.47	$2,729.41	$192.57	$148.60	$3,715.06	$276.92	1.25	$4,989.97
EL 1	$805.45	$2,946.67	$203.52	$164.82	$4,120.45	$294.44	1.25	$5,518.61
EL 2	$773.04	$3,447.92	$244.91	$186.08	$4,651.95	$324.00	1.25	$6,219.93
EL 3	$856.27	$4,028.47	$288.03	$215.53	$5,388.30	$350.22	1.25	$7,173.15
EL 4	$851.41	$4,619.88	$335.53	$241.95	$6,048.77	$370.54	1.25	$8,024.14
EL 5	$821.29	$5,149.34	$379.10	$264.57	$6,614.29	$356.94	1.25	$8,714.03
EL 6	$719.26	$5,239.24	$390.37	$264.54	$6,613.40	$356.88	1.25	$8,712.86
EL 7	$651.66	$8,956.38	$690.44	$429.10	$10,727.59	$530.85	1.25	$14,073.04

Table 12.4-16 Manufacturer Production Cost Breakdown ($2011) for Design Line 9

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$1,756.20	$4,581.52	$296.27	$276.42	$6,910.40	$386.26	1.25	$9,120.83
EL 1	$1,716.25	$4,679.51	$305.71	$279.23	$6,980.70	$386.49	1.25	$9,208.99
EL 2	$1,705.13	$4,961.69	$328.73	$291.48	$7,287.03	$389.99	1.25	$9,596.28
EL 3	$1,629.32	$5,640.27	$386.05	$318.99	$7,974.63	$417.90	1.25	$10,490.67
EL 4	$1,184.02	$6,380.29	$463.06	$334.47	$8,361.85	$473.75	1.25	$11,044.50
EL 5	$1,076.52	$6,798.05	$500.78	$348.97	$8,724.33	$506.12	1.25	$11,538.05
EL 6	$1,036.03	$8,958.79	$675.26	$444.59	$11,114.67	$672.50	1.25	$14,733.96
EL 7	$1,036.03	$8,958.79	$675.26	$444.59	$11,114.67	$672.50	1.25	$14,733.96

Table 12.4-17 Manufacturer Production Cost Breakdown ($2011) for Design Line 10

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$3,139.96	$15,742.83	$1,133.83	$834.03	$20,850.64	$1,351.13	1.25	$27,752.22
EL 1	$3,053.53	$15,960.31	$1,154.68	$840.36	$21,008.88	$1,344.47	1.25	$27,941.69
EL 2	$2,997.40	$17,344.34	$1,267.65	$900.39	$22,509.78	$1,513.07	1.25	$30,028.57
EL 3	$2,831.68	$20,742.52	$1,546.13	$1,046.68	$26,167.02	$1,774.37	1.25	$34,926.74
EL 4	$2,579.69	$25,694.62	$1,952.38	$1,259.45	$31,486.14	$2,049.31	1.25	$41,919.31
EL 5	$2,538.12	$27,821.04	$2,124.16	$1,353.47	$33,836.79	$2,221.47	1.25	$45,072.83
EL 6	$2,320.33	$32,670.64	$2,520.84	$1,562.99	$39,074.79	$2,588.02	1.25	$52,078.52
EL 7	$2,320.33	$32,670.64	$2,520.84	$1,562.99	$39,074.79	$2,588.02	1.25	$52,078.52

Table 12.4-18 Manufacturer Production Cost Breakdown ($2011) for Design Line 11

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$2,246.16	$7,294.14	$493.68	$418.08	$10,452.06	$540.58	1.25	$13,740.80
EL 1	$2,326.95	$7,772.70	$528.74	$442.85	$11,071.24	$563.59	1.25	$14,543.54
EL 2	$2,298.84	$8,597.61	$595.86	$478.85	$11,971.15	$643.74	1.25	$15,768.62
EL 3	$2,445.65	$9,259.37	$642.92	$514.50	$12,862.44	$637.75	1.25	$16,875.24
EL 4	$2,200.74	$9,623.58	$681.86	$521.09	$13,027.26	$634.76	1.25	$17,077.53
EL 5	$2,094.07	$10,861.51	$785.16	$572.53	$14,313.27	$727.93	1.25	$18,801.50
EL 6	$1,947.03	$13,605.51	$1,010.56	$690.13	$17,253.23	$909.33	1.25	$22,703.19
EL 7	$1,947.03	$13,605.51	$1,010.56	$690.13	$17,253.23	$909.33	1.25	$22,703.19

Table 12.4-19 Manufacturer Production Cost Breakdown ($2011) for Design Line 12

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$3,447.63	$20,472.49	$1,499.89	$1,059.17	$26,479.18	$1,666.97	1.25	$35,182.69
EL 1	$3,499.66	$21,554.30	$1,584.36	$1,109.93	$27,748.25	$1,631.23	1.25	$36,724.35
EL 2	$3,481.31	$23,163.47	$1,713.83	$1,181.61	$29,540.21	$1,681.79	1.25	$39,027.50
EL 3	$3,649.82	$26,167.23	$1,947.39	$1,323.52	$33,087.95	$2,018.95	1.25	$43,883.63
EL 4	$3,330.93	$27,818.49	$2,092.24	$1,385.07	$34,626.73	$2,184.80	1.25	$46,014.40
EL 5	$2,863.09	$30,374.01	$2,315.40	$1,481.35	$37,033.85	$2,345.07	1.25	$49,223.66
EL 6	$2,874.77	$34,221.12	$2,622.70	$1,654.94	$41,373.53	$2,703.23	1.25	$55,095.96
EL 7	$2,741.49	$40,916.95	$3,163.70	$1,950.92	$48,773.06	$3,242.73	1.25	$65,019.74

Table 12.4-20 Manufacturer Production Cost Breakdown ($2011) for Design Line 13A

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$3,561.01	$8,534.01	$540.28	$526.47	$13,161.77	$734.97	1.25	$17,370.93
EL 1	$3,426.87	$8,971.18	$580.62	$540.78	$13,519.44	$766.94	1.25	$17,857.98
EL 2	$3,544.69	$9,595.94	$625.89	$573.60	$14,340.12	$791.00	1.25	$18,913.90
EL 3	$3,791.47	$10,820.37	$713.97	$638.58	$15,964.38	$876.46	1.25	$21,051.06
EL 4	$3,252.93	$12,524.69	$871.86	$693.73	$17,343.21	$872.83	1.25	$22,770.06
EL 5	$3,192.24	$13,581.46	$958.83	$738.86	$18,471.38	$943.28	1.25	$24,268.33
EL 6	$2,758.89	$18,565.27	$1,374.87	$945.79	$23,644.82	$1,291.78	1.25	$31,170.75
EL 7	$2,758.89	$18,565.27	$1,374.87	$945.79	$23,644.82	$1,291.78	1.25	$31,170.75

Table 12.4-21 Manufacturer Production Cost Breakdown ($2011) for Design Line 13B

EL	Labor	Materials	Overhead	Depreciation	MPC	Shipping	Markup	MSP
Baseline	$4,174.29	$26,399.26	$1,944.97	$1,354.94	$33,873.45	$2,420.49	1.25	$45,367.43
EL 1	$3,887.76	$27,129.03	$2,014.81	$1,376.32	$34,407.92	$2,512.39	1.25	$46,150.39
EL 2	$4,217.87	$30,412.80	$2,264.31	$1,537.29	$38,432.28	$2,532.58	1.25	$51,206.07
EL 3	$4,617.64	$35,162.33	$2,628.28	$1,767.01	$44,175.27	$2,877.82	1.25	$58,816.37
EL 4	$4,712.67	$40,401.65	$3,043.63	$2,006.58	$50,164.52	$2,887.32	1.25	$66,314.80
EL 5	$4,783.93	$45,787.74	$3,471.66	$2,251.81	$56,295.14	$3,263.41	1.25	$74,448.19
EL 6	$3,814.98	$46,649.03	$3,579.32	$2,251.81	$56,295.14	$3,263.41	1.25	$74,448.19
EL 7	$3,814.98	$46,649.03	$3,579.32	$2,251.81	$56,295.14	$3,263.41	1.25	$74,448.19

12.4.8 Conversion Costs

New and amended energy conservation standards will cause manufacturers to incur conversion costs to bring their production facilities and product designs into compliance. For the MIA, DOE classified these conversion costs into two major groups: (1) capital conversion costs and (2) product conversion costs. Capital conversion costs are investments in property, plant, and equipment necessary to adapt or change existing production facilities such that new product designs can be fabricated and assembled. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make product designs comply with the new or amended energy conservation standard.

12.4.8.1 Liquid Immersed Distribution Transformers

The liquid-immersed industry has evolved to be inherently flexible due to variation in customer purchasing criteria and wide fluctuations in critical materials prices, which represent the most significant fraction of product cost. Additionally, as the Department understands it, there is substantial excess production capacity for silicon steel transformers currently due to the recent economic downturn. Some manufacturers reported during interviews that shipments were down 25%-50% from their pre-recession peak. However, as discussed below, the production process for amorphous core transformers is much different and requires mostly new capital equipment. As such, currently the industry has very limited capacity for producing amorphous core distribution transformers and that capacity is concentrated among a few of the more sophisticated manufacturers in the industry.

12.4.8.1.1 Capital Conversion Expenditures

Through interviews, DOE determined that two key factors will influence the extent of investment liquid-immersed distribution transformer manufacturers make in response to energy conservation standards:

- the grade of core steel that manufacturers would most likely use to meet the standard;
- the change in core mass required to meet the standard for a given steel grade.

These two factors, which vary with the stringency of the standard, shape manufacturers' response to amended energy conservation standards. The most cost-effective core steels and the equipment necessary to process those steels affect manufacturers' sourcing decisions, investments in production equipment, and selections of core designs. In light of these two considerations, DOE used a multi-step process to estimate capital conversion costs for liquid immersed transformers. First, it developed base-case and standards-case forecasts for core steel usage by steel grade and quantity. These forecasts provided an estimate of the change in core steel demand for each steel grade at each TSL. Second, based on forecasted changes in steel use, the Department estimated the conversion costs for the entire industry to adapt to the change in standard at each TSL. Third, DOE analyzed potential manufacturer responses to the changes in steel grades and in core masses. The methodology, sources of data and assumptions, and calculation flow are shown below in Figure 12.4-1.

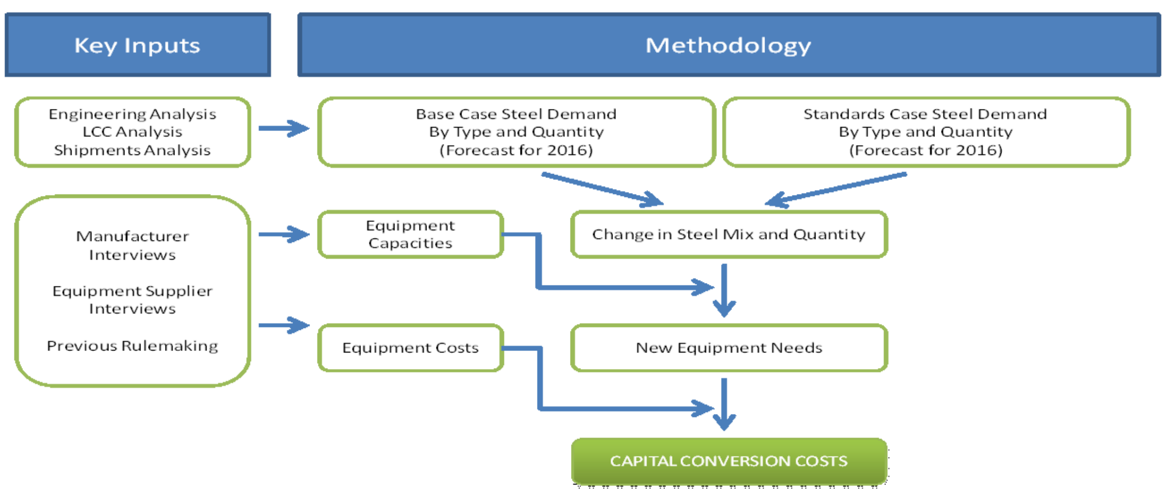

Figure 12.4-2 Capital Conversion Cost Methodology for Liquid Immersed Distribution Transformers

As shown by the figure above, to estimate conversion costs, DOE first needed an understanding of the steel grades used by manufacturers in the base case. Based on the LCC consumer choice model, DOE identified the most likely core design choices at each TSL. Using the engineering analysis, DOE determined the design parameters (e.g., core weight) for those design choices. Combining the core weights with industry shipments developed in the NIA, DOE projected future core steel needs by steel grade at each TSL. By comparing steel usage in the base case to that in the standards case, the department estimated change in core steel mix triggered by each TSL. In the liquid immersed superclass the transition to amorphous core steel is the most important variable in determining capital conversion costs because the production process is entirely different from that used for silicon steel.

It is important to note that the LCC consumer choice model assumes no availability constraints on amorphous steel, the core steel option which the engineering analysis generally found to be the most cost-effective at efficiency levels 1 or 2 and above, depending on the design line for most liquid immersed design lines. The engineering and LCC analyses also hold the relative prices of amorphous and silicon steels fixed, regardless of demand, which creates a 'toggle' effect between the steels, in which at a given EL for a given DL, all or most demand swings to one steel type, a prospect that may not occur depending on how changes in demand of certain steel types cause steel suppliers to alter pricing schemes. By presuming unlimited availability at the prices assumed in the engineering analysis, it is no surprise that the steel forecast heavily favors amorphous steel usage at TSL 3 and above for the liquid immersed superclass.

Next, DOE determined what investment would be required at each TSL, given the change in core steel demand estimated for each TSL. DOE used data gathered from interviews with core steel suppliers, core manufacturers, distribution transformer manufacturers, equipment suppliers and industry experts, as well as information gathered during the 2007 rulemaking to estimate equipment costs. Based on the gathered information, DOE assumed an amorphous production line with 1,200 tons of annual capacity would cost $950,000 to build. This figure includes costs associated with an annealing oven, core cutting machine, lacing tables and other miscellaneous equipment.

In general, where manufacturers must use amorphous materials in substantially larger quantities than the base case, conversion costs escalate quickly because all new production equipment is necessary, as opposed to just adding incremental capacity to augment existing production. For the liquid immersed superclass, when conventional steels, or even ZDMH and H-O, can be used to meet the standard, incremental increases in production equipment are driven by the need to use thinner steels or produce larger cores to achieve higher efficiencies.

Manufacturers could elect to source amorphous cores rather than produce them in-house. Many do this currently for the relatively small number of amorphous transformers they sell currently. During the manufacturer interviews, many manufacturers indicated that production of cores is an important part of the value chain and they would likely choose, in the long-run, to continue to produce them in-house rather than source them. A few of the larger manufacturers have already begun limited production of amorphous cores, as have some smaller Canadian manufacturers. Consequently, DOE believes most U.S. manufacturers would likely convert their facilities to produce the required number of amorphous cores at each TSL. As such, for the MIA, the Department modeled the scenario in which manufacturers would convert their facilities for in-house production of amorphous cores at the capacity necessary to meet the demand estimated at each of the TSLs by the LCC selection model. The LCC shows a migration to much higher volumes of amorphous core steel at every TSL for the liquid-immersed superclass.

Based on the engineering analysis, the LCC, and the estimated capital costs necessary for an amorphous transformer production line, DOE estimates the conversion costs for liquid-immersed transformers presented in Table 12.4-22 below.

Table 12.4-22 Summary of Liquid-Immersed Distribution Transformer Conversion Capital Expenditures

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Total Capital Conversion Costs ($M)	26.3	64.9	67.6	98.5	100.4	105.6	128.2

In terms of timing, DOE models all conversion costs occurring in the time period between the announcement year of the standard and the effective date of the amended energy conservation standard. However, this may be an aggressive scenario in terms of timeline. In interviews, manufacturers expressed strong reservations about the availability of amorphous steel and stability of pricing under regulatory scenarios that triggered substantial increases in demand. Tight supply of amorphous could lead to higher prices and undercut the material's relative cost-advantage over conventional steels. This is one reason manufacturers may take a gradual approach to facility conversion at efficiency levels where conventional steels, while not currently forecast to be cost competitive with amorphous steel, could become so if amorphous prices increase in relative terms. As a result, the MIA may overstate the negative cash-flow impacts of the conversion costs on industry during the period leading up to the effective date of the standard. DOE therefore considers its estimates of capital conversion costs to be conservative, and most likely so at TSL 1 through TSL 3.

12.4.8.1.1.1 Uncertainty Associated with Amorphous Demand

During interviews, manufacturers discussed several reasons why transformer production with amorphous material causes severe concerns:

- The possible difficulty of access to the technology and manufacturing know-how;
- The possible lack of availability of amorphous-core material at quantities necessary to meet industry demand;
- The high level of capital equipment investment required (and the stranding of existing assets, particularly core-cutting equipment and annealing furnaces); and
- The increased complexity associated with material processing and handling.

The Department recognizes that the manufacturing process for amorphous core transformers is significantly different from that for silicon steel transformers. As such, all TSLs would render obsolete some portion of the liquid-immersed manufacturing equipment, primarily the core-cutting equipment and the annealing furnaces. Simply put, the more rapidly and substantially amorphous steel use penetrates the market, the greater the industry's stranded silicon steel production assets will be. For example, the partial conversion to amorphous technology at TSL 1 would strand approximately $3.7 million in conventional steel core steel production equipment. If the highest (max tech) TSLs are selected for each superclass, DOE estimates that the industry would have $40.8 million in stranded assets.

As mentioned above, all TSLs would likely trigger liquid-immersed transformer manufacturers to evaluate (though not force) whether to tool for amorphous technology, attempt to purchase assembled amorphous cores, or exit the industry. At TSL 1, manufacturers could choose to operate parallel processes for conventional steel and amorphous steel since only partial conversion to amorphous is expected in the LCC consumer choice model, although this would make for complex operations within the same plant and would be especially burdensome for small manufacturers. At TSL 1, some manufacturers would likely to choose to maintain a focus on silicon steel. Additionally, a few manufacturers indicated that those who choose to produce amorphous cores themselves would face a critical decision about whether or not to relocate outside of the U.S., since much of their existing equipment would become obsolete anyway.

For those TSLs that can only be met with design options utilizing amorphous cores, industry conversion costs are easily estimated because, regardless of any assumptions about material availability or relative steel prices, manufacturers must either convert their facilities to produce amorphous, source amorphous cores, or exit the market. Since DOE is evaluating the scenario in which manufacturers convert their facilities, rather than source their cores, there is less uncertainty about total industry conversion costs. Based on DOE's projections, TSLs 4 through 7 fall into this category because only amorphous designs can meet the efficiency levels represented by these levels. No option to continue conventional steel production exists.

For TSLs 1, 2, and 3, however, the dynamics of the core steel market introduce a great deal of uncertainty about potential manufacturer responses to standards. For example, the LCC analysis predicts that even at TSL1, the market will migrate substantially to amorphous for most liquid-immersed design lines. At the same time, while TSL 1 is most cost-effectively met by amorphous cores designs (hence its popularity in the LCC consumer choice model), it can also be met with other steels (albeit at a higher production cost). This is a critical point because during interviews, many manufacturers expressed doubt that amorphous supply could meet such substantial increases in demand. As a consequence, several transformer manufacturers expect that excess demand will drive up amorphous steel prices.

Therefore, at these TSLs, the extent to which manufacturers convert their facilities to manufacture more amorphous cores depends on their assessment of two core steel market dynamics. First, what are the prospects for the availability of amorphous steel? If manufacturers doubt that the supply of amorphous steel can match the market demand at these TSLs, then there will be at least some need for conventional steels, even though these steels are not cost-competitive designs at the prices assumed in the engineering analysis. The second major consideration depends on the first: to what extent would tight supply of amorphous steel increase its price and therefore make conventional steel once again cost competitive?

Manufacturer views on these two considerations will drive their response to standards at TSL 1, 2, or 3. Each manufacturer's response, in the context of their base case market position and production capabilities, will determine the timing and level of conversion costs the industry ultimately incurs as a result of standards. Consequently, manufacturers could incur a range of conversion costs, depending upon how they elect to approach the market.

12.4.8.1.2 Product Conversion Expenses

Product conversion expenses include engineering, prototyping, testing, and marketing expenses incurred by a manufacturer as it prepares to come into compliance with a standard. The Department assumed that product conversion expenses for liquid-immersed transformer manufacturers will require total additional expenses equivalent to 1 year of the industry's R&D budget for EL 1, and 2 years of the industry's R&D budget for ELs 2-7. DOE believes this is reasonable because the industry has very little experience producing amorphous transformers and will have to prepare to produce at volumes several times more than current volumes. Product conversion expenses are summarized in Table 12.4-23.

Table 12.4-23 Summary of Product Conversion Expenditures for Liquid Immersed Industry

	TSL 1	TSL 2	TSL 3	TSL 4	TSL5	TSL 6	TSL 7
Product Conversion Expenditures ($M)	27.6	46.8	57.5	93.7	93.7	93.7	93.7

DOE's estimates of the product and capital conversion costs for each representative design line can be found in Tables 12.4-24 through 12.4-28 below.

Table 12.4-24 Product and Capital Conversion Costs for Design Line 1 by TSL

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Capital Conversion Costs ($M)	4.15	4.15	4.15	18.75	18.55	20.15	29.43
Product Conversion Costs ($M)	9.82	9.82	9.82	19.64	19.64	19.64	19.64
Total Conversion Costs ($M)	13.97	13.97	13.97	38.39	38.19	39.79	49.07

Table 12.4-25 Product and Capital Conversion Costs for Design Line 2 by TSL

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Capital Conversion Costs ($M)	0.00	38.70	38.70	40.10	42.69	43.69	55.46
Product Conversion Costs ($M)	0.00	19.24	19.24	38.48	38.48	38.48	38.48
Total Conversion Costs ($M)	0.00	57.94	57.94	78.58	81.17	82.17	93.94

Table 12.4-26 Product and Capital Conversion Costs for Design Line 3 by TSL

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Capital Conversion Costs ($M)	0.30	0.30	0.50	0.80	0.70	0.80	1.50
Product Conversion Costs ($M)	0.36	0.36	0.71	0.71	0.71	0.71	0.71
Total Conversion Costs ($M)	0.66	0.66	1.21	1.51	1.41	1.51	2.21

Table 12.4-27 Product and Capital Conversion Costs for Design Line 4 by TSL

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Capital Conversion Costs ($M)	1.30	1.30	1.30	15.16	14.96	14.96	18.05
Product Conversion Costs ($M)	7.05	7.05	7.05	14.11	14.11	14.11	14.11
Total Conversion Costs ($M)	8.35	8.35	8.35	29.27	29.07	29.07	32.16

Table 12.4-28 Product and Capital Conversion Costs for Design Line 5 by TSL

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Capital Conversion Costs ($M)	20.55	20.45	22.94	23.64	23.54	26.03	23.74
Product Conversion Costs ($M)	10.36	10.36	20.71	20.71	20.71	20.71	20.71
Total Conversion Costs ($M)	30.91	30.81	43.65	44.35	44.25	46.74	44.45

12.4.8.2 Dry Type Transformers

The low-voltage dry-type and medium-voltage dry-type industries primarily rely on stacked core technologies. In large part, the medium-voltage dry-type market is standardized on mitered cores while the low-voltage market typically uses butt lap designs.

12.4.8.2.1 Capital Conversion Expenditures

DOE pursued two different methodologies for estimating conversion costs. First, DOE used an industry feedback approach. The Department interviewed manufacturers and industry experts about the capital conversion costs for design lines at increasing efficiency levels, aggregated the conversion cost feedback, and market-share weighted the feedback to determine likely industry capital conversion costs. Results of this approach can be found in Table 12.4-29 and Table 12.4-30.

Table 12.4-29 Summary of Low Voltage Dry Type Distribution Transformer Capital Conversion Expenditures (Aggregated Feedback Methodology)

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
Total Capital Conversion Costs ($M)	5.1	7.4	11.4	23.8	23.8	23.8

Table 12.4-30 Summary of Medium Voltage Dry Type Distribution Transformer Capital Conversion Expenditures (Aggregated Feedback Methodology)

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Total Capital Conversion Costs ($M)	2.6	4.0	7.5	10.9	11.1

Second, DOE performed a bottoms-up analysis of conversion costs based on core steel selections forecasted by the LCC and production equipment costs. DOE used a three-step process to estimate capital conversion costs for dry-type transformers. In the first step, the Department developed base-case and standards-case forecasts for core steel usage using the LCC consumer choice model. The LCC provided a distribution of likely design choices. Based on that distribution of design choices, DOE determined the most likely steel selections and identified a set of representative core design parameters (e.g., core stack heights and lamination thicknesses). In the second step, based on the forecasted change in steel use and transformer core design, DOE determined the changes in production equipment necessary to produce the new mix of distribution transformer designs. The modeling of the production process and the equipment required was based on data gathered through interviews with core steel manufacturers, core manufacturers, distribution transformer manufacturers, equipment suppliers and industry experts, as well as information gathered during the 2007 rulemaking, In the third step, DOE estimated the capital outlays at each TSL for the industry based on the additional production equipment required. For equipment costs, DOE again relied on data gathered during manufacturer and equipment supplier interviews, as well as data used in the 2007 rulemaking.

For the purposes of modeling conversion costs, DOE assumed that transformers built with silicon steels would use stacked core designs. A representative core cutting machine is projected to cost $0.75 million installed for the low-voltage, dry type industry. A representative core cutting and mitering machine is projected to cost $2.7 million for the medium-voltage dry type industry.

For low-voltage and medium-voltage distribution transformers using amorphous steel, DOE assumed that transformers would be built using wound core designs. Very few domestic dry-type manufacturers use wound core designs today. Dry-type manufacturing facilities would need to substantially retool to produce wound core products. Based on data gathered from interviews with core steel suppliers, core manufacturers, distribution transformer manufacturers, equipment suppliers and industry experts, DOE estimated that an amorphous production line with 1,200 tons of annual capacity would cost $950,000 to build. This production line cost was applied to calculate capital conversion costs for TSLs when the LCC analysis indicated the dry type market would convert to amorphous steel.

In step one of the bottoms-up conversion cost analysis above, there were some adjustments made to the core steels selected for design line 7 and design line 12 at TSL 1, TSL 2, and TSL 3 based on unanimous feedback from low-voltage dry-type and medium-voltage dry-type manufacturers. Manufacturers were concerned that LCC results were not representative of the most likely selection of steels used under those scenarios. As noted previously, the LCC consumer choice model assumes no availability constraints on core steels and does not account for potential stranded assets. For design line 7 and design line 12, the LCC tended to select higher grades of steel even when the efficiency levels could be achieved with lower grades of steel that manufacturers are more easily able to source. For those two design lines, the Department used the aggregated feedback from manufacturers to determine the core steel mix in place of the LCC result.

The results of DOE's bottoms-up conversion cost analysis can be found in Table 12.4-33and Table 12.4-34.

Table 12.4-31 Summary of Capital Conversion Expenditures for the Low-Voltage Dry-Type Industry (Bottoms-up Calculation Methodology)

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
Total Capital Conversion Costs ($M)	0.3	7.8	11.8	28.9	30.8	45.5

Table 12.4-32 Summary of Capital Conversion Expenditures for the Medium-Voltage Dry-Type Industry (Bottoms-up Calculation Methodology)

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Total Capital Conversion Costs ($M)	0.5	1.2	3.0	3.0	13.9

The bottoms-up analysis allowed DOE to validate the capital conversion costs values submitted by distribution transformer manufacturers. DOE applied the aggregated capital conversion cost values found in Table 12.4-29 and Table 12.4-30 to the GRIM. These numbers take into account manufacturers' understanding of the most likely design options, material availability, and capital expenditure requirements in the standards case.

12.4.8.2.2 Product Conversion Expenses

In the low-voltage and medium-voltage dry-type market, DOE aggregated estimates of product conversion costs from manufacturers that were gathered during interviews and scaled those estimates to represent the market share of those not interviewed. DOE's estimates of the product and capital conversion costs for each representative design line can be found in Tables 12.4-29 through 12.4-30 below.

Table 12.4-33 Summary of Product Conversion Expenditures for the Low-Voltage Dry-Type Industry

	TSL 1	TSL 2	TSL 3	TSL 4	TSL5	TSL6
Capital Conversion Costs ($M)	5.11	7.35	11.40	23.75	23.75	23.75
Product Conversion Costs ($M)	2.90	3.76	5.00	8.00	8.00	8.00
Total Conversion Costs	8.01	11.11	16.40	31.75	31.75	31.75

Table 12.4-34 Summary of Product Conversion Expenditures for the Medium Voltage Dry Type Industry

	TSL 1	TSL 2	TSL 3	TSL 4	TSL5
Capital Conversion Costs ($M)	2.60	4.00	7.50	10.90	11.10
Product Conversion Costs ($M)	1.00	2.96	4.70	4.70	8.00
Total Conversion Costs	3.60	6.96	12.20	15.60	19.10

12.4.9 Markup Scenarios

DOE used several standards case markup scenarios to represent the uncertainty about the impacts of amended energy conservation standards on prices and profitability. In the base case, DOE used the same baseline markups calculated in the engineering analysis for all product design lines. 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 markup scenario, and (2) a preservation of operating profit markup scenario. These scenarios lead to different markup values, which, when applied to the inputted MPCs, result in varying revenue and cash flow impacts.

12.4.9.1 Preservation of Gross Margin Percentage Markup 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. Based on publicly available financial information for manufacturers of distribution transformers and comments from manufacturer interviews, DOE assumed the non-production cost markup—which includes SG&A expenses; research and development expenses; interest; and profit—to be 1.25 for distribution transformers. Because this markup scenario assumes that manufacturers would be able to maintain their gross margin percentage markups as production costs increase in response to an energy conservation standard, it represents a high bound to industry profitability under an energy conservation standard.

12.4.9.2 Preservation of Operating Profit Markup 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 standard is the same as in the base 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 base case operating profit. The implicit assumption behind this markup scenario is that the industry can only maintain its operating profit in absolute dollars after the standard. Therefore, operating margin in percentage terms is squeezed (reduced) between the base case and standards case. DOE adjusted the manufacturer markups in the GRIM at each TSL to yield approximately the same earnings before interest and taxes in the standards case in the year after the compliance date of the amended standards as in the base case. This markup scenario represents a low bound to industry profitability under an energy conservation standard.

12.5 INDUSTRY FINANCIAL IMPACTS

Using the inputs and scenarios described in the previous sections, the GRIM estimated indicators of financial impacts on the distribution transformer industry. The following sections detail additional inputs and assumptions for distribution transformers. 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.

12.5.1 Impacts on Industry Net Present Value

The INPV measures the industry value and is used in the MIA to compare the economic impacts of different TSLs 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 distribution transformers GRIM estimates cash flows from 2011 to 2045. This timeframe models both the short-term impacts on the industry from the announcement of the standard until the compliance date (2012 until an estimated compliance date of January 2016) and a long-term assessment over the 30-year analysis period used in the NIA (2016 – 2045).

In the MIA, DOE compares the INPV of the base case (no amended energy conservation standards) to that of each TSL in the standards case. The difference between the base case and a standards case INPV is an estimate of the economic impacts that implementing that particular TSL would have on the industry. For the distribution transformer industry, DOE examined the two markup scenarios described above, the preservation of gross margin percentage markup scenario and the preservation of operating profit markup scenario, for each superclass. Tables 12.5-1 through 12.5-6 provide the INPV estimates for the three superclasses in the distribution transformers industry.

Table 12.5-1 Changes in Industry Net Present Value for Liquid-immersed Distribution Transformers - Preservation of Operating Profit Markup Scenario

	Units	Base Case	Trial Standard Level						
			1	2	3	4	5	6	7
INPV	2011 $ M	625.1	585.5	532.1	523.8	461.0	451.2	427.5	297.9
Change in INPV	2011 $ M	-	(39.6)	(92.9)	(101.2)	(164.0)	(173.8)	(197.6)	(327.2)
	%	-	(6.3)	(14.9)	(16.2)	(26.2)	(27.8)	(31.6)	(52.3)

Table 12.5-2 Changes in Industry Net Present Value for Liquid-immersed Distribution Transformers - Preservation of Gross Margin Percentage Markup Scenario

	Units	Base Case	Trial Standard Level						
			1	2	3	4	5	6	7
INPV	2011 $ M	625.1	614.7	583.4	577.5	551.6	537.1	547.6	673.0
Change in INPV	2011 $ M	-	(10.4)	(41.7)	(47.6)	(73.5)	(88.0)	(77.5)	48.0
	%	-	(1.7)	(6.7)	(7.6)	(11.8)	(14.1)	(12.4)	7.7

Table 12.5-3 Changes in Industry Net Present Value for Low-Voltage Dry-Type Distribution Transformers - Preservation of Operating Profit Markup Scenario

	Units	Base Case	Trial Standard Level					
			1	2	3	4	5	6
INPV	2011$ M	219.5	202.7	199.9	192.8	173.4	164.2	136.4
Change in INPV	2011$ M	-	(16.8)	(19.6)	(26.7)	(46.1)	(55.3)	(83.1)
	%	-	(7.7)	(8.9)	(12.2)	(21.0)	(25.2)	(37.9)

Table 12.5-4 Changes in Industry Net Present Value for Low-Voltage Dry-Type Distribution Transformers - Preservation of Gross Margin Percentage Markup Scenario

	Units	Base Case	Trial Standard Level					
			1	2	3	4	5	6
INPV	2011$ M	219.5	236.4	234.6	239.6	250.4	263.4	321.5
Change in INPV	2011$ M	-	16.9	15.0	20.1	30.9	43.9	101.9
	%	-	7.7	6.8	9.1	14.1	20.0	46.4

Table 12.5-5 Changes in Industry Net Present Value for Medium-Voltage Dry-Type Distribution Transformers - Preservation of Operating Profit Markup Scenario

	Units	Base Case	Trial Standard Level				
			1	2	3	4	5
INPV	2011$ M	91.0	87.1	84.5	79.7	77.1	71.0
Change in INPV	2011$ M	-	(3.8)	(6.5)	(11.3)	(13.9)	(20.0)
	%	-	(4.2)	(7.1)	(12.4)	(15.3)	(21.9)

Table 12.5-6 Changes in Industry Net Present Value for Medium-Voltage Dry-Type Distribution Transformers - Preservation of Gross Margin Percentage Markup Scenario

	Units	Base Case	Trial Standard Level				
			1	2	3	4	5
INPV	2011$ M	91.0	89.1	90.0	95.1	92.5	114.1
Change in INPV	2011$ M	-	(1.9)	(0.9)	4.1	1.5	23.1
	%	-	(2.0)	(1.0)	4.5	1.7	25.4

12.5.2 Impacts on Annual Cash Flow

While INPV is useful for evaluating the long-term effects of amended energy conservation standards, short-term changes in cash flow are also important indicators of the industry's financial situation. For example, a large investment over one or two years could strain the industry's access to capital. Consequently, 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. To get an idea of the behavior of annual free cash flows, Figures 12.5-1 through 12.5-6 below present the annual free cash flows from 2011 through 2045 for the base case and different TSLs in the standards case.

Annual cash flows are discounted to the base year, 2011. Between 2011 and the 2016 compliance date of the amended energy conservation standard, cash flows are driven by the level of conversion costs and the proportion of these investments spent every year. After the standard 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. 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 would have enjoyed longer use 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 either be positively or negatively affected in the year the standard takes effect.

In the years following the compliance date of the standard, the impact on cash flow depends on the operating revenue. In the preservation of gross margin percentage scenario, the manufacture markup is held constant to yield the same gross margin percentage in the standards case at each TSL as in the base case in the year after the standard takes effect. The implicit assumption is that manufacturers can freely pass on and mark up higher cost units. The result under this scenario is that operating cash flow increases (in absolute terms) as revenue increases. At the highest TSLs where MPCs dramatically increase, this scenario drives large increases in operating cash flow relative to the base case. The larger the production cost increase, then, the more likely it is that the increase in operating cash flow after the standard takes affect will outweigh the initial conversion costs..

Under the preservation of operating profit scenario, cash flow decreases at each TSL in the standards case compared to the base case because, since the absolute dollar amount of the gross margin does not change despite an increase in sales and cost of goods sold, the gross margin percentage is reduced. Figures 12.5-1 through 12.5-6 present the annual free cash flows for each superclass of distribution transformers.

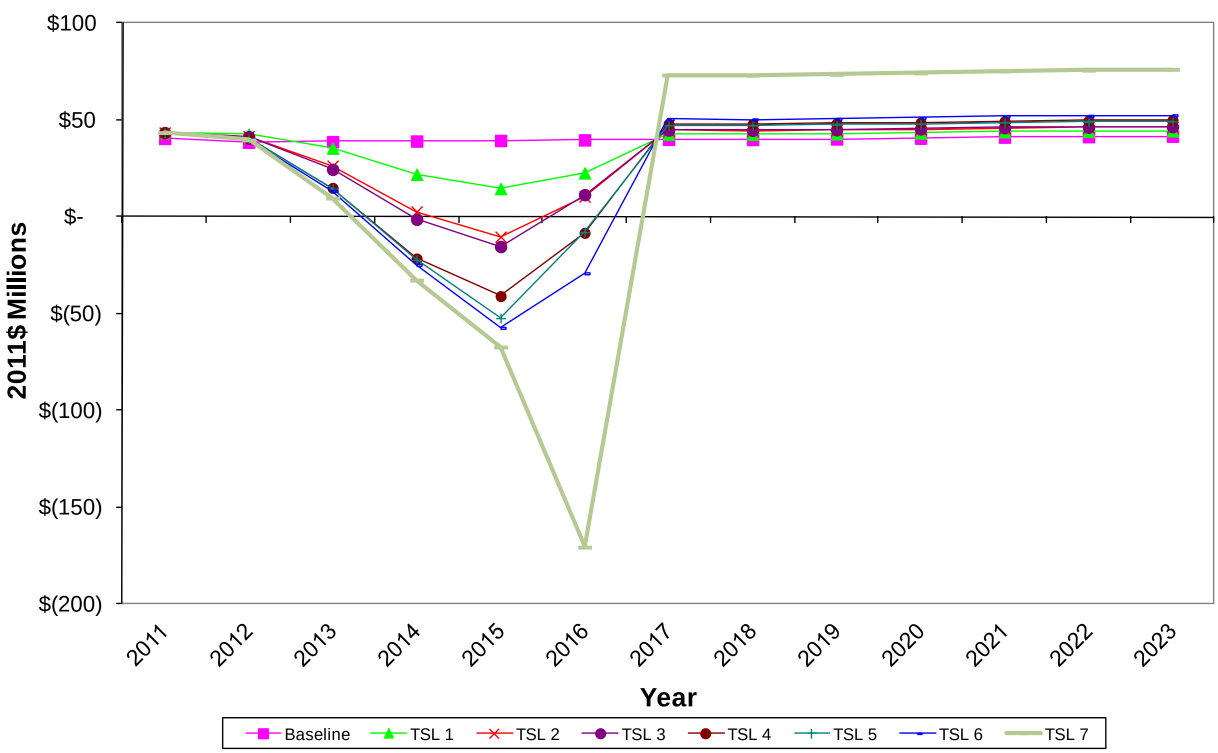

Figure 12.5-1 Annual Industry Free Cash Flows for Liquid-immersed Distribution Transformers - Preservation of Gross Margin Percentage Markup Scenario

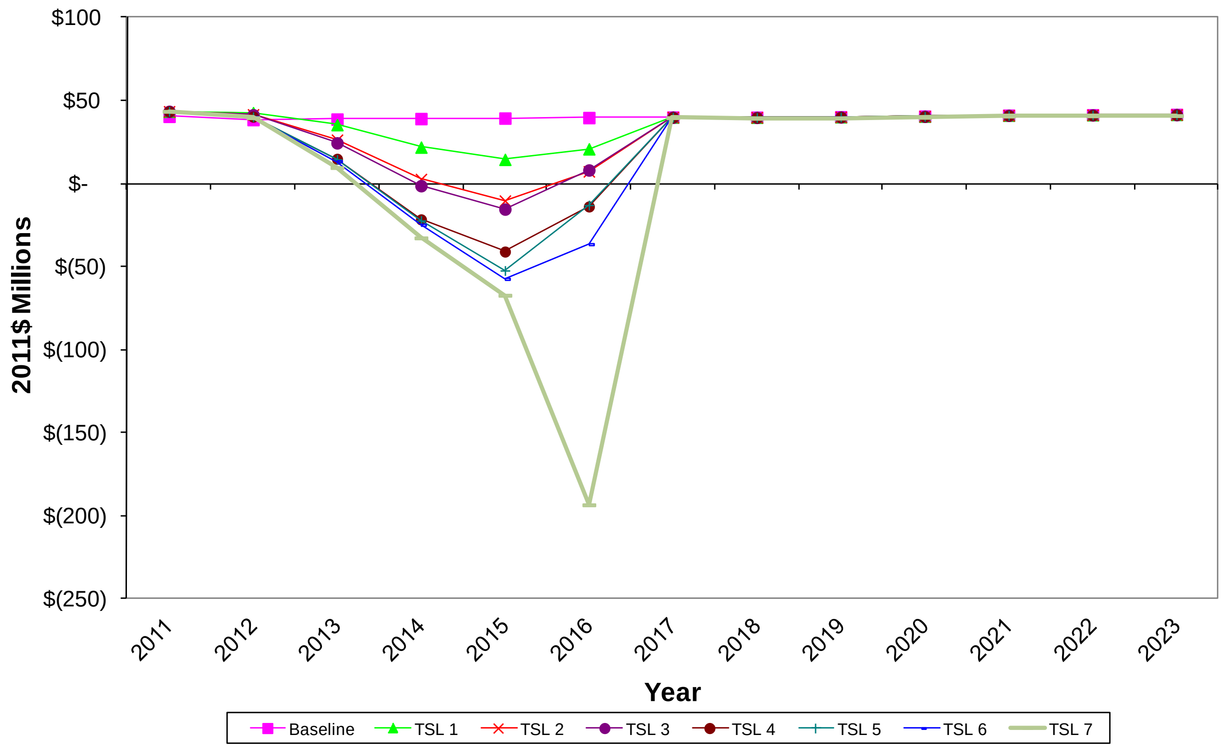

Figure 12.5-2 Annual Industry Free Cash Flows for Liquid-immersed Distribution Transformers - Preservation of Operating Profit Markup Scenario

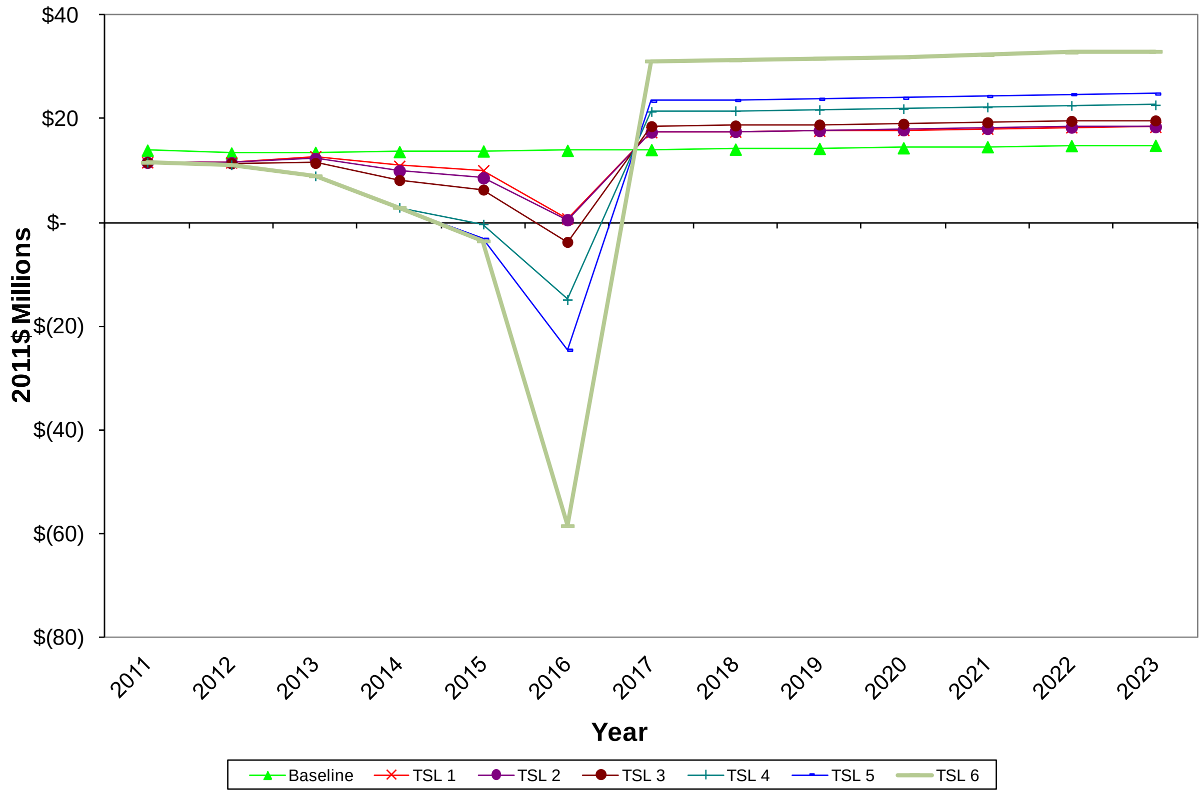

Figure 12.5-3 Annual Industry Free Cash Flows for Low-Voltage Dry-Type Distribution Transformers - Preservation of Gross Margin Percentage Markup Scenario

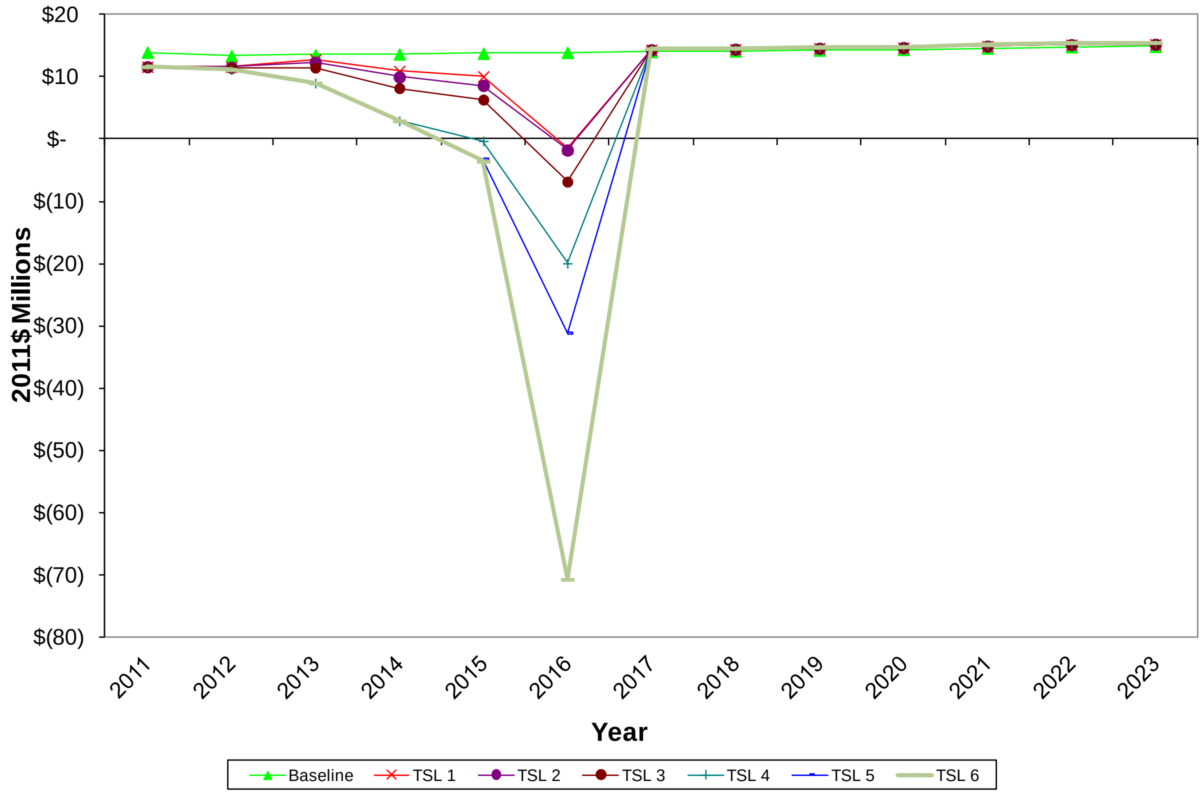

Figure 12.5-4 Annual Industry Free Cash Flows for Low-Voltage Dry-Type Distribution Transformers - Preservation of Operating Profit Markup Scenario

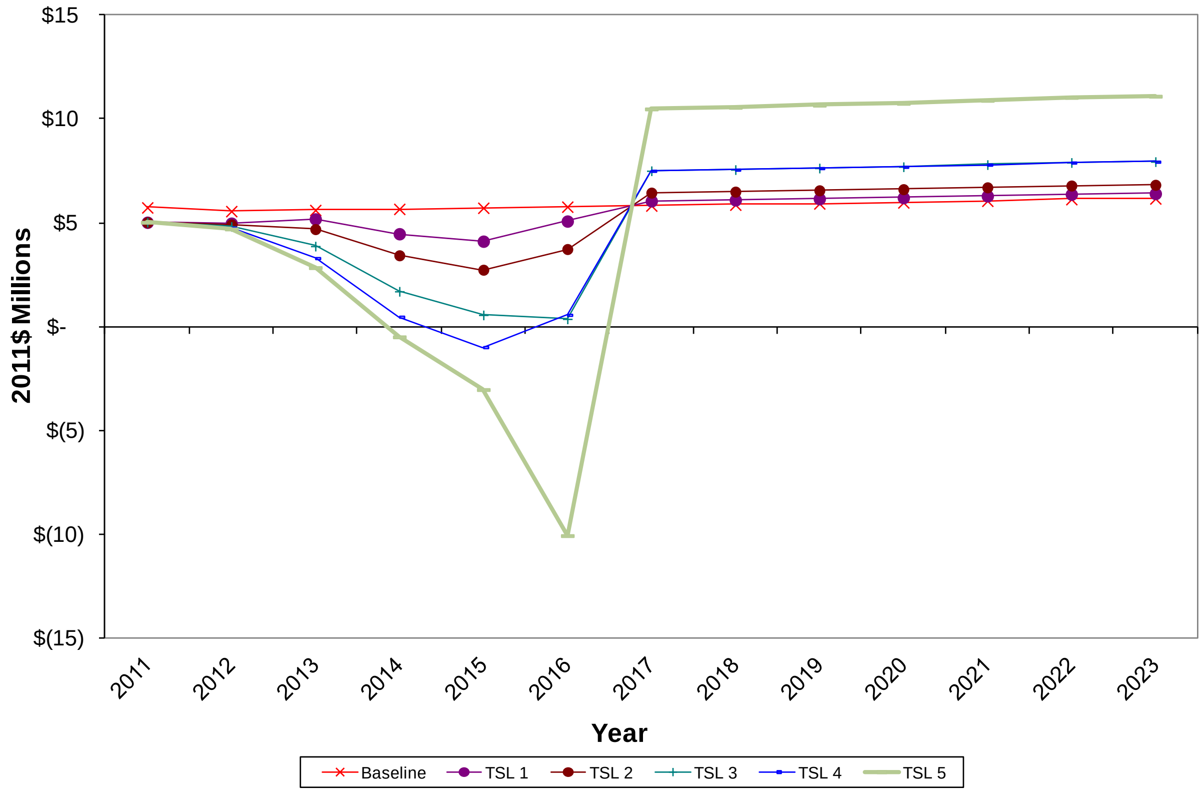

Figure 12.5-5 Annual Industry Free Cash Flows for Medium-Voltage Dry-Type Distribution Transformers - Preservation of Gross Margin Percentage Markup Scenario

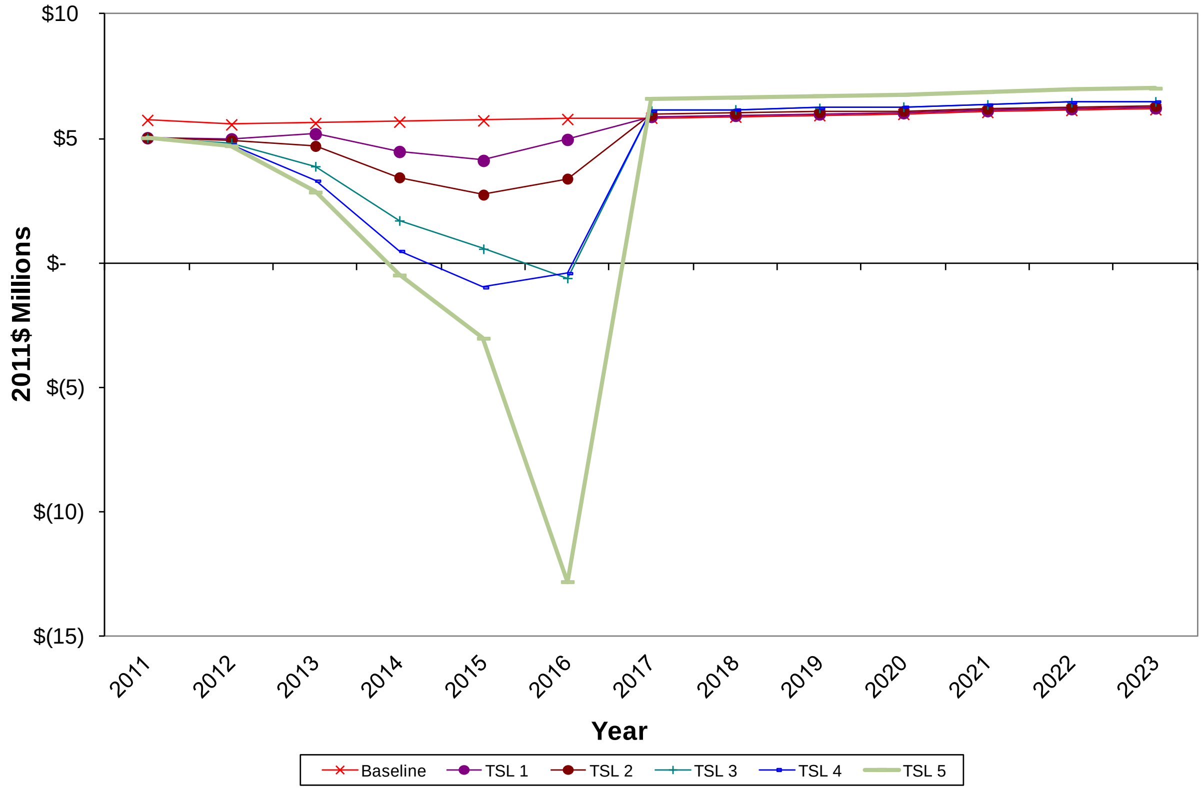

Figure 12.5-6 Annual Industry Free Cash Flows for Medium-Voltage Dry-Type Distribution Transformers - Preservation of Operating Profit Markup Scenario

12.6 IMPACTS ON MANUFACTURER SUBGROUPS

As described in Section 12.2.3 above, DOE identified one subgroup of distribution transformer manufacturers: small manufacturers. The results of this subgroup analysis are described below.

12.6.1 Impacts on Small Business Manufacturers

12.6.1.1 Description and Estimated Number of Small Entities Regulated

DOE conducted a more focused inquiry of the companies that could be small business manufacturers of products covered by this rulemaking. During its market survey, DOE used all available public information to identify potential small manufacturers. DOE's research involved industry trade association membership directories (including NEMA), UL qualification directories, individual company websites, and market research tools (e.g., Dun and Bradstreet reports) to create a list of every company that manufactures or sells distribution transformers covered by this rulemaking. DOE also asked stakeholders and industry representatives if they were aware of any other small manufacturers during manufacturer interviews and at previous

DOE public meetings. DOE contacted select companies on its list, as necessary, to determine whether they met the SBA's definition of a small business manufacturer of covered distribution transformers. DOE screened out companies that did not offer products covered by this rulemaking, did not meet the definition of a "small business," or are foreign owned and operated.

DOE initially identified at least 63 potential manufacturers of distribution transformers sold in the U.S. DOE reviewed information on these 63 potential manufacturers and determined 33 were large manufacturers, were foreign owned, and/or operated or did not manufacture transformers covered by this rulemaking. DOE then attempted to contact the remaining companies that were potential small business manufacturers. Though many companies were unresponsive, DOE was able to determine that approximately 30 meet the SBA's definition of a small business and likely manufacture transformers covered by this rulemaking.

Before issuing this NOPR, DOE attempted to contact the small business manufacturers of distribution transformers it had identified. Three of the small businesses consented to being interviewed during the MIA interviews, and DOE received feedback from additional small businesses through surveys, phone interviews, follow-up discussions, and consensus meetings. DOE also obtained information about small business impacts while interviewing large manufacturers.

Liquid Immersed.

Six major manufacturers supply more than 80 percent of the market for liquid-immersed transformers. None of the major manufacturers of distribution transformers covered in this rulemaking are considered to be small businesses. The vast majority of shipments are manufactured domestically. Electric utilities compose the customer base and typically buy on first-cost. Many small manufacturers position themselves towards the higher end of the market or in particular product niches, such as network transformers or harmonic mitigating transformers, but, in general, competition is based on price after a given unit's specs are prescribed by a customer.

Low-Voltage Dry-Type.

Four major manufacturers supply more than 80 percent of the market for low-voltage dry-type transformers. None of the major low-voltage dry-type manufacturers of distribution transformers covered in this rulemaking are small businesses. The customer base rarely purchases on efficiency and is very first-cost conscious, which, in turn, places a premium on economies of scale in manufacturing. DOE estimates approximately 80 percent of the market is served by imports, mostly from Canada and Mexico. Many of the small businesses that compete in the low-voltage dry-type market produce specialized transformers that are exempted from standards. Roughly 50 percent of the market by revenue is exempted from DOE standards. This market is much more fragmented than the one serving DOE-covered low-voltage dry-type transformers.

In the DOE-covered low-voltage dry-type market, low-volume manufacturers typically do not compete directly with large manufacturers using business models similar to those of their bigger rivals because scale disadvantages in purchasing and production are usually too great a barrier in this portion of the market.. The exceptions to this rule are those companies that also compete in the medium-voltage market and, to some extent, are able to leverage that experience and production economies. More typically, low-volume manufacturers have focused their operations on one or two parts of the value chain—rather than all of it—and trained their sights on market segments outside of the high-volume baseline efficiency market.

In terms of operations, some small firms focus on the engineering and design of transformers and source the production of the cores or even the whole transformer, while other small firms focus on just production and rebrand for companies that offer broader solutions through their own sales and distribution networks.

In terms of market focus, many small firms simply compete entirely in the DOE-exempted markets. DOE did not attempt to contact companies operating entirely in this very fragmented market. Of those that do compete in the DOE-covered market, a few small businesses reported a focus on the high-end of the market, often selling NEMA Premium or better transformers as retrofit opportunities. Others focus on particular applications or other niches, like data centers, and become well-versed in the unique needs of a particular customer base.

Medium-Voltage Dry-Type.

The medium-voltage dry-type transformer market is relatively consolidated with one large company holding a substantial share of the market. Electric utilities and industrial users make up most of the customer base and typically buy on first-cost or features other than efficiency. DOE estimates that at least 75 percent of production occurs domestically. Several manufacturers also compete in the power transformer market. Like the low-voltage dry-type industry, most small business manufacturers often produce transformers exempted from DOE standards. DOE estimates 10 percent of the market is exempt from standards.

12.6.1.2 Comparison Between Large and Small Entities

Small distribution transformer manufacturers differ from large manufacturers in several ways that affect the extent to which they would be impacted by the proposed standard. Characteristics of small manufacturers include: less access to capital, lower production volumes, fewer engineering resources, less technical expertise, and lack of purchasing power for high performance materials.

In general, small manufacturers have less access to capital which would be needed to cover the conversion costs associated with a new standard. Investors have less of an incentive to make loans to small businesses because they are typically riskier than loans made to large businesses. Therefore, a manufacturer that has more than 750 employees, or that is owned by a parent company with more than 750 employees, would be able to obtain funds (either by itself or through its parent company) more easily than would a small manufacturer.

Small manufacturers also have lower production volumes than large manufacturers. Therefore, their conversion costs would need to be spread across fewer units and the reduction in profit/unit would be significantly greater for them than for a large manufacturer. Although the same equipment would need to be purchased by both large and small manufacturers in order to produce transformers that meet DOE standards, the return on investment for a small manufacturer would be lower because it does not sell as many units.

Since they have fewer employees, smaller companies are also more likely to have smaller engineering teams. If new standards require a lot of product development time to implement, the engineering staff of a small manufacturer may not be large enough to address higher efficiency standards while performing routine work. In addition, if investments need to be made for conversion costs, smaller companies are less likely to have enough capital left over to invest in the necessary additional engineering resources.

Generally, smaller companies may also have less experience and expertise in working with newer technologies. Large companies with better access to capital and bigger R&D budgets have more resources to invest in the development of new technologies and product lines. In the case of transformers, large manufacturers have exhibited greater technical expertise and experience in working with amorphous core and symmetric core technologies, both of which allow higher efficiency levels to be achieved. During manufacturer interviews, one manufacturer stated that there should be no major impact on small manufacturers if standards can be met with stacked core technology, but if alternative core constructions are needed, then small manufacturers may be negatively impacted because they lack the resources to pursue or develop such technologies.

Furthermore, small manufacturers can be at a disadvantage due to their lack of purchasing power for high performance materials, especially considering the limited availability of high grade steels in the production of distribution transformers. During manufacturer interviews, one manufacturer stated that it was unable to even obtain a quote for amorphous steel, let alone purchase the material.

12.6.1.3 Description and Estimate of Compliance Requirements

Liquid Immersed. Based on interviews with manufacturers in the liquid-immersed market, DOE does not believe small manufacturers will face significant capital conversion costs at the levels proposed in today's rulemaking. DOE expects small manufacturers of liquid-immersed distribution transformers to continue to produce silicon steel cores, rather than invest in amorphous technology. While silicon steel designs capable of achieving TSL 1 would get larger, and thus reduce throughput, most manufacturers said the industry in general has substantial excess capacity due to the recent economic downturn. Therefore, DOE believes TSL 1 would not require the typical small manufacturer to invest in additional capital equipment. However, small manufacturers may incur some engineering and product design costs associated with re-optimizing their production processes around new baseline products. DOE estimates TSL 1 would require industry production development costs of only one-half of one year's annual industry R&D expenses, as the levels do not require any changes in technology or steel types. Because these costs are relatively fixed per manufacturer, these one-time costs impact smaller manufacturers disproportionately compared to larger manufacturers. Table 12.6-1 below illustrates this effect by comparing the conversion costs to the annual R&D expenses of a typical small company and a typical large company.

Table 12.6-1 Estimated Product Conversion Costs as a Percentage of Annual R&D Expense

	Product Conversion Cost	Product Conversion Cost as a Percentage of Annual R&D Expense
Typical Large Manufacturer	$1.4 M	20%
Typical Small Manufacturer	$1.4 M	222%

While the costs disproportionately impact small manufactures, the standard levels, as stated above, do not require small manufacturers to invest in entirely different production processes nor do they require steels or core construction techniques with which these manufacturers are not familiar. A range of design options would still be available.

Low-Voltage Dry-Type. For the low-voltage dry-type market, at TSL 1, the level proposed in today's notice, DOE estimates capital conversion costs of $0.75 million and product conversion costs of $0.2 million for a typical small and large manufacturer, based on manufacturer interviews. Because of the largely fixed nature of these one-time conversion expenditures that distribution transformer manufacturers would incur as a result of standards, small manufacturers who choose to maintain in-house production will likely be disproportionately impacted compared to large manufacturers. As Table 12.6-2 indicates, small manufacturers face a greater relative hurdle in complying with standards should they opt to continue to maintain core production in-house.

Table 12.6-2 Estimated Capital and Product Conversion Costs as a Percentage of Annual Capital Expenditures and R&D Expense

	Capital Conversion Cost as a Percentage of Annual Capital Expenditures	Product Conversion Cost as a Percentage of Annual R&D Expense	Total Conversion Cost as a Percentage of Annual EBIT
Large Manufacturer	40%	11%	17%
Small Manufacturer	152%	49%	77%

As demonstrated in the table above, the investments required to meet TSL 1 disproportionately impact small businesses. However, DOE's capital conversion costs estimates in the table above assume that small businesses are currently producing their cores in-house and will choose to do so in the future, rather than source them from third-party core manufactures who often have significant cost advantages through bulk steel purchasing power and greater production efficiencies due to higher volumes. As such, many small businesses DOE interviewed already source a large percentage of their cores and many indicated they expected such a strategy would be the low-cost option under higher standards.

Compared to higher TSLs, TSL 1 provides many more design paths for small manufacturers to comply. DOE's engineering analysis indicates manufacturers can continue to use the low-capital butt-lap core designs, meaning investment in mitering capability is not necessary to comply. Manufacturers can use higher-quality grain oriented steels in butt-lap designs to meet these proposed efficiency levels, source some or all cores, or invest in mitering capability. DOE notes that roughly half of the small business low-voltage dry-type manufacturers DOE interviewed already have mitering capability. For all of the reasons discussed, DOE believes the capital expenditures it assumed for small businesses are likely conservative and that small businesses have a variety of technical and strategic paths to continue to compete in the market at TSL 1.

Medium-Voltage Dry-Type. Based on its engineering analysis and interviews, DOE expects relatively minor capital expenditures for the industry to meet TSL 2. DOE understands that the market is already standardized on step-lap mitering, so manufacturers will not need to make major investments for more advanced core construction. Furthermore, TSL 2 does not require a change to much thinner steels such as M3 or HO. The industry can use M4 and H1, thicker steels with which it has much more experience and which are easier to employ in the stacked-core production process that dominates the medium-voltage market. However, some investment will be required to maintain capacity as some manufacturers will likely migrate to more M4 and H1 steel from the slightly thicker M5, which is also common.. Additionally, design options at TSL 2 typically have larger cores, also slowing throughput. Therefore, some manufacturers may need to invest in additional production equipment. Alternatively, depending on each company's availability capacity, manufacturers could employ additional production shifts, rather than invest in additional capacity.

For the medium-voltage dry-type market, at TSL 2, the level proposed in today's notice, DOE estimates capital conversion costs of $1.0 million and product conversion costs of $0.2 million for a typical small and large manufacturer that would be needed to expand mitering capacity to meet TSL 2. Table 12.6-3 illustrates the relative impacts on small and large manufacturers.

Table 12.6-3 Estimated Capital and Product Conversion Costs as a Percentage of Annual Capital Expenditures and R&D Expense

	Capital Conversion Cost as a Percentage of Annual Capital Expenditures	Product Conversion Cost as a Percentage of Annual R&D Expense	Total Conversion Cost as a Percentage of Annual EBIT
Large Manufacturer	43%	7%	14%
Small Manufacturer	327%	65%	124%

Summary of Compliance Impacts. The compliance impacts on small businesses are discussed above for low-voltage dry-type, medium-voltage dry-type, and liquid-filled distribution transformer manufacturers. Although the conversion costs required can be considered substantial for all companies, the impacts could be relatively greater for a typical small manufacturer because of much lower production volumes and the relatively fixed nature of the R&D and capital investments required.

DOE seeks comment on the potential impacts of amended standards on small distribution transformer manufacturers.

12.7 OTHER IMPACTS

12.7.1 Employment

Liquid Immersed. Based on interviews and industry research, DOE estimates that there are roughly 5,000 employees associated with DOE-covered liquid immersed distribution transformer production and some three-quarters of these workers are located domestically. DOE does not expect large changes in domestic employment to occur due to today's proposed standard. Manufacturers generally agreed that amorphous production is more labor-intensive and would require greater labor expenditures than traditional steel core production. So long as domestic plants are not relocated outside the country, DOE expects moderate increases in domestic employment at TSL1 and TSL2. There could be a small drop in employment at small, domestic manufacturing firms if small manufacturers begin sourcing cores. This employment would presumably transfer to the core makers, some of whom are domestic and some of whom are foreign. There is a risk that energy conservation standards that largely require the use of amorphous steel could cause even large manufacturers who are currently producing transformers in the U.S. to evaluate offshore options. Faced with the prospect of wholesale changes to their production process, large investments and stranded assets, some manufacturers expect to strongly consider shifting production offshore at TSL 3 or TSL 4 due to the increased labor expenses associated with the production processes required to make amorphous steel cores. In summary, at TSLs 1 and 2, DOE does not expect significant impacts on employment, but at TSL 3 or higher, which would require more investment, the impact is very uncertain.

Low-Voltage Dry-Type. Based on interviews with manufacturers, DOE estimates that there are approximately 2,200 employees associated with DOE-covered low-voltage dry-type production. Approximately 75 percent of these employees are located outside of the U.S. Typically, high volume units are made in Mexico, taking advantage of lower labor rates, while custom designs are made closer to the manufacturer's customer base or R&D centers. DOE does not expect large changes in domestic employment to occur due to a standard. Most production already occurs outside the U.S. and, by and large, manufacturers agreed that most design changes necessary to meet higher energy conservation standards would increase labor expenditures, not decrease them. If, however, small manufacturers began sourcing cores instead of manufacturing them in-house, there could be a small drop in employment at these firms. This employment would presumably transfer to the core makers, some of whom are domestic and some of whom are foreign. In summary, DOE does not expect significant changes to domestic low-voltage dry-type industry employment levels as a result of the proposed standards. Higher TSLs may lead to small declines in domestic employment as more firms will be challenged with what amounts to clean-sheet redesigns. Facing the prospect of greenfield investments, these manufacturers may elect to make those investments in lower-labor cost countries or source their cores from potentially foreign manufacturers.

Medium-Voltage Dry-Type. Based on interviews with manufacturers, DOE estimates that there are approximately 1,850 employees associated with DOE-covered medium-voltage dry-type transformer production. Approximately 75 percent of these employees are located domestically. With the exception of TSLs that require amorphous cores, manufacturers agreed that most design changes necessary to meet higher energy conservation standards would increase labor expenditures, not decrease them, but current production equipment would not be stranded, mitigating any incentive to move production offshore. Corroborating this, the largest manufacturer and domestic employer in this market has indicated that the standard, as proposed in this rule, will not cause their company to reconsider production location. As such, DOE does not expect significant changes to domestic medium-voltage dry-type industry employment levels as a result of the standard proposed in this rule. For TSLs that would require amorphous cores, DOE does anticipate significant changes to domestic medium-voltage dry-type industry employment levels.

12.7.2 Production Capacity

Capacity can be viewed from two perspectives: one focused on core steel supply and one focused more broadly on transformer production (which would encompass core steel supply issues).

In terms of core steel, the issue of capacity rests largely with the liquid immersed market, which uses roughly three quarters of the core steel consumed by the entire DOE-covered distribution transformer market. It must be noted also that core steel is a global market and an active import/export market exists. Thus, surges in demand in foreign countries can constrain supply with respect to U.S. market needs. Additionally, some steel types and grades are used not only across superclasses but are also used substantially in transformers not covered by this analysis. Most notably, HO and H1, steels well-suited to high-efficiency stacked-core designs in the dry-type market, happen to be most popular in the power transformer market.

With that said, based on industry interviews, DOE expects minimal core steel capacity issues at those TSLs that do not force the entire market into amorphous steel usage. At those TSLs that are projected to move the majority of the market to amorphous steel, DOE believes there could be capacity issues associated with ramping amorphous steel production in time to meet the 1/1/2016 compliance date. This occurs at TSL 4 in the liquid immersed market, at TSL 5 in the medium-voltage dry-type market, and at TSL 4 in the low-voltage dry-type market. In aggregate, based on DOE analysis, at current steel prices, these levels portend more than a 10-fold increase in the demand of amorphous ribbon in the U.S. Because this is only supplied by one supplier, and because most of that supplier's output is currently used to meet foreign demand, which DOE has no reason to believe will subside, let alone stop growing, the department has concerns about the availability of a sufficient supply of amorphous at these high TSLs.

With respect to M2 steel, which remains cost competitive with amorphous designs at efficiencies higher than M3 is capable of, DOE understands that M2 steel has a technical engineering constraint associated with its output. A maximum of 1 pound of M2 steel can be produced for every 4 pounds of M3 or lower steel. Therefore, if there is no market for M3 steel, it is highly unlikely that M2 steel could be used to meet a significant portion of the liquid immersed market demand.

In terms of transformer production capacity, DOE understands from interviews that there is significant excess capacity in silicon steel production assets. Shipments are well off their peak from 2008. Therefore, DOE does not expect capacity problems at levels that maintain silicon steels as viable design options in the market. However, at the TSLs noted above, at which only amorphous cores would likely be competitive, transformer manufacturers would face large hurdles in changing over their entire production processes in three years, particularly in the medium dry-type market which has no experience using amorphous technology. Even under the assumption that all core steels are widely available, substantial changes in transformer efficiency standards could require the entire industry to order the same types of specialized equipment, which come with long lead times, and could only be ordered after a lengthy R&D process of engineering, testing, and prototyping.

In summary, at TSL 1, 2, and 3 for liquid immersed market, TSL 1, 2, 3, and 4 for medium-voltage dry type market, and TSL 1, 2, and 3 for the low-voltage dry type market, DOE does not expect significant impacts on capacity. However, at higher TSLs, DOE believes there is a risk of adverse impacts on capacity due to a potential near-term limitation on amorphous steel supply and, to a lesser extent, long lead times for specialized production equipment.

12.7.3 Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of recent or 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. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency. During previous stages of this rulemaking DOE identified a number of requirements in addition to amended energy conservation standards for distribution transformers.

12.7.3.1 Federal Regulations on Distribution Transformer Manufacturers

For low-voltage dry-type transformers, the Energy Policy Act of 2005 required compliance with NEMA TP-1 standards by the beginning of 2007. For liquid-immersed and medium voltage dry type transformers, DOE's 2007 energy conservation standards rulemaking required compliance by the beginning of 2010. Since the last set of energy conservation standards for distribution transformers went into effect very recently and required large capital investments and retooling, any new standards which would require additional retooling and investment would create a cumulative burden for manufacturers.

In addition to efficiency regulations, liquid-immersed distribution transformer manufacturers also need to comply with the National Energy Code (NFPA 70), which requires that indoor liquid-immersed transformers be located in separate transformer vaults and provides stipulations for fire walls, doors, ventilation, and oil containment. The impetus for this section of the National Energy Code is to prevent fires associated with flammable insulating fluids, but such requirements increase the installed cost of liquid-immersed transformers.

12.7.3.2 Foreign Regulations on Distribution Transformer Manufacturers

Manufacturers that export their products to places such as Canada, China, Mexico, or the Middle East need to comply with foreign as well as domestic regulations. The Canadian government regulates efficiency of dry-type transformers through its Canadian Standards Association (CSA) standard C802.2-00 (effective January 1, 2005). China regulates transformer efficiency through its China Compulsory Certification (CCC) program (effective May 1, 2002), which requires manufacturers of various products including transformers to obtain the CCC Mark before exporting to or selling in the Chinese market. In Mexico, liquid-immersed units are regulated through NOM-002-SEDE-2010.

12.8 CONCLUSION

The following section summarizes the impacts for the scenarios DOE believes are most likely to capture the range of impacts on distribution transformer manufacturers as a result of amended energy conservation standards. DOE also notes that while these scenarios bound the range of most plausible impacts on manufacturers, there potentially could be circumstances which cause manufacturers to experience impacts outside of this range.

Liquid Immersed.

TSL 1 represents a set of efficiency levels in which there is a diversity of electrical steels that are cost-competitive and economically feasible for all design lines. At TSL 1, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$39.6 million to -$10.4 million, corresponding to a change in INPV of -6.3 percent to -1.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 60.1 percent to $15.8 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

While TSL 1 can be met with traditional steels, including M3, in all design lines, amorphous core transformers will be incrementally more competitive on a first cost basis, likely inducing some or many manufacturers to gradually build amorphous steel transformer production capacity. Because the production process for amorphous cores is entirely separate from that of silicon steel cores, large investments in new capital, including new core cutting equipment and annealing ovens will be required. Additionally, a great deal of testing, prototyping, design and manufacturing engineering resources will be required because most manufacturers have relatively little experience, if any, with amorphous steel transformers. These capital and production conversion expenses lead to a reduction in cash flow in the years preceding the standard. In the lower-bound scenario, DOE assumes manufacturers can only maintain annual operating profit in the standards case. Therefore, these conversion investments, and manufacturers' higher working capital needs associated with more expensive transformers, drain cash flow and lead to a greater reduction in INPV when compared to the upper-bound scenario. In the upper bound scenario, DOE assumes manufacturers will be able to fully mark up and pass the higher product costs, leading to higher operating income. This higher operating income is essentially offset on a cash flow basis by the conversion costs and the increase in working capital requirements, leading to a negligible change in INPV at TSL1 in the upper-bound scenario.

TSL 2 represents EL1 for all design lines. At TSL 2, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$92.9 million to -$41.7 million, corresponding to a change in INPV of -14.9 percent to -6.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 122.7 percent to -$9 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

TSL 2 requires the same efficiency levels as TSL 1, except for DL 2, which increases from baseline to EL1. EL1, as opposed to the baseline efficiency, could induce manufacturers to build more amorphous capacity, when compared to TSL 1, because amorphous transformers become incrementally more cost competitive. Because DL2 represents the largest share of core steel usage of all design lines, this has a significant impact on investments. There are more severe impacts on industry in the lower-bound profitability scenario when these greater one-time cash outlays are coupled with slight margin pressure. In the high-profitability scenario, manufacturers are able to maintain gross margins, mitigating the adverse cash flow impacts of the increased investment in working capital that is associated with more expensive transformers.

TSL 3 represents the maximum efficiency level achievable with M3 core steel. At TSL 3, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$101.2 million to -$47.6 million, corresponding to a change in INPV of -16.2 percent to -7.6 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 135.2 percent to -$13.9 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

TSL 3 results are similar to TSL 2 results because the efficiency levels are the same except for DL3 and DL5, which each increase to EL 2 under TSL 3. The increase in stringency makes amorphous core transformers slightly more cost competitive in these DLs, likely increasing amorphous transformer capacity needs, all other things being equal, and driving more investment to meet the standards.

TSL 4 represents the maximum NPV at a 7 percent discount rate. At TSL 4, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$164 million to -$73.5 million, corresponding to a change in INPV of -26.2 percent to -11.8 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 202 percent to -$40.3 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

During interviews, manufacturers expressed differing views on whether the efficiency levels embodied in TSL 4 would shift the market away from silicon steels entirely. Because DL3 and DL5 must meet EL4 at this TSL, DOE expects the majority of the market would shift to amorphous core transformers at TSL 4 and above. Even assuming a sufficient supply of amorphous steel were available, TSL 4 and above would require a dramatic build up in amorphous core transformer production capacity. DOE believes this wholesale transition away from silicon steels could seriously disrupt the market, drive small businesses to either source their cores or exit the market, and lead even large businesses to consider moving production offshore or exiting the market altogether. The negative impacts are driven by the large conversion costs associated with new amorphous production lines and stranded assets of manufacturers' existing silicon steel transformer production capacity. If the higher first costs at TSL 4 drive more utilities to refurbish rather than replace failed transformers, a scenario many manufacturers predicted at the efficiency levels and prices embodied in TSL 4, reduced transformer sales could cause further declines in INPV.

TSL 5 represents EL 3 for all design lines. At TSL 5, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$173.8 million to -$88 million, or a change in INPV of -27.8 percent to -14.1 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 230.8 percent to -$51.7 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

TSL5 would likely shift the entire market to amorphous core transformers, leading to even greater investment needs than at TSL4, and driving the adverse impacts discussed above.

TSL 6 represents the maximum source energy savings with positive NPV at a 7 percent discount rate. At TSL 6, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$197.6 million to -$77.5 million, corresponding to a change in INPV of -31.6 percent to -12.4 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 241.5 percent to -$55.9 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

The impacts at TSL 6 are similar to those DOE expects at TSL 5, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 6 compared to TSL 5.

TSL 7 represents the maximum technologically feasible level (max tech). At TSL 7, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from -$327.2 million to $48 million, corresponding to a change in INPV of -52.3 percent to 7.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 267.2 percent to -$66 million, compared to the base-case value of $39.5 million in the year before the compliance date (2015).

The impacts at TSL 7 are similar to those DOE expects at TSL 6, except that slightly more amorphous core production capacity will be needed because TSL 7-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 7 compared to TSL 6, thereby further reducing industry value.

Low-Voltage Dry-Type.

TSL 1 represents the maximum efficiency level achievable with M6 core steel. At TSL 1, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from -$16.8 million to $16.9 million, corresponding to a change in INPV of -7.7 percent to 7.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 26.1 percent to $10.2 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL 1 provides many design paths for manufacturers to comply. DOE's engineering analysis indicates manufacturers can continue to use existing butt-lap core designs, meaning investment in mitering or wound core capability is not necessary. Manufacturers can also use higher-quality grain oriented steels in butt-lap designs to meet TSL1, source some or all cores, or invest in modified mitering capability.

TSL 2 represents NEMA premium levels. At TSL 2, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from -$19.6 million to $15 million, corresponding to a change in INPV of -8.9 percent to 6.8 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 37.4 percent to $8.6 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL2 differs from TSL1 in that DL6 and DL7 must meet EL3, up from baseline for DL 6 and up from EL2 for DL 7. These changes in standard would likely require advanced core construction techniques, including mitering or wound core designs. Much of the incremental investment needed at TSL2 is due to the increase from EL2 to EL3 in DL7, which represents more than three-quarters of the market by core weight in this superclass. This increase in stringency for DL7 drives the need for investment in mitering capacity. All major manufacturers already have mitering capability, but moving the high-volume DL7 from butt-lap to mitered cores would slow throughput and require additional capacity. A range of options are still available at TSL2 as manufacturers could use higher grade steels, mitering, or wound cores. Additionally, at TSL2, manufacturers will still be able to use M6, which is common in the current market. However, some manufacturers, usually small manufacturers, indicated during interviews that they would begin to source a greater share of their cores rather than make investments in mitering machines or wound core production lines.

TSL 3 represents the maximum efficiency achievable using butt-lap miter core manufacturing for single-phase distribution transformers and full miter core manufacturing for three-phase distribution transformers. At TSL 3, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from -$26.7 million to $20.1 million, corresponding to a change in INPV of -12.2 percent to 9.1 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 53.9 percent to $6.4 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL3 represents EL4 for DL6, DL7, and DL8. DOE's engineering analysis shows that manufacturers will be able to meet EL4 using M4 or better steels. M4, however, is a thinner steel than is currently employed, which, in combination with larger cores, will dramatically slow production throughput, requiring the industry to expand capacity to maintain current shipments. This is the reason for the increase in conversion costs. In the lower-bound profitability scenario, when DOE assumes the industry cannot fully pass on incremental costs, these investments and the higher working capital needs drain cash flow and lead to the negative impacts shown in the preservation of operating profit scenario. In the high-profitability scenario, impacts are slightly positive because DOE assumes manufacturers are able to fully recoup their conversion expenditures through higher operating cash flow.

TSL 4 represents the maximum NPV at a 7 percent discount rate. At TSL 4, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from -$46.1 million to $30.9 million, corresponding to a change in INPV of -21 percent to 14.1 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 102.1 percent to -$0.3 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

TSL 4 and higher would create significant challenges for the industry and likely disrupt the marketplace. DOE's conversion costs at TSL 4 assume the industry will entirely convert to amorphous wound core technology to meet the efficiency standards. Few manufacturers of distribution transformers in this superclass have any experience with amorphous steel or wound core technology and would face a steep learning curve. This is reflected in the large conversion costs and adverse impacts on INPV in the Preservation of Operating Profit scenario. Most manufacturers DOE interviewed expected many low-volume manufacturers to exit the DOE-covered market altogether if amorphous steel was required to meet the standard. As such, DOE believes TSL 4 could lead to greater consolidation than the industry would experience at lower TSLs.

TSL 5 represents the maximum source energy savings with positive NPV at a 7 percent discount rate. At TSL 5, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from -$55.3 million to $43.9 million, corresponding to a change in INPV of -25.2 percent to 20 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 122.6 percent to -$3.1 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

The impacts at TSL 5 are similar to those DOE expects at TSL 4, except that slightly more amorphous core production capacity will be needed because TSL 5-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 5 compared to TSL 4.

TSL 6 represents the maximum technologically feasible level (max tech). At TSL 6, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from -$83.1 million to $101.9 million, corresponding to a change in INPV of -37.9 percent to 46.4 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 125.7 percent to -$3.5 million, compared to the base-case value of $13.8 million in the year before the compliance date (2015).

The impacts at TSL 6 are similar to those DOE expects at TSL 5, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 6 compared to TSL 5.

Medium-Voltage Dry-Type.

TSL 1 represents EL1 for all design lines. At TSL 1, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from -$3.8 million to -$1.9 million, corresponding to a change in INPV of -4.2 percent to -2.0 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 28.1 percent to $4.1 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 1 represents EL1 for all MVDT design lines. At TSL 1, manufacturers have a variety of steels available to them, including M4, the most common steel in the superclass, in DL12, the largest DL by core steel usage. Additionally, the vast majority of the medium-voltage dry-type market already uses step-lap mitering technology. Therefore, DOE anticipates only moderate conversion costs for the industry, mainly associated with slower throughput due to larger cores. Some manufacturers may need to slightly expand capacity to maintain throughput and/or modify equipment to manufacture with greater precision and tighter tolerances. In general, however, conversion expenditures should be relatively minor compared to INPV. For this reason, TSL 1 yields relatively minor adverse changes to INPV in the standards case.

TSL 2 represents a set of efficiency levels in which there is a diversity of electrical steels that are cost-competitive and economically feasible for all design lines. At TSL 2, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from -$6.5 million to -$0.9 million, corresponding to a change in INPV of -7.1 percent to -1.0 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 52.1 percent to $2.7 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 2 requires EL2, rather than EL1, in DLs 10, 12, and 13B. Because M4 (as well as the commonly used H1) can still be employed to meet these levels, DOE expects similar results at TSL 2 as at TSL 1. Slightly greater conversion costs will be required as the compliant transformers will have heavier cores, all other things being equal, meaning additional capacity may be necessary depending on each manufacturer’s current capacity utilization rate. As with TSL 1, TSL 2 will not require significant changes to most production processes because the thickness of the steels will not change significantly, if at all.

TSL 3 represents the maximum NPV at a 7 percent discount rate. At TSL 3, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from -$11.3 million to $4.1 million, corresponding to a change in INPV of -12.4 percent to 4.5 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 90.1 to $0.6 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 4 represents the maximum source energy savings with positive NPV at a 7 percent discount rate. At TSL 4, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from -$13.9 million to $1.5 million, corresponding to a change in INPV of -15.3 percent to 1.7 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately -117.2 percent to -$1.0 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 3 and TSL 4 require EL2 for DL9 and DL10, but EL4 for DL11 through DL13B, which hold the majority of the volume. Several manufacturers were concerned TSL 3 would require some of the high volume design lines to use either H1,HO, or transition entirely to amorphous wound cores. Without a cost effective M-grade steel option, the industry could face severe disruption. Even assuming a sufficient supply of Hi-B steel, a major concern of some manufacturers because it is used and generally priced for the power transformer market, relatively large expenditures would be require in R&D and engineering as most manufacturers would have to move production to steels with which they have little experience. DOE estimates total conversion costs would more than double at TSL 3, relative to TSL 2. If, based on the movement of steel prices, EL4 can be met cost competitively only through the use of amorphous steel or an exotic design with little or no current place in scale manufacturing, manufacturers would face significant challenges that DOE believes would lead to consolidation and likely cause many low-volume manufacturers to exit the product line or source their cores.

TSL 5 represents the maximum technologically feasible level (max tech). At TSL 5, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from -$20 million to $23.1 million, corresponding to a change in INPV of -21.9 percent to 25.4 percent. At this proposed level, industry free cash flow is estimated to decrease by approximately 152.8 percent to -$3.0 million, compared to the base-case value of $5.7 million in the year before the compliance date (2015).

TSL 5 represents max-tech and yields results similar to, but more severe than, TSL 4 results. The entire market must convert to amorphous wound cores at TSL 5. Because the industry has no experience with wound core technology, and little, if any, experience with amorphous steel, this transition would represent a tremendous challenge for industry. Interviews suggest most manufacturers would exit the market altogether or source their cores rather than make the investments in plant and equipment and R&D required to meet these levels.

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1 NEMA – NEMA Members. Last Accessed December 30, 2010. <http://www.nema.org/about/members/ >.

2 McKinsey & Company, Inc. *Valuation: Measuring and Managing the Value of Companies*, 3rd Edition, Copeland, Koller, Murrin. New York: John Wiley & Sons, 2000.

CHAPTER 13. EMPLOYMENT IMPACT ANALYSIS

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CHAPTER 13. EMPLOYMENT IMPACT ANALYSIS

13.1 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 distribution transformers. Job increases or decreases reported in this chapter are separate from the direct distribution transformer 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. DOE separately evaluates liquid immersed (LI), medium-voltage dry-type (MVDT), and low-voltage dry-type (LVDT) transformers.

13.2 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. Since 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.

13.3 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 operating and capital costs and potential reductions in employment that increase expenditures in other goods and services. In this particular rule, the analysis assumes that any savings likely to accrue to utilities from more efficient distribution transformers will be invested.

DOE also notes that the employment impacts estimated with ImSET for the entire economy differ from the employment impacts in the distribution transformer 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.

13.4 SHORT-TERM RESULTS

The results in this section refer to impacts of distribution transformer 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 anticipates no change in operations and maintenance costs for distribution transformers. DOE presents the summary impact.

Conceptually, one can consider the impact of the rule in its first year on three aggregate sectors, the distribution transformer 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 increases the purchase price of distribution transformers; 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. The reduction in electricity demand causes a reduction in employment in that sector. Finally, based on the net impact of increased expenditures on distribution transformers 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 13.4.1 - 13.4.3 present the modeled net employment impact from the rule in 2016. Distribution transformers are imported or produced domestically; 10% of LI transformers, 25% of MVDT transformers , and 75% of LVDT transformers are imported. The net employment impact estimate is sensitive to assumptions regarding the return to the U.S. economy of money spent on imported distribution transformers. The two scenarios bounding the ranges presented in Table 13.4.1 - 13.4.3 represent situations in which none of the money spent on imported distribution transformers returns to the U.S. economy and all of the money spent on imported distribution transformers returns to the U.S. economy. The U.S. trade deficit in recent years suggests that between 50% and 75% of the money spent on imported distribution transformers is likely to return, with employment impacts falling within the ranges presented below.

Table 13.4.1 Liquid Immersed Distribution Transformers Net National Short-term Change in Employment (1000 jobs)

Trial Standard Level	2016	2020
TSL 1	-1.37 to -0.22	-1.02 to 0.18
TSL 2	-2.75 to -0.44	-2.04 to 0.36
TSL 3	-2.85 to -0.45	-2.09 to 0.39
TSL 4	-4.66 to -0.74	-3.43 to 0.63
TSL 5	-4.92 to -0.80	-3.72 to 0.55
TSL 6	-7.05 to -1.23	-5.78 to 0.24
TSL 7	-22.87 to -4.55	-21.58 to -2.65

Table 13.4.2 Medium-Voltage Dry-Type Distribution Transformers Net National Short-term Change in Employment (1000 jobs)

Trial Standard Level	2015	2020
TSL 1	-0.08 to -0.03	-0.04 to 0.01

TSL 2	-0.48 to -0.18	-0.39 to -0.09
TSL 3	-0.56 to -0.21	-0.45 to -0.09
TSL 4	-0.56 to -0.21	-0.45 to -0.09
TSL 5	-1.79 to -0.71	-1.65 to -0.54

Table 13.4.3 Low-Voltage Dry-Type Distribution Transformers Net National Short-term Change in Employment (1000 jobs)

Trial Standard Level	2016	2020
TSL 1	-0.09 to 0.22	0.63 to 0.94
TSL 2	-0.11 to 0.23	0.62 to 0.97
TSL 3	-0.19 to 0.27	0.66 to 1.13
TSL 4	-0.39 to 0.41	0.82 to 1.65
TSL 5	-0.63 to 0.46	0.59 to 1.72
TSL 6	-1.58 to 0.64	-0.26 to 2.04

For context, OMB currently assumes that the unemployment rate may decline to 6.9% in 2014 and drop further to 5.3% in 2017.[5] The unemployment rate in 2017 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.

13.5 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. Since 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 since 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. The ImSET model projections, assuming no price or wage effects until 2020, are included in the second column of Table 13.4.1 – 13.4.3.

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CHAPTER 14. UTILITY IMPACT ANALYSIS

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CHAPTER 14. UTILITY IMPACT ANALYSIS

14.1 INTRODUCTION

DOE analyzed the effects of its amended standard levels on the electric utility industry using a variant 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 *AEO* for 2011 *(AEO2011)* forecasts energy supply and demand through 2035. [1] DOE used a variant of this model, referred to as NEMS-BT,[b] to account for the impacts of transformer energy conservation standards. DOE's utility impact analysis consists of a comparison between model results for the *AEO2011* Reference Case and for cases in which standards are in place, and applies the same basic set of assumptions as the *AEO2011*. The *AEO2011* reference case corresponds to medium economic growth.

The utility impact analysis reports the changes in electric installed capacity and generation that result for each trial standard level (TSL) by plant type, as well as changes in residential and commercial electricity consumption.

NEMS-BT has several advantages that have led to its adoption as the forecasting tool in the analysis of energy conservation standards. NEMS-BT uses a set of assumptions that are well known and fairly transparent, due to the exposure and scrutiny each *AEO* receives. In addition, the comprehensiveness of NEMS-BT permits the modeling of interactions among the various energy supply and demand sectors, producing a complete picture of the effects of energy conservation standards. Perhaps most importantly, NEMS-BT can be used to estimate marginal effects, which yield a better estimate of the actual impact of energy conservation standards than considering only average effects.

14.2 METHODOLOGY

NEMS provides reference case load shapes for several end uses. The model uses predicted growth in demand for each end use to build up a projection of the total electric system load growth for each region, which it uses in turn to predict the necessary additions to capacity. DOE uses NEMS-BT to account for the implementation of energy conservation standards by decrementing the appropriate reference case load shape. For transformers all end uses were

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[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 2003*, DOE/EIA-0581(2003), March, 2003.

[b] DOE/EIA approves use of the name NEMS to describe only an official version of the model without any modification to code or data. Because this analysis entails some minor code modifications and the model is run under various policy scenarios that are variations on DOE/EIA assumptions, DOE refers to it by the name NEMS-BT (BT is DOE's Building Technologies Program, under whose aegis this work has been performed). NEMS-BT was previously called NEMS-BRS.

evenly decremented to accurately represent the effect of transformer efficiency on the overall household consumption. These decrements are also divided amongst the nine U.S. Census divisions based upon the share of energy end use consumption in each division, as given in NEMS.

DOE used the site energy savings developed in the national impact analysis (chapter 10) for each TSL as input to NEMS-BT. The magnitude of the energy decrement that would be required for NEMS-BT to produce stable results out of the range of numerical noise is larger than the highest efficiency standard under consideration. Therefore, DOE estimated results corresponding to each TSL using interpolation. DOE ran higher energy use reduction levels in NEMS-BT, representing multipliers of each TSL, and used these outputs to linearly interpolate the results to estimate actual changes in generation and capacity due to the standard.

Although the current time horizon of NEMS-BT is 2035, other parts of the energy conservation standards analysis extend through the year 2045. It is not feasible to extend the forecast period of NEMS-BT for the purposes of this analysis, nor does DOE/EIA have an approved method for extrapolation of many outputs beyond 2035. While it might seem reasonable to make simple linear extrapolations of results, in practice this is not advisable because outputs could be contradictory. An analysis of various trends sufficiently detailed to guarantee consistency is beyond the scope of this work, and, in any case, would involve a great deal of uncertainty. Therefore, all extrapolations beyond 2035 are simple replications of year 2035 results. To emphasize the extrapolated results wherever they appear, they are shaded in gray to distinguish them from actual NEMS-BT results.

14.3 RESULTS

This utility impact analysis reports NEMS-BT forecasts for residential and commercial sector electricity consumption, total electricity generation by fuel type, and installed electricity generation capacity by fuel type. Results are presented in five-year increments through 2035. Beyond 2035, an extrapolation through 2045 for each TSL represents a simple replication of the 2035 results.

The results from the *AEO2011* Reference Case are shown in Table 14.3.1.

The results for the TSLs for all three types of transformers are presented in Tables 14.3.2 through 14.3.20. There are seven TSLs for liquid immersed transformers, six TSLs for low-voltage dry-type transformers, and five TSLs for high-voltage dry-type transformers. Each table shows forecasts using interpolated results, as described in section 14.2, for total U.S. electricity generation and installed capacity.

The considered transformer TSLs reduce electricity consumption compared to the *AEO2011* Reference Case. The electricity savings predicted by the NIA Model for all transformer products range from 0.01 to 0.47 percent of total residential and commercial electricity consumption in the year 2035.

Table 14.3.1 AEO 2011 Reference Case Forecast

NEMS-BT Results: AEO 2011 Reference Case							
	2005	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**
Residential Sector Energy Consumption [1]							
Electricity Sales (TWh)[2]	1,359	1,455	1,348	1,394	1,461	1,538	1,613
Commercial Sector Energy Consumption [1]							
Electricity Sales (TWh)[2]	1,275	1,349	1,416	1,526	1,636	1,761	1,886
Total U.S. Electric Generation [3]							
Coal (TWh)	2,013	1,864	1,799	1,907	2,069	2,137	2,218
Gas (TWh)	759	1,010	999	1,000	1,000	1,148	1,283
Petroleum (TWh)	122	45	43	44	44	45	46
Nuclear (TWh)	782	803	839	877	877	877	874
Renewables (TWh)	360	414	556	608	673	703	724
Total (TWh)[4]	4,036	4,136	4,236	4,436	4,663	4,911	5,146
Installed Generating Capacity [5]							
Coal (GW)	314	322	322	323	326	329	334
Other Fossil (GW)[6]	439	471	471	470	490	530	571
Nuclear (GW)	100	101	106	110	110	110	110
Renewables (GW)	100	132	154	159	169	176	180
Total (GW)[7]	953	1,027	1,052	1,061	1,095	1,146	1,196

[1]Comparable to Table A2 of AEO2011: Energy Consumption

[2]Comparable to Table A8 of AEO2011: Electricity Sales by Sector

[3]Comparable to Table A8 of AEO2011: Electric Generators and Cogenerators

[4]Excludes "Other Gaseous Fuels" cogenerators and "Other" cogenerators

[5]Comparable to Table A9 of AEO2011: Electric Generators and Cogenerators Capability

[6]Includes "Other Gaseous Fuels" cogenerators

[7]Excludes Pumped Storage and Fuel Cells

Table 14.3.2 Liquid Immersed Transformers Trial Standard Level 1 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,919	3,096	3,297	3,496
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,907	2,068	2,137	2,218
Gas (TWh)	1,010	999	1,000	999	1,147	1,281
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	608	673	703	724
Total (TWh)	4,136	4,236	4,435	4,661	4,909	5,143
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	334
Other Fossil (GW)	471	471	470	490	530	571
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	159	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,145	1,195

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.000	0.000	-0.705	-1.393	-2.061	-2.695	-3.273	-3.586	-3.779
Total U.S. Electric Generation									
Coal (TWh)	0.122	0.245	-0.305	-0.452	-0.471	-0.486	-0.486	-0.486	-0.486
Gas (TWh)	-0.122	-0.045	-0.241	-0.593	-1.119	-1.623	-1.623	-1.623	-1.623
Petroleum (TWh)	0.000	0.000	-0.004	-0.004	-0.002	-0.008	-0.008	-0.008	-0.008
Nuclear (TWh)	0.000	0.000	-0.077	-0.075	-0.073	-0.070	-0.070	-0.070	-0.070
Renewables (TWh)	-0.001	-0.163	-0.096	-0.221	-0.255	-0.310	-0.310	-0.310	-0.310
Total (TWh)	-0.001	0.037	-0.724	-1.345	-1.920	-2.497	-2.497	-2.497	-2.497
Installed Generating Capacity									
Coal (GW)	0.000	-0.028	-0.046	-0.046	-0.045	-0.045	-0.045	-0.045	-0.045
Other Fossil (GW)	0.000	-0.025	-0.078	-0.191	-0.356	-0.478	-0.478	-0.478	-0.478
Nuclear (GW)	0.000	0.000	-0.010	-0.009	-0.009	-0.009	-0.009	-0.009	-0.009
Renewables (GW)	0.000	-0.047	-0.045	-0.066	-0.075	-0.078	-0.078	-0.078	-0.078
Total (GW)	0.000	-0.100	-0.179	-0.312	-0.484	-0.610	-0.610	-0.610	-0.610

Table 14.3.3 Liquid Immersed Transformers Trial Standard Level 2 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,918	3,094	3,295	3,494
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,906	2,068	2,137	2,217
Gas (TWh)	1,009	999	1,000	999	1,146	1,280
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	607	672	703	723
Total (TWh)	4,136	4,236	4,435	4,660	4,907	5,141
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	334
Other Fossil (GW)	471	471	469	490	530	570
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,145	1,194

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-1.41	-2.79	-4.14	-5.42	-6.59	-7.23	-7.62
Total U.S. Electric Generation									
Coal (TWh)	0.24	0.49	-0.61	-0.91	-0.95	-0.98	-0.98	-0.98	-0.98
Gas (TWh)	-0.24	-0.09	-0.48	-1.19	-2.25	-3.26	-3.26	-3.26	-3.26
Petroleum (TWh)	0.00	0.00	-0.01	-0.01	0.00	-0.02	-0.02	-0.02	-0.02
Nuclear (TWh)	0.00	0.00	-0.15	-0.15	-0.15	-0.14	-0.14	-0.14	-0.14
Renewables (TWh)	0.00	-0.33	-0.19	-0.44	-0.51	-0.62	-0.62	-0.62	-0.62
Total (TWh)	0.00	0.07	-1.45	-2.70	-3.85	-5.02	-5.02	-5.02	-5.02
Installed Generating Capacity									
Coal (GW)	0.00	-0.06	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09
Other Fossil (GW)	0.00	-0.05	-0.16	-0.38	-0.71	-0.96	-0.96	-0.96	-0.96
Nuclear (GW)	0.00	0.00	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
Renewables (GW)	0.00	-0.09	-0.09	-0.13	-0.15	-0.16	-0.16	-0.16	-0.16
Total (GW)	0.00	-0.20	-0.36	-0.63	-0.97	-1.23	-1.23	-1.23	-1.23

Table 14.3.4 Liquid Immersed Transformers Trial Standard Level 3 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,918	3,094	3,294	3,493
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,906	2,068	2,136	2,217
Gas (TWh)	1,009	999	1,000	998	1,146	1,279
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	607	672	702	723
Total (TWh)	4,136	4,236	4,435	4,660	4,907	5,140
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	334
Other Fossil (GW)	471	471	469	490	529	570
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,145	1,194

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-1.51	-3.00	-4.46	-5.87	-7.17	-7.88	-8.33
Total U.S. Electric Generation									
Coal (TWh)	0.26	0.52	-0.65	-0.97	-1.02	-1.06	-1.06	-1.06	-1.06
Gas (TWh)	-0.26	-0.10	-0.52	-1.27	-2.42	-3.53	-3.53	-3.53	-3.53
Petroleum (TWh)	0.00	0.00	-0.01	-0.01	0.00	-0.02	-0.02	-0.02	-0.02
Nuclear (TWh)	0.00	0.00	-0.17	-0.16	-0.16	-0.15	-0.15	-0.15	-0.15
Renewables (TWh)	0.00	-0.35	-0.21	-0.48	-0.55	-0.67	-0.67	-0.67	-0.67
Total (TWh)	0.00	0.08	-1.55	-2.89	-4.15	-5.43	-5.43	-5.43	-5.43
Installed Generating Capacity									
Coal (GW)	0.00	-0.06	-0.10	-0.10	-0.10	-0.10	-0.10	-0.10	-0.10
Other Fossil (GW)	0.00	-0.05	-0.17	-0.41	-0.77	-1.04	-1.04	-1.04	-1.04
Nuclear (GW)	0.00	0.00	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
Renewables (GW)	0.00	-0.10	-0.10	-0.14	-0.16	-0.17	-0.17	-0.17	-0.17
Total (GW)	0.00	-0.21	-0.38	-0.67	-1.05	-1.33	-1.33	-1.33	-1.33

Table 14.3.5 Liquid Immersed Transformers Trial Standard Level 4 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,917	3,092	3,291	3,489
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,906	2,067	2,136	2,216
Gas (TWh)	1,009	999	999	998	1,144	1,277
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	607	672	702	723
Total (TWh)	4,136	4,236	4,434	4,658	4,904	5,137
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	489	529	570
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,193

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-2.47	-4.96	-7.45	-9.90	-12.20	-13.50	-14.31
Total U.S. Electric Generation									
Coal (TWh)	0.42	0.85	-1.07	-1.61	-1.70	-1.78	-1.78	-1.78	-1.78
Gas (TWh)	-0.43	-0.16	-0.85	-2.11	-4.05	-5.96	-5.96	-5.96	-5.96
Petroleum (TWh)	0.00	0.00	-0.01	-0.02	-0.01	-0.03	-0.03	-0.03	-0.03
Nuclear (TWh)	0.00	0.00	-0.27	-0.27	-0.26	-0.26	-0.26	-0.26	-0.26
Renewables (TWh)	0.00	-0.57	-0.34	-0.79	-0.92	-1.14	-1.14	-1.14	-1.14
Total (TWh)	0.00	0.13	-2.54	-4.79	-6.94	-9.17	-9.17	-9.17	-9.17
Installed Generating Capacity									
Coal (GW)	0.00	-0.10	-0.16	-0.17	-0.16	-0.17	-0.17	-0.17	-0.17
Other Fossil (GW)	0.00	-0.09	-0.27	-0.68	-1.29	-1.75	-1.75	-1.75	-1.75
Nuclear (GW)	0.00	0.00	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03
Renewables (GW)	0.00	-0.16	-0.16	-0.23	-0.27	-0.29	-0.29	-0.29	-0.29
Total (GW)	0.00	-0.35	-0.63	-1.11	-1.75	-2.24	-2.24	-2.24	-2.24

Table 14.3.6 Liquid Immersed Transformers Trial Standard Level 5 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,917	3,092	3,291	3,489
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,906	2,067	2,136	2,216
Gas (TWh)	1,009	999	999	998	1,144	1,277
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	607	672	702	723
Total (TWh)	4,136	4,236	4,434	4,658	4,904	5,137
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	490	529	570
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,193

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-2.44	-4.90	-7.35	-9.76	-12.04	-13.31	-14.11
Total U.S. Electric Generation									
Coal (TWh)	0.42	0.84	-1.06	-1.59	-1.68	-1.76	-1.76	-1.76	-1.76
Gas (TWh)	-0.42	-0.16	-0.84	-2.08	-3.99	-5.88	-5.88	-5.88	-5.88
Petroleum (TWh)	0.00	0.00	-0.01	-0.02	-0.01	-0.03	-0.03	-0.03	-0.03
Nuclear (TWh)	0.00	0.00	-0.27	-0.26	-0.26	-0.25	-0.25	-0.25	-0.25
Renewables (TWh)	0.00	-0.56	-0.33	-0.78	-0.91	-1.12	-1.12	-1.12	-1.12
Total (TWh)	0.00	0.13	-2.51	-4.73	-6.85	-9.05	-9.05	-9.05	-9.05
Installed Generating Capacity									
Coal (GW)	0.00	-0.10	-0.16	-0.16	-0.16	-0.16	-0.16	-0.16	-0.16
Other Fossil (GW)	0.00	-0.08	-0.27	-0.67	-1.27	-1.73	-1.73	-1.73	-1.73
Nuclear (GW)	0.00	0.00	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03
Renewables (GW)	0.00	-0.16	-0.16	-0.23	-0.27	-0.28	-0.28	-0.28	-0.28
Total (GW)	0.00	-0.34	-0.62	-1.10	-1.73	-2.21	-2.21	-2.21	-2.21

Table 14.3.7 Liquid Immersed Transformers Trial Standard Level 6 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,917	3,092	3,291	3,488
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,906	2,067	2,136	2,216
Gas (TWh)	1,009	999	999	997	1,144	1,276
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	607	672	702	723
Total (TWh)	4,136	4,237	4,433	4,657	4,903	5,135
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	489	529	569
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,193

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-2.73	-5.51	-8.35	-11.18	-13.90	-15.44	-16.42
Total U.S. Electric Generation									
Coal (TWh)	0.47	0.93	-1.18	-1.79	-1.91	-2.02	-2.02	-2.02	-2.02
Gas (TWh)	-0.47	-0.17	-0.93	-2.35	-4.53	-6.73	-6.73	-6.73	-6.73
Petroleum (TWh)	0.00	0.00	-0.02	-0.02	-0.01	-0.03	-0.03	-0.03	-0.03
Nuclear (TWh)	0.00	0.00	-0.30	-0.30	-0.29	-0.29	-0.29	-0.29	-0.29
Renewables (TWh)	0.00	-0.62	-0.37	-0.88	-1.03	-1.29	-1.29	-1.29	-1.29
Total (TWh)	0.00	0.14	-2.80	-5.33	-7.78	-10.36	-10.36	-10.36	-10.36
Installed Generating Capacity									
Coal (GW)	0.00	-0.11	-0.18	-0.18	-0.18	-0.19	-0.19	-0.19	-0.19
Other Fossil (GW)	0.00	-0.09	-0.30	-0.76	-1.44	-1.98	-1.98	-1.98	-1.98
Nuclear (GW)	0.00	0.00	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Renewables (GW)	0.00	-0.18	-0.18	-0.26	-0.30	-0.32	-0.32	-0.32	-0.32
Total (GW)	0.00	-0.38	-0.69	-1.24	-1.96	-2.53	-2.53	-2.53	-2.53

Table 14.3.8 Liquid Immersed Transformers Trial Standard Level 7 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,916	3,089	3,287	3,483
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,905	2,066	2,135	2,215
Gas (TWh)	1,009	999	999	996	1,142	1,273
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	555	607	672	702	722
Total (TWh)	4,136	4,237	4,432	4,655	4,899	5,130
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	489	528	568
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	175	180
Total (GW)	1,027	1,052	1,060	1,094	1,143	1,192

Difference from AEO2011 Reference Case

	2010	2015	2020	2025	2030	2035	Extrapolation 2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-3.82	-7.84	-12.08	-16.46	-20.81	-23.34	-24.96
Total U.S. Electric Generation									
Coal (TWh)	0.64	1.29	-1.65	-2.55	-2.76	-2.97	-2.97	-2.97	-2.97
Gas (TWh)	-0.64	-0.24	-1.31	-3.34	-6.56	-9.92	-9.92	-9.92	-9.92
Petroleum (TWh)	0.00	0.00	-0.02	-0.03	-0.01	-0.05	-0.05	-0.05	-0.05
Nuclear (TWh)	0.00	0.00	-0.42	-0.42	-0.43	-0.43	-0.43	-0.43	-0.43
Renewables (TWh)	-0.01	-0.86	-0.52	-1.25	-1.50	-1.89	-1.89	-1.89	-1.89
Total (TWh)	-0.01	0.19	-3.92	-7.58	-11.26	-15.25	-15.25	-15.25	-15.25
Installed Generating Capacity									
Coal (GW)	0.00	-0.15	-0.25	-0.26	-0.26	-0.28	-0.28	-0.28	-0.28
Other Fossil (GW)	0.00	-0.13	-0.42	-1.07	-2.08	-2.92	-2.92	-2.92	-2.92
Nuclear (GW)	0.00	0.00	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05
Renewables (GW)	0.00	-0.25	-0.25	-0.37	-0.44	-0.48	-0.48	-0.48	-0.48
Total (GW)	0.00	-0.53	-0.97	-1.76	-2.84	-3.73	-3.73	-3.73	-3.73

Table 14.3.9 Low Voltage Dry Type Transformers Trial Standard Level 1 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,918	3,094	3,293	3,492
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,906	2,067	2,136	2,217
Gas (TWh)	1,009	999	1,000	998	1,145	1,279
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	607	672	702	723
Total (TWh)	4,136	4,236	4,434	4,659	4,906	5,139
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	334
Other Fossil (GW)	471	471	469	490	529	570
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,144	1,194

Difference from AEO2011 Reference Case

	2010	2015	2020	2025	2030	2035	Extrapolation 2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-1.77	-3.57	-5.38	-7.18	-8.88	-9.84	-10.44
Total U.S. Electric Generation									
Coal (TWh)	0.30	0.60	-0.77	-1.16	-1.23	-1.29	-1.29	-1.29	-1.29
Gas (TWh)	-0.30	-0.11	-0.61	-1.52	-2.92	-4.32	-4.32	-4.32	-4.32
Petroleum (TWh)	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02	-0.02
Nuclear (TWh)	0.00	0.00	-0.19	-0.19	-0.19	-0.19	-0.19	-0.19	-0.19
Renewables (TWh)	0.00	-0.40	-0.24	-0.57	-0.67	-0.83	-0.83	-0.83	-0.83
Total (TWh)	0.00	0.09	-1.82	-3.45	-5.01	-6.65	-6.65	-6.65	-6.65
Installed Generating Capacity									
Coal (GW)	0.00	-0.07	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Other Fossil (GW)	0.00	-0.06	-0.19	-0.49	-0.93	-1.27	-1.27	-1.27	-1.27
Nuclear (GW)	0.00	0.00	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
Renewables (GW)	0.00	-0.12	-0.11	-0.17	-0.20	-0.21	-0.21	-0.21	-0.21
Total (GW)	0.00	-0.25	-0.45	-0.80	-1.26	-1.62	-1.62	-1.62	-1.62

Table 14.3.10 Low Voltage Dry Type Transformers Trial Standard Level 2 Forecast

NEMS-BT Results:							**Difference from AEO2011 Reference Case**									
														Extrapolation		
	2010	**2015**	**2020**	**2025**	**2030**	**2035**		**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2043**	**2045**
Residential and Commercial Sector Energy Consumption							*Residential and Commercial Sector Energy Consumption*									
Electricity Sales (TWh)	2,805	2,765	2,918	3,094	3,293	3,492	Electricity Sales (TWh)	0.00	0.00	-1.81	-3.65	-5.50	-7.34	-9.09	-10.07	-10.68
Total U.S. Electric Generation							*Total U.S. Electric Generation*									
Coal (TWh)	1,864	1,799	1,906	2,067	2,136	2,217	Coal (TWh)	0.31	0.62	-0.78	-1.18	-1.26	-1.32	-1.32	-1.32	-1.32
Gas (TWh)	1,009	999	999	998	1,145	1,279	Gas (TWh)	-0.31	-0.11	-0.62	-1.55	-2.99	-4.42	-4.42	-4.42	-4.42
Petroleum (TWh)	45	43	44	44	45	46	Petroleum (TWh)	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02	-0.02
Nuclear (TWh)	803	839	877	877	877	874	Nuclear (TWh)	0.00	0.00	-0.20	-0.20	-0.19	-0.19	-0.19	-0.19	-0.19
Renewables (TWh)	414	556	607	672	702	723	Renewables (TWh)	0.00	-0.41	-0.25	-0.58	-0.68	-0.84	-0.84	-0.84	-0.84
Total (TWh)	4,136	4,236	4,434	4,659	4,906	5,139	Total (TWh)	0.00	0.09	-1.86	-3.52	-5.13	-6.80	-6.80	-6.80	-6.80
Installed Generating Capacity							*Installed Generating Capacity*									
Coal (GW)	322	322	323	325	329	334	Coal (GW)	0.00	-0.07	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Other Fossil (GW)	471	471	469	490	529	570	Other Fossil (GW)	0.00	-0.06	-0.20	-0.50	-0.95	-1.30	-1.30	-1.30	-1.30
Nuclear (GW)	101	106	110	110	110	110	Nuclear (GW)	0.00	0.00	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
Renewables (GW)	132	154	158	169	176	180	Renewables (GW)	0.00	-0.12	-0.12	-0.17	-0.20	-0.21	-0.21	-0.21	-0.21
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,194	Total (GW)	0.00	-0.25	-0.46	-0.82	-1.29	-1.66	-1.66	-1.66	-1.66

Table 14.3.11 Low Voltage Dry Type Transformers Trial Standard Level 3 Forecast

NEMS-BT Results:							**Difference from AEO2011 Reference Case**									
														Extrapolation		
	2010	**2015**	**2020**	**2025**	**2030**	**2035**		**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2043**	**2045**
Residential and Commercial Sector Energy Consumption							*Residential and Commercial Sector Energy Consumption*									
Electricity Sales (TWh)	2,805	2,765	2,917	3,093	3,293	3,491	Electricity Sales (TWh)	0.00	0.00	-2.07	-4.17	-6.29	-8.39	-10.39	-11.51	-12.21
Total U.S. Electric Generation							*Total U.S. Electric Generation*									
Coal (TWh)	1,864	1,800	1,906	2,067	2,136	2,217	Coal (TWh)	0.35	0.70	-0.90	-1.35	-1.44	-1.51	-1.51	-1.51	-1.51
Gas (TWh)	1,009	999	999	998	1,145	1,278	Gas (TWh)	-0.35	-0.13	-0.71	-1.77	-3.42	-5.05	-5.05	-5.05	-5.05
Petroleum (TWh)	45	43	44	44	45	46	Petroleum (TWh)	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02	-0.02
Nuclear (TWh)	803	839	877	877	877	874	Nuclear (TWh)	0.00	0.00	-0.23	-0.22	-0.22	-0.22	-0.22	-0.22	-0.22
Renewables (TWh)	414	556	607	672	702	723	Renewables (TWh)	0.00	-0.47	-0.28	-0.66	-0.78	-0.96	-0.96	-0.96	-0.96
Total (TWh)	4,136	4,236	4,434	4,659	4,905	5,138	Total (TWh)	0.00	0.11	-2.12	-4.03	-5.86	-7.77	-7.77	-7.77	-7.77
Installed Generating Capacity							*Installed Generating Capacity*									
Coal (GW)	322	322	323	325	329	333	Coal (GW)	0.00	-0.08	-0.13	-0.14	-0.14	-0.14	-0.14	-0.14	-0.14
Other Fossil (GW)	471	471	469	490	529	570	Other Fossil (GW)	0.00	-0.07	-0.23	-0.57	-1.09	-1.49	-1.49	-1.49	-1.49
Nuclear (GW)	101	106	110	110	110	110	Nuclear (GW)	0.00	0.00	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03
Renewables (GW)	132	154	158	169	176	180	Renewables (GW)	0.00	-0.14	-0.13	-0.20	-0.23	-0.24	-0.24	-0.24	-0.24
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,194	Total (GW)	0.00	-0.29	-0.52	-0.93	-1.48	-1.90	-1.90	-1.90	-1.90

Table 14.3.12 Low Voltage Dry Type Transformers Trial Standard Level 4 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,917	3,091	3,290	3,487
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,906	2,067	2,135	2,216
Gas (TWh)	1,009	999	999	997	1,143	1,276
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	555	607	672	702	723
Total (TWh)	4,136	4,237	4,433	4,657	4,902	5,135
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	489	529	569
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,193

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-2.94	-5.94	-8.95	-11.95	-14.79	-16.38	-17.38
Total U.S. Electric Generation									
Coal (TWh)	0.50	1.00	-1.27	-1.93	-2.05	-2.15	-2.15	-2.15	-2.15
Gas (TWh)	-0.50	-0.19	-1.01	-2.53	-4.87	-7.20	-7.20	-7.20	-7.20
Petroleum (TWh)	0.00	0.00	-0.02	-0.02	-0.01	-0.03	-0.03	-0.03	-0.03
Nuclear (TWh)	0.00	0.00	-0.32	-0.32	-0.32	-0.31	-0.31	-0.31	-0.31
Renewables (TWh)	0.00	-0.67	-0.40	-0.94	-1.11	-1.37	-1.37	-1.37	-1.37
Total (TWh)	0.00	0.15	-3.02	-5.73	-8.35	-11.07	-11.07	-11.07	-11.07
Installed Generating Capacity									
Coal (GW)	0.00	-0.12	-0.19	-0.20	-0.19	-0.20	-0.20	-0.20	-0.20
Other Fossil (GW)	0.00	-0.10	-0.32	-0.81	-1.55	-2.12	-2.12	-2.12	-2.12
Nuclear (GW)	0.00	0.00	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Renewables (GW)	0.00	-0.19	-0.19	-0.28	-0.33	-0.35	-0.35	-0.35	-0.35
Total (GW)	0.00	-0.41	-0.75	-1.33	-2.10	-2.70	-2.70	-2.70	-2.70

Table 14.3.13 Low Voltage Dry Type Transformers Trial Standard Level 5 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,917	3,091	3,290	3,487
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,906	2,067	2,135	2,216
Gas (TWh)	1,009	999	999	997	1,143	1,276
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	555	607	672	702	723
Total (TWh)	4,136	4,237	4,433	4,657	4,902	5,134
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	489	529	569
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	176	180
Total (GW)	1,027	1,052	1,061	1,094	1,144	1,193

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-2.99	-6.04	-9.11	-12.16	-15.05	-16.67	-17.69
Total U.S. Electric Generation									
Coal (TWh)	0.51	1.02	-1.30	-1.96	-2.08	-2.19	-2.19	-2.19	-2.19
Gas (TWh)	-0.51	-0.19	-1.03	-2.57	-4.95	-7.32	-7.32	-7.32	-7.32
Petroleum (TWh)	0.00	0.00	-0.02	-0.02	-0.01	-0.04	-0.04	-0.04	-0.04
Nuclear (TWh)	0.00	0.00	-0.33	-0.32	-0.32	-0.31	-0.31	-0.31	-0.31
Renewables (TWh)	0.00	-0.68	-0.41	-0.96	-1.13	-1.40	-1.40	-1.40	-1.40
Total (TWh)	0.00	0.15	-3.08	-5.84	-8.49	-11.26	-11.26	-11.26	-11.26
Installed Generating Capacity									
Coal (GW)	0.00	-0.12	-0.20	-0.20	-0.20	-0.20	-0.20	-0.20	-0.20
Other Fossil (GW)	0.00	-0.10	-0.33	-0.83	-1.57	-2.16	-2.16	-2.16	-2.16
Nuclear (GW)	0.00	0.00	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Renewables (GW)	0.00	-0.20	-0.19	-0.28	-0.33	-0.35	-0.35	-0.35	-0.35
Total (GW)	0.00	-0.42	-0.76	-1.35	-2.14	-2.75	-2.75	-2.75	-2.75

Table 14.3.14 Low Voltage Dry Type Transformers Trial Standard Level 6 Forecast

NEMS-BT Results:	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,916	3,091	3,289	3,486
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,800	1,906	2,066	2,135	2,216
Gas (TWh)	1,009	999	999	997	1,143	1,275
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	555	607	672	702	723
Total (TWh)	4,136	4,237	4,433	4,657	4,902	5,134
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	333
Other Fossil (GW)	471	471	469	489	529	569
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	158	169	175	180
Total (GW)	1,027	1,052	1,061	1,094	1,143	1,193

Difference from AEO2011 Reference Case							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.00	0.00	-3.18	-6.42	-9.68	-12.92	-15.99	-17.72	-18.80
Total U.S. Electric Generation									
Coal (TWh)	0.54	1.09	-1.38	-2.08	-2.21	-2.33	-2.33	-2.33	-2.33
Gas (TWh)	-0.54	-0.20	-1.09	-2.73	-5.26	-7.78	-7.78	-7.78	-7.78
Petroleum (TWh)	0.00	0.00	-0.02	-0.02	-0.01	-0.04	-0.04	-0.04	-0.04
Nuclear (TWh)	0.00	0.00	-0.35	-0.35	-0.34	-0.33	-0.33	-0.33	-0.33
Renewables (TWh)	0.00	-0.72	-0.43	-1.02	-1.20	-1.49	-1.49	-1.49	-1.49
Total (TWh)	0.00	0.16	-3.27	-6.20	-9.03	-11.97	-11.97	-11.97	-11.97
Installed Generating Capacity									
Coal (GW)	0.00	-0.13	-0.21	-0.21	-0.21	-0.22	-0.22	-0.22	-0.22
Other Fossil (GW)	0.00	-0.11	-0.35	-0.88	-1.67	-2.29	-2.29	-2.29	-2.29
Nuclear (GW)	0.00	0.00	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Renewables (GW)	0.00	-0.21	-0.20	-0.30	-0.35	-0.38	-0.38	-0.38	-0.38
Total (GW)	0.00	-0.44	-0.81	-1.44	-2.28	-2.92	-2.92	-2.92	-2.92

Table 14.3.15 Medium Voltage Dry Type Transformers Trial Standard Level 1 Forecast

NEMS-BT Results:	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,919	3,097	3,299	3,499
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,907	2,068	2,137	2,218
Gas (TWh)	1,010	999	1,000	1,000	1,148	1,283
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	608	673	703	724
Total (TWh)	4,136	4,236	4,436	4,663	4,910	5,145
Installed Generating Capacity						
Coal (GW)	322	322	323	326	329	334
Other Fossil (GW)	471	471	470	490	530	571
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	159	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,146	1,195

Difference from AEO2011 Reference Case							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.000	0.000	-0.100	-0.201	-0.303	-0.404	-0.500	-0.554	-0.588
Total U.S. Electric Generation									
Coal (TWh)	0.017	0.034	-0.043	-0.065	-0.069	-0.073	-0.073	-0.073	-0.073
Gas (TWh)	-0.017	-0.006	-0.034	-0.085	-0.165	-0.243	-0.243	-0.243	-0.243
Petroleum (TWh)	0.000	0.000	-0.001	-0.001	0.000	-0.001	-0.001	-0.001	-0.001
Nuclear (TWh)	0.000	0.000	-0.011	-0.011	-0.011	-0.010	-0.010	-0.010	-0.010
Renewables (TWh)	0.000	-0.023	-0.014	-0.032	-0.038	-0.046	-0.046	-0.046	-0.046
Total (TWh)	0.000	0.005	-0.102	-0.194	-0.282	-0.374	-0.374	-0.374	-0.374
Installed Generating Capacity									
Coal (GW)	0.000	-0.004	-0.006	-0.007	-0.007	-0.007	-0.007	-0.007	-0.007
Other Fossil (GW)	0.000	-0.003	-0.011	-0.028	-0.052	-0.072	-0.072	-0.072	-0.072
Nuclear (GW)	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Renewables (GW)	0.000	-0.007	-0.006	-0.009	-0.011	-0.012	-0.012	-0.012	-0.012
Total (GW)	0.000	-0.014	-0.025	-0.045	-0.071	-0.091	-0.091	-0.091	-0.091

Table 14.3.16 Medium Voltage Dry Type Transformers Trial Standard Level 2 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,919	3,097	3,298	3,498
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,907	2,068	2,137	2,218
Gas (TWh)	1,010	999	1,000	1,000	1,148	1,283
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	608	673	703	724
Total (TWh)	4,136	4,236	4,436	4,662	4,910	5,145
Installed Generating Capacity						
Coal (GW)	322	322	323	326	329	334
Other Fossil (GW)	471	471	470	490	530	571
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	159	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,146	1,195

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.000	0.000	-0.190	-0.382	-0.577	-0.770	-0.953	-1.055	-1.120
Total U.S. Electric Generation									
Coal (TWh)	0.032	0.065	-0.082	-0.124	-0.132	-0.139	-0.139	-0.139	-0.139
Gas (TWh)	-0.032	-0.012	-0.065	-0.163	-0.313	-0.464	-0.464	-0.464	-0.464
Petroleum (TWh)	0.000	0.000	-0.001	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002
Nuclear (TWh)	0.000	0.000	-0.021	-0.021	-0.020	-0.020	-0.020	-0.020	-0.020
Renewables (TWh)	0.000	-0.043	-0.026	-0.061	-0.071	-0.088	-0.088	-0.088	-0.088
Total (TWh)	0.000	0.010	-0.195	-0.369	-0.538	-0.713	-0.713	-0.713	-0.713
Installed Generating Capacity									
Coal (GW)	0.000	-0.007	-0.012	-0.013	-0.013	-0.013	-0.013	-0.013	-0.013
Other Fossil (GW)	0.000	-0.007	-0.021	-0.052	-0.100	-0.136	-0.136	-0.136	-0.136
Nuclear (GW)	0.000	0.000	-0.003	-0.003	-0.003	-0.003	-0.003	-0.003	-0.003
Renewables (GW)	0.000	-0.012	-0.012	-0.018	-0.021	-0.022	-0.022	-0.022	-0.022
Total (GW)	0.000	-0.026	-0.048	-0.086	-0.136	-0.174	-0.174	-0.174	-0.174

Table 14.3.17 Medium Voltage Dry Type Transformers Trial Standard Level 3 Forecast

NEMS-BT Results:

	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,919	3,096	3,298	3,498
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,907	2,068	2,137	2,218
Gas (TWh)	1,010	999	1,000	999	1,148	1,282
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	608	673	703	724
Total (TWh)	4,136	4,236	4,436	4,662	4,910	5,144
Installed Generating Capacity						
Coal (GW)	322	322	323	326	329	334
Other Fossil (GW)	471	471	470	490	530	571
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	159	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,145	1,195

Difference from AEO2011 Reference Case

							Extrapolation		
	2010	2015	2020	2025	2030	2035	2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.000	0.000	-0.361	-0.729	-1.100	-1.467	-1.816	-2.011	-2.134
Total U.S. Electric Generation									
Coal (TWh)	0.062	0.123	-0.157	-0.237	-0.251	-0.264	-0.264	-0.264	-0.264
Gas (TWh)	-0.062	-0.023	-0.124	-0.310	-0.597	-0.884	-0.884	-0.884	-0.884
Petroleum (TWh)	0.000	0.000	-0.002	-0.002	-0.001	-0.004	-0.004	-0.004	-0.004
Nuclear (TWh)	0.000	0.000	-0.040	-0.039	-0.039	-0.038	-0.038	-0.038	-0.038
Renewables (TWh)	-0.001	-0.082	-0.049	-0.116	-0.136	-0.169	-0.169	-0.169	-0.169
Total (TWh)	0.000	0.018	-0.371	-0.704	-1.025	-1.359	-1.359	-1.359	-1.359
Installed Generating Capacity									
Coal (GW)	0.000	-0.014	-0.024	-0.024	-0.024	-0.025	-0.025	-0.025	-0.025
Other Fossil (GW)	0.000	-0.012	-0.040	-0.100	-0.190	-0.260	-0.260	-0.260	-0.260
Nuclear (GW)	0.000	0.000	-0.005	-0.005	-0.005	-0.005	-0.005	-0.005	-0.005
Renewables (GW)	0.000	-0.024	-0.023	-0.034	-0.040	-0.043	-0.043	-0.043	-0.043
Total (GW)	0.000	-0.050	-0.092	-0.163	-0.258	-0.332	-0.332	-0.332	-0.332

Table 14.3.18 Medium Voltage Dry Type Transformers Trial Standard Level 4 Forecast

NEMS-BT Results:	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,919	3,096	3,298	3,498
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,907	2,068	2,137	2,218
Gas (TWh)	1,010	999	1,000	999	1,148	1,282
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	608	673	703	724
Total (TWh)	4,136	4,236	4,436	4,662	4,910	5,144
Installed Generating Capacity						
Coal (GW)	322	322	323	326	329	334
Other Fossil (GW)	471	471	470	490	530	571
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	159	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,145	1,195

Difference from AEO2011 Reference Case	2010	2015	2020	2025	2030	2035	Extrapolation 2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.000	0.000	-0.361	-0.729	-1.100	-1.467	-1.816	-2.011	-2.134
Total U.S. Electric Generation									
Coal (TWh)	0.062	0.123	-0.157	-0.237	-0.251	-0.264	-0.264	-0.264	-0.264
Gas (TWh)	-0.062	-0.023	-0.124	-0.310	-0.597	-0.884	-0.884	-0.884	-0.884
Petroleum (TWh)	0.000	0.000	-0.002	-0.002	-0.001	-0.004	-0.004	-0.004	-0.004
Nuclear (TWh)	0.000	0.000	-0.040	-0.039	-0.039	-0.038	-0.038	-0.038	-0.038
Renewables (TWh)	-0.001	-0.082	-0.049	-0.116	-0.136	-0.169	-0.169	-0.169	-0.169
Total (TWh)	0.000	0.018	-0.371	-0.704	-1.025	-1.359	-1.359	-1.359	-1.359
Installed Generating Capacity									
Coal (GW)	0.000	-0.014	-0.024	-0.024	-0.024	-0.025	-0.025	-0.025	-0.025
Other Fossil (GW)	0.000	-0.012	-0.040	-0.100	-0.190	-0.260	-0.260	-0.260	-0.260
Nuclear (GW)	0.000	0.000	-0.005	-0.005	-0.005	-0.005	-0.005	-0.005	-0.005
Renewables (GW)	0.000	-0.024	-0.023	-0.034	-0.040	-0.043	-0.043	-0.043	-0.043
Total (GW)	0.000	-0.050	-0.092	-0.163	-0.258	-0.332	-0.332	-0.332	-0.332

Table 14.3.19 Medium Voltage Dry Type Transformers Trial Standard Level 5 Forecast

NEMS-BT Results:	2010	2015	2020	2025	2030	2035
Residential and Commercial Sector Energy Consumption						
Electricity Sales (TWh)	2,805	2,765	2,919	3,096	3,297	3,497
Total U.S. Electric Generation						
Coal (TWh)	1,864	1,799	1,907	2,068	2,137	2,218
Gas (TWh)	1,010	999	1,000	999	1,147	1,282
Petroleum (TWh)	45	43	44	44	45	46
Nuclear (TWh)	803	839	877	877	877	874
Renewables (TWh)	414	556	608	673	703	724
Total (TWh)	4,136	4,236	4,436	4,662	4,909	5,144
Installed Generating Capacity						
Coal (GW)	322	322	323	325	329	334
Other Fossil (GW)	471	471	470	490	530	571
Nuclear (GW)	101	106	110	110	110	110
Renewables (GW)	132	154	159	169	176	180
Total (GW)	1,027	1,052	1,061	1,095	1,145	1,195

Difference from AEO2011 Reference Case	2010	2015	2020	2025	2030	2035	Extrapolation 2040	2043	2045
Residential and Commercial Sector Energy Consumption									
Electricity Sales (TWh)	0.000	0.000	-0.554	-1.119	-1.687	-2.251	-2.786	-3.087	-3.276
Total U.S. Electric Generation									
Coal (TWh)	0.094	0.189	-0.240	-0.363	-0.386	-0.406	-0.406	-0.406	-0.406
Gas (TWh)	-0.095	-0.035	-0.190	-0.476	-0.917	-1.356	-1.356	-1.356	-1.356
Petroleum (TWh)	0.000	0.000	-0.003	-0.004	-0.002	-0.007	-0.007	-0.007	-0.007
Nuclear (TWh)	0.000	0.000	-0.061	-0.060	-0.059	-0.058	-0.058	-0.058	-0.058
Renewables (TWh)	-0.001	-0.126	-0.076	-0.178	-0.209	-0.259	-0.259	-0.259	-0.259
Total (TWh)	-0.001	0.028	-0.570	-1.081	-1.573	-2.085	-2.085	-2.085	-2.085
Installed Generating Capacity									
Coal (GW)	0.000	-0.022	-0.036	-0.037	-0.037	-0.038	-0.038	-0.038	-0.038
Other Fossil (GW)	0.000	-0.019	-0.061	-0.153	-0.291	-0.399	-0.399	-0.399	-0.399
Nuclear (GW)	0.000	0.000	-0.008	-0.008	-0.007	-0.007	-0.007	-0.007	-0.007
Renewables (GW)	0.000	-0.037	-0.036	-0.053	-0.061	-0.065	-0.065	-0.065	-0.065
Total (GW)	0.000	-0.077	-0.141	-0.251	-0.397	-0.510	-0.510	-0.510	-0.510

Table 14.3.20 presents the estimated reduction in electricity generating capacity in 2045 for the TSLs that DOE considered in this rulemaking.

Table 14.3.20 Reduction in Electric Generating Capacity in 2045 Under Transformer Trial Standard Levels

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
	Gigawatts						
Liquid Immersed	0.610	1.23	1.33	2.24	2.21	2.53	3.73
Low Voltage Dry Type	1.62	1.66	1.90	2.70	2.75	2.92	--
Medium Voltage Dry Type	0.091	0.174	0.332	0.332	0.510	--	--
Total	2.33	3.06	3.56	5.28	5.47	5.46	3.73

14.4 IMPACT OF STANDARDS ON ELECTRICITY PRICES AND ASSOCIATED BENEFITS FOR CONSUMERS

Using the framework of the utility impact analysis, DOE analyzed the potential impact on electricity prices resulting from energy conservation standards for transformers. Associated benefits for all electricity users in all sectors of the economy are then derived from these price impacts.

DOE's analysis of energy price impacts used NEMS-BT in a similar manner as described in section 14.2. Like other widely-used energy-economic models, NEMS uses elasticities to estimate the energy price change that would result from a change (increase or decrease) in energy demand. The elasticity of price to a decrease in demand is the "inverse price elasticity." The calculated inverse price elasticity based on NEMS-BT simulations differs throughout the forecast period in response to the dynamics of supply and demand for electricity.

14.4.1 Impact on Electricity Prices

DOE analyzed the electricity price effect of energy conservation standards for all three types of transformers considered in this rulemaking. After generating results using higher decrements to energy consumption, a regressed interpolation toward the origin derived the price effects associated with the energy savings of the TSLs. Results were then scaled to the appropriate TSL; the proposed standard for each transformer type are TSL 1 for liquid immersed type, TSL 1 for low-voltage dry-type, and TSL 2 for medium-voltage dry-type. The electricity price impacts from all three types of transformers were aggregated into a single impact.

Figure 14.4.1 shows the annual change in U.S. electricity sales for the proposed standards, relative to the base case which involves no new standards.

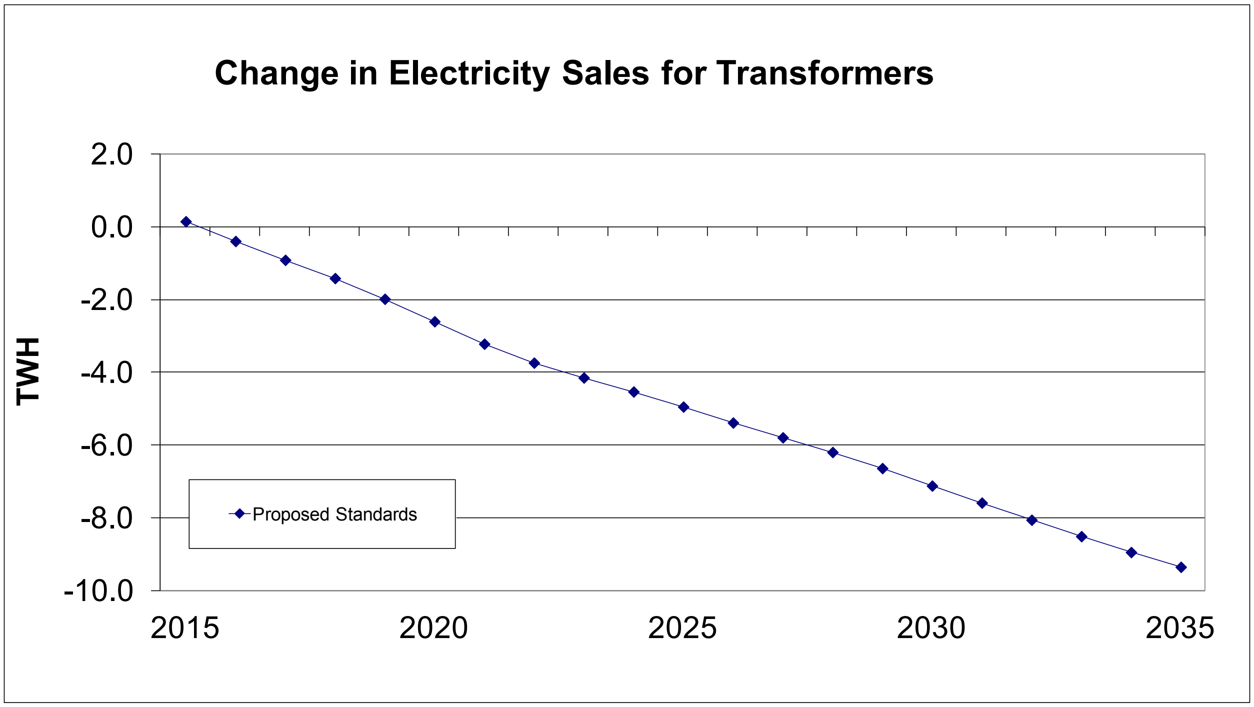

Figure 14.4.1 Change in U.S. Electricity Sales Associated with Amended Transformer Energy Conservation Standard

Figure 14.4.2 shows the annual change in average U.S. price for electricity, relative to the Reference case, projected to result from the proposed standards. The price reduction averages 0.005 cents per kWh (in 2010$), or a price reduction of 0.05 percent, over the period from 2016 through 2035.

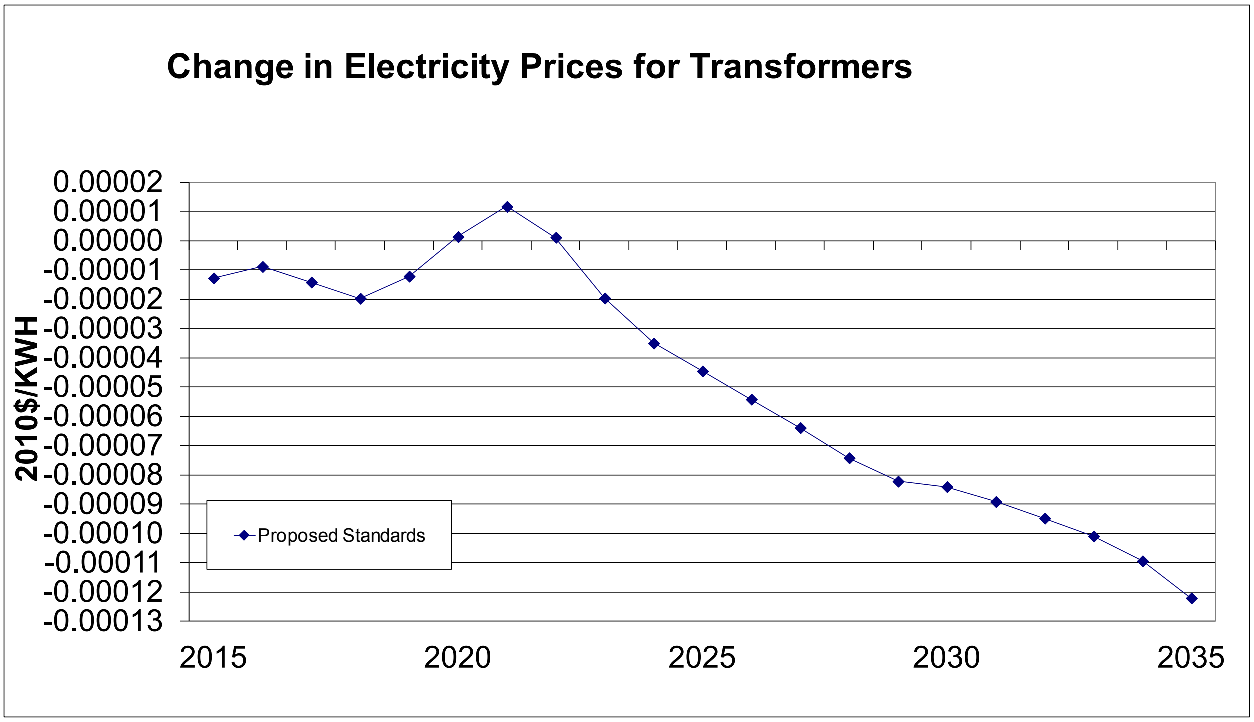

Figure 14.4.2 Effect of Proposed Transformer Energy Conservation Standard on Average U.S. Electricity Price (All Users)

14.4.2 Impact of Changes in Electricity Price on Electricity Users

Using the estimated electricity price impacts, DOE calculated the nominal savings in total electricity expenditures in each year by multiplying the annual change in the average-user price for electricity by the total annual U.S. electricity sales forecast by NEMS, adjusted for the impact of the standards. The proposed standards would continue to reduce demand for electricity after 2035 (which is the last year in the NEMS forecast). DOE's estimate for 2036–2045 (the period used to estimate the NPV of the national consumer benefits from proposed standards) multiplied the average electricity price reduction in 2016–2035 by estimated total annual electricity sales in 2036–2045.[c] DOE then discounted the stream of reduced expenditures to calculate a NPV.

Table 14.4.1 shows the calculated NPV of the economy-wide savings in electricity expenditures for each considered TSL at 3-percent and 7-percent discount rates. The need to

[c] The estimation of electricity sales after 2035 uses the average annual growth rate in 2031-2035 of total U.S. electricity sales forecasted by NEMS. This forecast includes the impact of the standards.

extrapolate price effects and electricity sales beyond 2035 suggests that one should interpret the post-2035 results as a rough indication of the benefits to electricity users in the post-2035 period.

Table 14.4.1 Cumulative NPV of the Economy-Wide Savings in Electricity Expenditures Due to the Projected Decline in Electricity Prices Resulting from the Proposed Standards for Transformers*

Discount Rate	Transformers *(billion $2010)*
3 percent	3.597
7 percent	1.695

* Impacts for units sold from 2016 to 2045

14.4.3 Discussion of Savings in Electricity Expenditures

Although the aggregate benefits for all electricity users are potentially large, there may be negative effects on the actors involved in electricity supply. The electric power industry is a complex mix of power plant providers, fuel suppliers, electricity generators, and electricity distributors. While the distribution of electricity is regulated everywhere, the institutional structure of the power sector varies, and has changed over time. For these reasons, an assessment of impacts on the actors involved in electricity supply from reduction in electricity demand associated with energy conservation standards is beyond the scope of this rulemaking.

In considering the potential benefits to electricity users, DOE takes under advisement the 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”). Specifically, at page 38, Circular A-4 instructs that transfers should be excluded from the estimates of the benefits and costs of a regulation. DOE is continuing to investigate the extent to which change in electricity prices projected to result from standards represents a net gain to society.

REFERENCES

1. Energy Information Administration, *Updated Annual Energy Outlook 2010 Reference Case Service Report*, 2010. Washington, DC. Report No. DOE/EIA-0383(2010). <http://www.eia.doe.gov/oiaf/aeo/>

CHAPTER 15. EMISSIONS ANALYSIS

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CHAPTER 15. EMISSIONS ANALYSIS

15.1 INTRODUCTION

This chapter describes potential changes to emissions of carbon dioxide (CO_2) and three air pollutants that may result from proposed energy conservation standards for residential and commercial transformers. The impacts on air emissions are largely driven by changes in power plant types and quantities of electricity generated under each of the considered standard levels. Changes in electricity generation are described in the utility impact analysis in chapter 14.

15.1 AIR EMISSIONS DESCRIPTIONS AND REGULATION

This analysis considers three pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_X), and mercury (Hg). An air pollutant is any substance in the air that can cause harm to humans or the environment. Pollutants may be natural or man-made (i.e., anthropogenic) and may take the form of solid particles (i.e., particulates or particulate matter), liquid droplets, or gases.[a] DOE's analysis also considers carbon dioxide (CO_2).

Sulfur Dioxide. Sulfur dioxide, or SO_2, belongs to the family of sulfur oxide gases (SOx). These gases dissolve easily in water. Sulfur is prevalent in all raw materials, including crude oil, coal, and ore that contains common metals like aluminum, copper, zinc, lead, and iron. SOx gases are formed when fuel containing sulfur, such as coal and oil, is burned, and when gasoline is extracted from oil, or metals are extracted from ore. SO_2 dissolves in water vapor to form acid, and interacts with other gases and particles in the air to form sulfates and other products that can be harmful to people and their environment.[i]

Nitrogen Oxides. Nitrogen oxides**,** or NO_X, is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. Many of the nitrogen oxides are colorless and odorless. However, one common pollutant, nitrogen dioxide (NO_2), along with particles in the air can often be seen as a reddish-brown layer over many urban areas. NO_2 is the specific form of NO_X reported in this document. NO_X is one of the main ingredients involved in the formation of ground-level ozone, which can trigger serious respiratory problems. It can contribute to the formation of acid rain, and can impair visibility in areas such as national parks. NO_X also contributes to the formation of fine particles that can impair human health.[ii]

Nitrogen oxides form when fossil fuel is burned at high temperatures, as in a combustion process. The primary manmade sources of NO_X are motor vehicles, electric utilities, and other industrial, commercial, and residential sources that burn fossil fuels. NO_X can also be formed naturally. Electric utilities account for about 22 percent of NO_X emissions in the United States.[2]

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[a] More information on air pollution characteristics and regulations is available on the U.S. Environment Protection Agent (EPA)'s website at www.epa.gov.

Mercury. Coal-fired power plants emit mercury (Hg) found in coal during the burning process. While coal-fired power plants are the largest remaining source of human-generated Hg emissions in the United States, they contribute very little to the global Hg pool or to contamination of U.S. waters.[iii] U.S. coal-fired power plants emit Hg in three different forms: oxidized Hg (likely to deposit within the United States); elemental Hg, which can travel thousands of miles before depositing to land and water; and Hg that is in particulate form. Atmospheric Hg is then deposited on land, lakes, rivers, and estuaries through rain, snow, and dry deposition. Once there, it can transform into methylmercury and accumulate in fish tissue through bioaccumulation.

Americans are exposed to methylmercury primarily by eating contaminated fish. Because the developing fetus is the most sensitive to the toxic effects of methylmercury, women of childbearing age are regarded as the population of greatest concern. Children exposed to methylmercury before birth may be at increased risk of poor performance on neurobehavioral tasks, such as those measuring attention, fine motor function, language skills, visual-spatial abilities, and verbal memory.[iv]

Carbon Dioxide. Carbon dioxide (CO_2) is not a criteria pollutant (see below), but it is of interest because of its classification as a greenhouse gas (GHG). GHGs trap the sun's radiation inside the Earth's atmosphere and either occur naturally in the atmosphere or result from human activities. Naturally occurring GHGs include water vapor, CO_2, methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Human activities, however, add to the levels of most of these naturally occurring gases. For example, CO_2 is emitted to the atmosphere when solid waste, fossil fuels (oil, natural gas, and coal), wood, and wood products are burned. In 2007, over 90 percent of anthropogenic (i.e., human-made) CO_2 emissions resulted from burning fossil fuels.[v]

Concentrations of CO_2 in the atmosphere are naturally regulated by numerous processes, collectively known as the "carbon cycle." The movement of carbon between the atmosphere and the land and oceans is dominated by natural processes, such as plant photosynthesis. While these natural processes can absorb some of the anthropogenic CO_2 emissions produced each year, billions of metric tons are added to the atmosphere annually. In the United States, in 2007, CO_2 emissions from electricity generation accounted for 39 percent of total U.S. GHG emissions.[5]

Particulate Matter. Particulate matter (PM), also known as particle pollution, is a complex mixture of extremely small particles and liquid droplets. Particle pollution is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

PM impacts are of concern due to human exposures that can impact health. Particle pollution - especially fine particles - contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including: increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

DOE acknowledges that particulate matter (PM) exposure can impact human health. Power plant emissions can have either direct or indirect impacts on PM. A portion of the pollutants emitted by a power plant are in the form of particulates as they leave the smoke stack. These are direct, or primary, PM emissions. However, the great majority of PM emissions associated with power plants are in the form of secondary sulfates, which are produced at a significant distance from power plants by complex atmospheric chemical reactions that often involve the gaseous (non-particulate) emissions of power plants, mainly SO_2 and NO_x. The quantity of the secondary sulfates produced is determined by a very complex set of factors including the atmospheric quantities of SO_2 and NO_x, and other atmospheric constituents and conditions. Because these highly complex chemical reactions produce PM comprised of different constituents from different sources, EPA does not distinguish direct PM emissions from power plants from the secondary sulfate particulates in its ambient air quality requirements, PM monitoring of ambient air quality, or PM emissions inventories. For these reasons, it is not currently possible to determine how the amended standard impacts either direct or indirect PM emissions. Therefore, DOE is not planning to assess the impact of these standards on PM emissions. Further, as described below, it is uncertain whether efficiency standards will result in a net decrease in power plant emissions of $SO_{2,}$ and of NO_x in many States, since those pollutants are now largely regulated by cap and trade systems.

Air Quality Regulation. The Clean Air Act Amendments of 1990 list 188 toxic air pollutants that EPA is required to control.[vi] EPA has set national air quality standards for six common pollutants (also referred to as "criteria" pollutants), two of which are SO_2 and NO_X. Also, the Clean Air Act Amendments of 1990 gave EPA the authority to control acidification and to require operators of electric power plants to reduce emissions of SO_2 and NO_X. Title IV of the 1990 amendments established a cap-and-trade program for SO_2, in all 50 states and the District of Columbia (D.C.), intended to help control acid rain.[6] This cap-and-trade program serves as a model for more recent programs with similar features.

In 2005, EPA issued the Clean Air Interstate Rule (CAIR) under sections 110 and 111 of the Clean Air Act (40 CFR Parts 51, 96, and 97).[b] 70 FR 25162–25405 (May 12, 2005). CAIR limited emissions from 28 eastern States and D.C. by capping emissions and creating an allowance-based trading program. Although, CAIR was remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), (see North Carolina v. EPA, 550 F.3d 1176 (D.C. Cir. 2008),) it remained in effect temporarily, consistent with the D.C. Circuit's earlier opinion in North Carolina v. EPA, 531 F.3d 896 (D.C. Cir. 2008).

On July 6, 2010, EPA issued the Transport Rule proposal, a replacement for CAIR. 75 FR 45210 (Aug. 2, 2010). On July 6, 2011, EPA promulgated the final Transport Rule, entitled "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals," but commonly referred to as the Cross-State Air Pollution Rule or the Transport Rule. 76 FR 48208 (Aug. 8, 2011).

[b] See http://www.epa.gov/cleanairinterstaterule/.

With respect to Hg emissions, in 2005, EPA issued the final rule entitled "Standards of Performance for New and Existing Stationary Sources: Electric Steam Generating Units," under sections 110 and 111 of the Clean Air Act (40 CFR Parts 60, 63, 72, and 75).[vii] This rule, called the Clean Air Mercury Rule (CAMR), was closely related to the CAIR and established standards of performance for Hg emissions from new and existing coal-fired electric utility steam generating units. The CAMR regulated Hg emissions from coal-fired power plants. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its decision in State of New Jersey, *et al.* v. Environmental Protection Agency,[c] in which the Court, among other actions, vacated the CAMR.

15.2 GLOBAL CLIMATE CHANGE

Climate change has evolved into a matter of global concern because it is expected to have widespread, adverse effects on natural resources and systems. A growing body of evidence points to anthropogenic sources of greenhouse gases, such as carbon dioxide (CO_2), as major contributors to climate change. Because this rule, if finalized, will likely decrease CO_2 emission rates from the fossil fuel sector in the United States, the Department here examines the impacts and causes of climate change and then the potential impact of the rule on CO_2 emissions and global warming.

Impacts of Climate Change on the Environment. Climate is usually defined as the average weather, over a period ranging from months to many years. Climate change refers to a change in the state of the climate, which is identifiable through changes in the mean and/or the variability of its properties (e.g., temperature or precipitation) over an extended period, typically decades or longer.

The World Meteorological Organization and United Nations Environment Programme (UNEP) established the Intergovernmental Panel on Climate Change (IPCC) to provide an objective source of information about climate change. According to the IPCC Fourth Assessment Report (IPCC Report), published in 2007, climate change is consistent with observed changes to the world's natural systems; the IPCC expects these changes to continue. [viii]

Changes that are consistent with warming include warming of the world's oceans to a depth of 3000 meters; global average sea level rise at an average rate of 1.8 mm per year from 1961 to 2003; loss of annual average Arctic sea ice at a rate of 2.7 percent per decade, changes in wind patterns that affect extra-tropical storm tracks and temperature patterns, increases in intense precipitation in some parts of the world, as well as increased drought and more frequent heat waves in many locations worldwide, and numerous ecological changes.[8]

Looking forward, the IPCC describes continued global warming of about 0.2 °C per decade for the next two decades under a wide range of emission scenarios for carbon dioxide (CO_2), other greenhouse gases (GHGs), and aerosols. After that period, the rate of increase is less certain. The IPCC Report describes increases in average global temperatures of about 1.1 °C

[c] 517 F.3d 574, 583 (D.C. Cir. 2008).

to 6.4 °C at the end of the century relative to today. These increases vary depending on the model and emissions scenarios.[8]

The IPCC Report describes incremental impacts associated with the rise in temperature. At ranges of incremental increases to the global average temperature, IPCC reports, with either high or very high confidence, that there is likely to be an increasing degree of impacts such as coral reef bleaching, loss of wildlife habitat, loss to specific ecosystems, and negative yield impacts for major cereal crops in the tropics, but also projects that there likely will be some beneficial impacts on crop yields in temperate regions.

Causes of Climate Change. The IPCC Report states that the world has warmed by about 0.74 °C in the last 100 years. The IPCC Report finds that most of the temperature increase since the mid-20th century is very likely due to the increase in anthropogenic concentrations of CO_2 and other long-lived greenhouse gases such as methane and nitrous oxide in the atmosphere, rather than from natural causes.

Increasing the CO_2 concentration partially blocks the earth's re-radiation of captured solar energy in the infrared band, inhibits the radiant cooling of the earth, and thereby alters the energy balance of the planet, which gradually increases its average temperature. The IPCC Report estimates that currently, CO_2 makes up about 77 percent of the total CO_2-equivalent[d] global warming potential in GHGs emitted from human activities, with the vast majority (74 percent) of the CO_2 attributable to fossil fuel use.[ix] For the future, the IPCC Report describes a wide range of GHG emissions scenarios, but under each scenario CO_2 would continue to comprise above 70 percent of the total global warming potential.[9]

Stabilization of CO_2 Concentrations. Unlike many traditional air pollutants, CO_2 mixes thoroughly in the entire atmosphere and is long-lived. The residence time of CO_2 in the atmosphere is long compared to the emission processes. Therefore, the global cumulative emissions of CO_2 over long periods determine CO_2 concentrations because it takes hundreds of years for natural processes to remove the CO_2. Globally, 49 billion metric tons of CO_2 – equivalent of anthropogenic (man-made) greenhouse gases are emitted every year.[e] Of this annual total, fossil fuels contribute about 29 billion metric tons of CO_2.[x]

Researchers have focused on considering atmospheric CO_2 concentrations that likely will result in some level of global climate stabilization, and the emission rates associated with achieving the "stabilizing" concentrations by particular dates. They associate these stabilized CO_2 concentrations with temperature increases that plateau in a defined range. For example, at the low end, the IPCC Report scenarios target CO_2 stabilized concentrations range between 350 ppm and 400 ppm (essentially today's value)—because of climate inertia, concentrations in this

[d] GHGs differ in their warming influence (radiative forcing) on a global climate system due to their different radiative properties and lifetimes in the atmosphere. These warming influences may be expressed through a common metric based on the radiative forcing of CO_2, i.e., CO_2-equivalent. CO_2 equivalent emission is the amount of CO_2 emission that would cause the same- time integrated radiative forcing, over a given time horizon, as an emitted amount of other long- lived GHG or mixture of GHGs.

[e] Other non-fossil fuel contributors include CO_2 emissions from deforestation and decay from agriculture biomass; agricultural and industrial emissions of methane; and emissions of nitrous oxide and fluorocarbons.

low-end range would still result in temperatures projected to increase 2.0 °C to 2.4 °C above pre-industrial levels[f] (about 1.3 °C to 1.7 °C above today's levels). To achieve concentrations between 350 ppm to 400 ppm, the IPCC scenarios present that there would have to be a rapid downward trend in total annual global emissions of greenhouse gases to levels that are 50 to 85 percent below today's annual emission rates by no later than 2050. Since it is assumed that there would continue to be growth in global population and substantial increases in economic production, the scenarios identify required reductions in greenhouse gas emissions intensity (emissions per unit of output) of more than 90 percent. However, even at these rates, the scenarios describe some warming and some climate change is projected due to already accumulated CO_2 and GHGs in the atmosphere.[xi]

The Beneficial Impact of the Rule on CO_2 Emissions. It is anticipated that the Rule will reduce energy-related CO_2 emissions, particularly those associated with energy consumption in buildings. The U.S. Energy Information Administration (EIA) reports in its 2011 *Annual Energy Outlook* (*AEO2011*)[xii] that U.S. annual energy-related emissions of CO_2 in 2009 were about 5.4 billion metric tons, of which 1.2 billion tons were attributed to the residential buildings sector. Most of the greenhouse gas emissions attributed to residential buildings are emitted from fossil fuel-fired power plants that generate electricity used in this sector. In the *AEO2011* Reference Case, EIA projected that annual energy-related CO_2 emissions would grow from 5.4 billion metric tons in 2009 to 6.3 billion metric tons in 2035, an increase of 16 percent, while residential emissions would grow to from 1.17 billion metric tons to 1.23 billion metric tons, an increase of 5 percent.

The estimated cumulative CO_2 emission reductions from transformer energy conservation standards (shown as a range of alternative TSLs) during the 30-year analysis period are indicated in Table 15.3.1. Estimated CO_2 emission reductions in Table 15.3.1 only come from electricity generation (i.e., power plants). The estimated CO_2 emission reductions from electricity generation are calculated using the NEMS-BT model.

[f] IPCC Working Group 3 Table TS 2

Table 15.2.1 Reduction in Cumulative Energy-Related Emissions of CO_2 from 2016 through 2045 from Residential and Commercial Transformer Energy Conservation Standards

	Trial Standard Levels						
	TSL 1	**TSL 2**	**TSL 3**	**TSL 4**	**TSL 5**	**TSL 6**	**TSL 7**
	Million Metric Tons						
Liquid Immersed	31.2	62.7	67.7	113	112	128	186
Low Voltage Dry Type	82.1	83.9	96.0	137	139	148	--
Medium Voltage Dry Type	4.62	8.80	16.8	16.8	25.7	--	--
Total	118	155	180	267	277	275	186
Percent of Total Cumulative Emissions Reduction compared with the *AEO2011* Reference Case in 2016-2045	0.163	0.215	0.250	0.369	0.383	0.381	0.257

The Incremental Impact of the Rule on Climate Change. It is difficult to correlate specific emission rates with atmospheric concentrations of CO_2 and specific atmospheric concentrations with future temperatures because the IPCC Report describes a clear lag in the climate system between any given concentration of CO_2 (even if maintained for long periods) and the subsequent average worldwide and regional temperature, precipitation, and extreme weather regimes. For example, a major determinant of climate response is "equilibrium climate sensitivity", a measure of the climate system response to sustained radioactive forcing. It is defined as the global average surface warming following a doubling of carbon dioxide concentrations. The IPCC Report describes its estimated, numeric value as about 3 °C, but the likely range of that value is 2 °C to 4.5 °C, with cloud feedbacks the largest source of uncertainty. Further, as illustrated above, the IPCC Report scenarios for stabilization rates are presented in terms of a range of concentrations, which then correlates to a range of temperature changes. Thus, climate sensitivity is a key uncertainty for CO_2 mitigation scenarios that aim to meet specific temperature levels.

Because of how complex global climate systems are, it is difficult to know to what extent and when particular CO_2 emissions reductions will impact global warming. However, as Table 15.3.1 indicates, the rule is expected to reduce CO_2 emissions associated with energy consumption in buildings.

15.3 ANALYTICAL METHODS FOR AIR EMISSIONS

For each of the considered TSLs, DOE calculated total power-sector emissions based on output from the NEMS-BT model (see chapter 14 for description of the model).

Coal-fired electric generation is the single largest source of electricity in the United States. Because the mix of coals used significantly affects the emissions produced, the model includes a detailed representation of coal supply. The model considers the rank of the coal as well as the sulfur contents of the fuel used when determining optimal dispatch.

Within the NEMS-BT model, planning options for achieving emissions restrictions in the Clean Air Act Amendments include installing pollution control equipment on existing power plants and building new power plants with low emission rates. These methods for reducing emission are compared to dispatching options such as fuel switching and allowance trading. Environmental regulations also affect capacity expansion decisions. For instance, new plants are not allocated SO_2 emissions allowances according to the Clean Air Act Amendments. Consequently, the decision to build a particular capacity type must consider the cost (if any) of obtaining sufficient allowances. This could involve purchasing allowances or over-complying at an existing unit.

For this analysis, DOE used the version of NEMS-BT based on *AEO 2011*, which assumes the implementation of CAIR. Thus, DOE's analysis assumes the presence of nationwide emission caps on SO_2 and caps on NO_X emissions in the 28 States covered by CAIR. DOE expects that the NEMS-BT based on *AEO 2012* will incorporate implementation of the Transport Rule.

SO_2 emissions from affected Electric Generating Units (EGUs) are subject to nationwide and regional emissions cap and trading programs, and DOE has determined that these programs create uncertainty about the standards' impact on SO_2 emissions. The attainment of emissions caps is typically flexible among 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. However, if the standard resulted in a permanent increase in the quantity of unused emissions allowances, there would be an overall reduction in SO_2 emissions from the standards. While there remains some uncertainty about the ultimate effects of efficiency standards on SO_2 emissions covered by the existing cap and trade system, the NEMS-BT modeling system that DOE uses to forecast emissions reductions currently indicates that no physical reductions in power sector emissions would occur for SO_2.[g]

The CAIR established a cap on NO_x emissions in 28 eastern states and the District of Columbia. All these States and D.C. have elected to reduce their NOx emissions by participating in cap-and-trade programs for EGUs. Therefore, energy conservation standards for transformers

[g] In contrast to the modeling forecasts of NEMS-BT that SO_2 emissions will remain at the cap, during the years 2007 and 2008, SO_2 emissions were below the trading cap. This raises the possibility that standards could cause some reduction in SO_2 emissions. However, because DOE does not have a method to predict when emissions will be below the trading cap, it continues to reply on NEMS-BT and thus does not estimate SO_2 emissions reductions at this time.

may have little or no physical effect on these emissions in the 28 eastern States and the D.C. for the same reasons that they may have little or no physical effect on SO_2 emissions.

With respect to Hg, in the absence of CAMR or another trading program, a DOE standard would likely reduce Hg emissions and DOE uses NEMS-BT to estimate these emission reductions. However, DOE continues to review the impact of rules that reduce energy consumption on Hg emissions, and may revise its assessment of Hg emission reductions in future rulemakings.

As noted in chapter 14, NEMS-BT model forecasts end in year 2035. Rather than extrapolate beyond this year, DOE assumes that emissions impacts beyond 2035 are equal to the impacts in 2035.

15.4 EFFECTS ON POWER PLANT EMISSIONS

Table 15.5.1 shows *AEO2011* Reference Case power plant emissions in selected years. The Reference Case emissions are the emissions shown by the NEMS-BT model to result if none of the TSLs are promulgated (the base case).

Table 15.4.1 Power Sector Emissions Forecast from *AEO2011* Reference Case

NEMS-BT Results	2010	2015	2020	2025	2030	2035
CO_2 (million metric tons)	2,303	2,138	2,225	2,360	2,444	2,526
NO_X (million tons)	2.57	1.98	1.98	2.00	2.01	2.03
Hg (tons)	40.5	26.8	26.8	28.0	28.7	29.3

Table 15.5.2 through Table 15.5.4 show the estimated changes in power plant emissions of CO_2, $NO_{X,}$ and Hg in selected years for each of the TSLs considered in this rulemaking. As in Table 15.5.1, values for CO_2 are given in metric tons, while values for NO_X and Hg are given in short tons.

Table 15.4.2 Power Sector Emissions Impacts Forecasts for Liquid Immersed Transformer TSLs

NEMS-BT Results*	Difference from AEO2011 Reference Case									
							Extrapolation			Total
	2010	2015	2020	2025	2030	2035	2040	2043	2045	2016-2045
Standard Level 1										
CO_2 (Mt/yr)	0.000	0.150	-0.415	-0.796	-1.169	-1.508	-1.508	-1.508	-1.508	**-31.2**
NOx (1,000 tons/yr)	0.000	0.139	-0.370	-0.673	-0.963	-1.209	-1.209	-1.209	-1.209	**-25.5**
Hg (ton/yr)	0.004	0.003	0.001	-0.006	-0.009	-0.010	-0.010	-0.010	-0.010	**-0.209**
Standard Level 2										
CO_2 (Mt/yr)	0.00	0.30	-0.83	-1.59	-2.35	-3.03	-3.03	-3.03	-3.03	**-62.7**
NOx (1,000 tons/yr)	0.00	0.28	-0.74	-1.35	-1.93	-2.43	-2.43	-2.43	-2.43	**-51.2**
Hg (ton/yr)	0.007	0.006	0.001	-0.012	-0.018	-0.021	-0.021	-0.021	-0.021	**-0.420**
Sandard Level 3										
CO_2 (Mt/yr)	0.00	0.32	-0.89	-1.71	-2.53	-3.28	-3.28	-3.28	-3.28	**-67.7**
NOx (1,000 tons/yr)	0.00	0.30	-0.79	-1.45	-2.08	-2.63	-2.63	-2.63	-2.63	**-55.3**
Hg (ton/yr)	0.008	0.007	0.001	-0.013	-0.020	-0.023	-0.023	-0.023	-0.023	**-0.454**
Standard Level 4										
CO_2 (Mt/yr)	0.00	0.52	-1.46	-2.83	-4.23	-5.54	-5.54	-5.54	-5.54	**-113**
NOx (kt/yr)	0.00	0.48	-1.30	-2.40	-3.48	-4.44	-4.44	-4.44	-4.44	**-92.7**
Hg (ton/yr)	0.013	0.011	0.002	-0.021	-0.033	-0.038	-0.038	-0.038	-0.038	**-0.762**
Standard Level 5										
CO_2 (Mt/yr)	0.00	0.52	-1.44	-2.80	-4.17	-5.46	-5.46	-5.46	-5.46	**-112**
NOx (1,000 tons/yr)	0.00	0.48	-1.28	-2.37	-3.43	-4.38	-4.38	-4.38	-4.38	**-91.5**
Hg (ton/yr)	0.012	0.010	0.002	-0.021	-0.032	-0.038	-0.038	-0.038	-0.038	**-0.751**
Sandard Level 6										
CO_2 (Mt/yr)	0.00	0.57	-1.61	-3.15	-4.73	-6.25	-6.25	-6.25	-6.25	**-128**
NOx (1,000 tons/yr)	0.00	0.53	-1.43	-2.66	-3.90	-5.01	-5.01	-5.01	-5.01	**-104**
Hg (ton/yr)	0.014	0.012	0.002	-0.023	-0.037	-0.043	-0.043	-0.043	-0.043	**-0.857**
Sandard Level 7										
CO_2 (Mt/yr)	0.00	0.79	-2.25	-4.48	-6.85	-9.21	-9.21	-9.21	-9.21	**-186**
NOx (1,000 tons/yr)	0.00	0.73	-2.00	-3.79	-5.64	-7.38	-7.38	-7.38	-7.38	**-152**
Hg (ton/yr)	0.019	0.016	0.003	-0.033	-0.053	-0.063	-0.063	-0.063	-0.063	**-1.251**

*CO_2 results are in metric tons, NO_X and Hg results are in short tons.

Table 15.4.3 Power Sector Emissions Impact Forecasts for Low-Voltage Dry Type Transformer TSLs

NEMS-BT Results*	Difference from AEO2011 Reference Case									
							Extrapolation			Total
	2010	2015	2020	2025	2030	2035	2040	2043	2045	2016-2045
Standard Level 1										
CO_2 (Mt/yr)	0.00	0.37	-1.04	-2.04	-3.05	-4.01	-4.01	-4.01	-4.01	**-82.1**
NOx (1,000 tons/yr)	0.00	0.34	-0.93	-1.72	-2.51	-3.22	-3.22	-3.22	-3.22	**-67.0**
Hg (ton/yr)	0.009	0.008	0.001	-0.015	-0.024	-0.028	-0.028	-0.028	-0.028	**-0.551**
Standard Level 2										
CO_2 (Mt/yr)	0.00	0.38	-1.07	-2.08	-3.12	-4.11	-4.11	-4.11	-4.11	**-83.9**
NOx (1,000 tons/yr)	0.00	0.35	-0.95	-1.76	-2.57	-3.29	-3.29	-3.29	-3.29	**-68.6**
Hg (ton/yr)	0.009	0.008	0.001	-0.015	-0.024	-0.028	-0.028	-0.028	-0.028	**-0.564**
Sandard Level 3										
CO_2 (Mt/yr)	0.00	0.43	-1.22	-2.38	-3.57	-4.69	-4.69	-4.69	-4.69	**-96.0**
NOx (kt/yr)	0.00	0.40	-1.08	-2.01	-2.94	-3.76	-3.76	-3.76	-3.76	**-78.4**
Hg (ton/yr)	0.010	0.009	0.002	-0.018	-0.028	-0.032	-0.032	-0.032	-0.032	**-0.645**
Standard Level 4										
CO_2 (Mt/yr)	0.00	0.62	-1.73	-3.39	-5.08	-6.68	-6.68	-6.68	-6.68	**-137**
NOx (1,000 tons/yr)	0.00	0.57	-1.54	-2.87	-4.18	-5.36	-5.36	-5.36	-5.36	**-112**
Hg (ton/yr)	0.015	0.013	0.002	-0.025	-0.039	-0.046	-0.046	-0.046	-0.046	**-0.918**
Standard Level 5										
CO_2 (Mt/yr)	0.00	0.63	-1.76	-3.45	-5.17	-6.80	-6.80	-6.80	-6.80	**-139**
NOx (1,000 tons/yr)	0.00	0.58	-1.57	-2.92	-4.26	-5.45	-5.45	-5.45	-5.45	**-114**
Hg (ton/yr)	0.015	0.013	0.002	-0.026	-0.040	-0.047	-0.047	-0.047	-0.047	**-0.934**
Sandard Level 6										
CO_2 (Mt/yr)	0.00	0.67	-1.87	-3.67	-5.49	-7.23	-7.23	-7.23	-7.23	**-148**
NOx (1,000 tons/yr)	0.00	0.62	-1.67	-3.10	-4.53	-5.80	-5.80	-5.80	-5.80	**-121**
Hg (ton/yr)	0.016	0.014	0.002	-0.027	-0.043	-0.050	-0.050	-0.050	-0.050	**-0.992**

*CO_2 results are in metric tons, NO_X and Hg results are in short tons.

Table 15.4.4 Power Sector Emissions Impact Forecasts for Medium-Voltage Dry Type Transformer TSLs

NEMS-BT Results*	Difference from AEO2011 Reference Case									
							Extrapolation			Total
	2010	2015	2020	2025	2030	2035	2040	2043	2045	2016-2045
Standard Level 1										
CO_2 (Mt/yr)	0.000	0.021	-0.059	-0.115	-0.172	-0.226	-0.226	-0.226	-0.226	**-4.62**
NOx (1,000 tons/yr)	0.000	0.019	-0.052	-0.097	-0.142	-0.181	-0.181	-0.181	-0.181	**-3.77**
Hg (ton/yr)	0.001	0.000	0.000	-0.001	-0.001	-0.002	-0.002	-0.002	-0.002	**-0.031**
Standard Level 2										
CO_2 (Mt/yr)	0.000	0.040	-0.112	-0.218	-0.327	-0.430	-0.430	-0.430	-0.430	**-8.80**
NOx (1,000 tons/yr)	0.000	0.037	-0.099	-0.185	-0.270	-0.345	-0.345	-0.345	-0.345	**-7.19**
Hg (ton/yr)	0.001	0.001	0.000	-0.002	-0.003	-0.003	-0.003	-0.003	-0.003	**-0.059**
Sandard Level 3										
CO_2 (Mt/yr)	0.000	0.076	-0.213	-0.416	-0.624	-0.821	-0.821	-0.821	-0.821	**-16.8**
NOx (kt/yr)	0.000	0.070	-0.190	-0.352	-0.514	-0.658	-0.658	-0.658	-0.658	**-13.7**
Hg (ton/yr)	0.002	0.002	0.000	-0.003	-0.005	-0.006	-0.006	-0.006	-0.006	**-0.113**
Standard Level 4										
CO_2 (Mt/yr)	0.000	0.076	-0.213	-0.416	-0.624	-0.821	-0.821	-0.821	-0.821	**-16.8**
NOx (1,000 tons/yr)	0.000	0.070	-0.190	-0.352	-0.514	-0.658	-0.658	-0.658	-0.658	**-13.7**
Hg (ton/yr)	0.002	0.002	0.000	-0.003	-0.005	-0.006	-0.006	-0.006	-0.006	**-0.113**
Standard Level 5										
CO_2 (Mt/yr)	0.000	0.116	-0.327	-0.639	-0.957	-1.259	-1.259	-1.259	-1.259	**-25.7**
NOx (1,000 tons/yr)	0.000	0.108	-0.291	-0.541	-0.788	-1.010	-1.010	-1.010	-1.010	**-21.0**
Hg (ton/yr)	0.003	0.002	0.000	-0.005	-0.007	-0.009	-0.009	-0.009	-0.009	**-0.173**

*CO_2 results are in metric tons, NO_X and Hg results are in short tons.

15.5 EFFECTS ON UPSTREAM FUEL-CYCLE EMISSIONS

Upstream fuel-cycle emissions refer to the emissions associated with the amount of energy used in the upstream production and downstream consumption of electricity, including energy used at the power plant. Upstream processes include the mining of coal or extraction of natural gas, physical preparatory and cleaning processes, and transportation to the power plant. The NEMS-BT does a thorough accounting of emissions at the power plant due to downstream energy consumption, but does not account for upstream emissions (i.e., emissions from energy losses during coal and natural gas production). Thus, this analysis reports only power plant emissions.

However, previous DOE environmental assessment documents have developed approximate estimates of effects on upstream fuel-cycle emissions. These emissions factors provide the reader with a sense of the possible magnitude of upstream effects. These upstream emissions would be in addition to emissions from direct combustion.

Relative to the entire fuel cycle, estimates based on the work of Dr. Mark DeLuchi, and reported in earlier DOE environmental assessment documents, find that an amount approximately equal to eight percent, by mass, of emissions (including SO_2) from coal production are due to mining, preparation that includes cleaning the coal, and transportation from the mine to the power plant.[xiii] Transportation emissions include emissions from the fuel used by the mode of transportation that moves the coal from the mine to the power plant. In addition, based on Dr. DeLuchi's work, DOE estimated that an amount equal to approximately 14 percent of emissions from natural gas production result from upstream processes.

Emission factor estimates and corresponding percentages of contributions of upstream emissions from coal and natural gas production, relative to power plant emissions, are shown in Table 15.6.1 for CO_2 and NO_X. The percentages provide a means to estimate upstream emission savings based on changes in emissions from power plants. This approach does not address Hg emissions.

Table 15.5.1 Estimated Upstream Emissions of Air Pollutants as a Percentage of Direct Power Plant Combustion Emissions

Pollutant	Percent of Coal Combustion Emissions	Percent of Natural Gas Combustion Emissions
CO_2	2.7	11.9
NO_X	5.8	40

15.6 SUMMARY OF EMISSIONS IMPACTS

Table 15.7.1 summarizes the estimated emissions impacts for each of the TSLs for transformers by transformer type. It shows cumulative changes in emissions for CO_2, NO_X, and Hg for 2016 through 2045 for each of the TSLs. Cumulative CO_2, NO_X, and Hg emissions are reduced compared to the Reference case for all TSLs. For comparison, the cumulative power sector emissions in the *AEO2011* Reference case, over the period 2016 through 2045, are 72,245 Mt for CO_2, 60,161 kt for NOx, and 851 tons for Hg.

Table 15.6.1 Cumulative Emissions Reductions Under Transformer TSLs*

	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Liquid Immersed							
CO_2 (Mt)	31.2	62.7	67.7	113	112	128	186
NO_X (kt)	25.5	51.2	55.3	92.7	91.5	104	152
Hg (t)	0.209	0.420	0.454	0.762	0.751	0.857	1.25
Low Voltage Dry Type							
CO_2 (Mt)	82.1	83.9	96.0	137	139	148	--
NO_X (kt)	67.0	68.6	78.4	112	114	121	--
Hg (t)	0.551	0.564	0.645	0.918	0.934	0.992	--
Medium Voltage Dry Type							
CO_2 (Mt)	4.62	8.80	16.8	16.8	25.7	--	--
NO_X (kt)	3.77	7.19	13.7	13.7	21.0	--	--
Hg (t)	0.031	0.059	0.113	0.113	0.173	--	--

* Values for CO_2 are given in metric tons, while values for NO_X and Hg are given in short tons.

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CHAPTER 16. MONETIZATION OF EMISSION REDUCTIONS BENEFITS

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CHAPTER 16. MONETIZATION OF EMISSION REDUCTIONS BENEFITS

16.1 INTRODUCTION

As part of its assessment of energy conservation standards, DOE considered the estimated 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 of the TSLs considered. This chapter summarizes the basis for the estimated monetary values used for each of these emissions and presents the benefits estimates considered.

16.2 MONETIZING CARBON DIOXIDE EMISSIONS

16.2.1 Social Cost of Carbon

Under 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 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.

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 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.

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. For emissions (or emission reductions) that occur in later years, these values grow in real terms over time, as depicted in Table 16.2.1.

Table 16.2.1 Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton)

	Discount Rate			
	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

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 Research Council[a] 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. Consistent with the directive quoted above, 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 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

[a] National Research Council. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academies Press: Washington, DC. 2009.

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. DOE does not attempt to answer that question here.

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, the interagency group has 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, the interagency group will continue to explore the issues raised by this analysis and consider public comments as part of the ongoing interagency process.

16.2.2 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 CO2 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 of 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 (Dynamic Integrated Climate Economy), PAGE (Policy Analysis of the Greenhouse Effect), and FUND (Climate Framework for Uncertainty, Negotiation and Distribution)—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 Richard Newell and William Pizer)[b] 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.

16.2.3 Current Approach and Key Assumptions

Since 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.

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 U.S. Government 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 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.

[b] R. Newell and W. Pizer. "Discounting the Distant Future: How Much Do Uncertain Rates Increase Valuations?" J. Environ. Econ. Manage. 46 (2003) 52-71)

In summary, in considering the potential global benefits resulting from reduced CO_2 emissions, DOE used the most recent values identified by the interagency process, adjusted to 2010$ using the standard GDP deflator values for 2008 and 2009. For each of the four cases specified, the values used for emissions in 2010 were $4.9, $22.3, $36.5, and $67.6 per metric ton avoided (values expressed in 2010$). To monetize the CO_2 emissions reductions expected to result from amended standards for furnaces and central air conditioners and heat pumps, DOE used the values identified in Table A1 of the "Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866," which is reprinted in appendix 16-A of this TSD, appropriately escalated to 2010$. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the discount rates that had been used to obtain the SCC values in each case.

16.3 VALUATION OF OTHER EMISSIONS REDUCTIONS

As discussed in chapter 15, DOE's analysis assumed the presence of nationwide emission caps on SO_2 and caps on NO_X emissions in the 28 States covered by the CAIR. In the presence of these caps, the NEMS–BT modeling system that DOE used to forecast emissions reduction indicated that no physical reductions in power sector emissions would occur for SO_2, but that the standards could put slight downward pressure on the prices of emissions allowances in cap-and-trade markets. Estimating this effect is very difficult because such factors as credit banking can change the trajectory of prices. From its modeling to date, DOE is unable to estimate a benefit from SO_2 emissions reductions at this time.

DOE investigated the potential monetary benefit of reduced NO_X emissions from the TSLs it considered. As noted above, new or amended energy conservation standards would reduce NO_X emissions in those 22 States that are not affected by the CAIR, in addition to the reduction in site NO_X emissions nationwide. DOE estimated the monetized value of NO_X emissions reductions resulting from each of the TSLs considered for today's NOPR based on environmental damage estimates from the literature. Available estimates suggest a very wide range of monetary values, ranging from $370 per ton to $3,800 per ton of NO_X from stationary sources, measured in 2001$ (equivalent to a range of $447 to $4,591 per ton in 2010$).[c] In accordance with OMB guidance, DOE conducted two calculations of the monetary benefits derived using each of the economic values used for NO_X, one using a real discount rate of 3 percent and another using a real discount rate of 7 percent. [d]

DOE is aware of multiple agency efforts to determine the appropriate range of values used in evaluating the potential economic benefits of reduced Hg emissions. DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it once again monetizes Hg in its rulemakings.

[c] For additional information, refer to U.S. Office of Management and Budget, Office of Information and Regulatory Affairs, ''2006 Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities,'' Washington, DC.

[d] OMB, Circular A-4: Regulatory Analysis (Sept. 17, 2003).

16.4 RESULTS

Table 16.4.1 presents the global values of CO_2 emissions reductions at each TSL. DOE calculated domestic values as a range from 7 percent to 23 percent of the global values, and these results are presented in Table 16.4.2.

Table 16.4.1 Estimates of Global Present Value of CO_2 Emissions Reduction Under Distribution Transformer Trial Standard Levels

TSL	5% discount rate, average*	3% discount rate, average*	2.5% discount rate, average*	3% discount rate, 95th percentile*
	Million 2010$			
Liquid-Immersed				
1	173	1003	1747	3051
2	350	2026	3528	6160
3	382	2219	3866	6746
4	655	3831	6681	11643
5	646	3779	6591	11486
6	752	4414	7705	13414
7	1140	6754	11811	20523
Low-Voltage Dry-Type				
1	481	2820	4921	8570
2	492	2884	5032	8764
3	562	3297	5753	10020
4	800	4693	8190	14264
5	814	4776	8336	14517
6	866	5076	8858	15427
Medium-Voltage Dry-Type				
1	27	159	277	483
2	52	302	528	919
3	98	576	1006	1751
4	98	576	1006	1751
5	151	884	1543	2688

Table 16.4.2 Estimates of Domestic Present Value of CO_2 Emissions Reduction Under Distribution Transformer Trial Standard Levels

TSL	5% discount rate, average*	3% discount rate, average*	2.5% discount rate, average*	3% discount rate, 95th percentile*
	Million 2010$			
Liquid-Immersed				
1	12 to 40	70 to 231	122 to 402	214 to 702
2	24 to 80	142 to 466	247 to 812	431 to 1417
3	27 to 88	155 to 510	271 to 889	472 to 1552
4	46 to 151	268 to 881	468 to 1537	815 to 2678
5	45 to 149	265 to 869	461 to 1516	804 to 2642
6	53 to 173	309 to 1015	539 to 1772	939 to 3085
7	80 to 262	473 to 1553	827 to 2717	1437 to 4720
Low-Voltage Dry-Type				
1	33.7 to 110.6	197 to 649	344 to 1132	600 to 1971
2	34.4 to 113.1	202 to 663	352 to 1157	613 to 2016
3	39.4 to 129.3	231 to 758	403 to 1323	701 to 2305
4	56 to 184.1	329 to 1079	573 to 1884	998 to 3281
5	57 to 187.3	334 to 1099	583 to 1917	1016 to 3339
6	60.6 to 199.1	355 to 1167	620 to 2037	1080 to 3548
Medium-Voltage Dry-Type				
1	1.9 to 6.2	11.1 to 36.5	19.4 to 63.7	33.8 to 111
2	3.6 to 11.9	21.2 to 69.5	36.9 to 121.4	64.3 to 211.3
3	6.9 to 22.6	40.3 to 132.5	70.4 to 231.3	122.6 to 402.8
4	6.9 to 22.6	40.3 to 132.5	70.4 to 231.3	122.6 to 402.8
5	10.6 to 34.7	61.9 to 203.4	108 to 355	188.1 to 618.2

Table 16.4.3 presents the cumulative monetary value of the economic benefits associated with NO_X emissions reductions for each TSL, calculated using seven-percent and three-percent discount rates.

Table V.3 Estimates of Present Value of NO_X Emissions Reduction under Distribution Transformer Trial Standard Levels

TSL	3% discount rate	7% discount rate
	Million 2010$	
Liquid-Immersed		
1	9 to 94	3 to 32
2	19 to 191	6 to 64
3	20 to 208	7 to 69
4	35 to 356	11 to 117
5	34 to 351	11 to 115
6	40 to 408	13 to 132
7	60 to 616	19 to 194
Low-Voltage Dry-Type		
1	25 to 261	8 to 85
2	26 to 267	8 to 87
3	30 to 305	10 to 99
4	42 to 434	14 to 141
5	43 to 442	14 to 143
6	46 to 470	15 to 152
Medium-Voltage Dry-Type		
1	1 to 15	0 to 5
2	3 to 28	1 to 9
3	5 to 53	2 to 17
4	5 to 53	2 to 17
5	8 to 82	3 to 27

CHAPTER 17. REGULATORY IMPACT ANALYSIS FOR ENERGY CONSERVATION STANDARDS FOR ELECTRICAL DISTRIBUTION TRANSFORMERS

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CHAPTER 17. REGULATORY IMPACT ANALYSIS FOR ENERGY CONSERVATION STANDARDS FOR ELECTRICAL DISTRIBUTION TRANSFORMERS

17.1 INTRODUCTION

DOE of Energy (Department, or DOE) has determined that distribution transformer energy-efficiency standards constitute an "economically significant regulatory action" under Executive Order (E.O.) 12866 "Regulatory Planning and Review." 58 FR 51735, October 4, 1993. Therefore, the energy-efficiency standards require a regulatory impact analysis (RIA), which involves an evaluation of non-regulatory alternatives to the promulgated standards. This document evaluates several possible alternatives to the adopted standards, and compares the costs and benefits of each to the adopted standards. As described in section 17.2 of this report, the efficiency levels adopted by DOE are those in trial standard level (TSL) 1 for liquid-immersed distribution transformers and TSL 2 for medium-voltage, dry-type distribution transformers.

Under the Process Rule (*Procedures, Interpretations and Policies for Consideration of New or Revised Energy Conservation Standards for Consumer Products, 10 CFR 430, Subpart C, Appendix A*), DOE is committed to continually explore non-regulatory alternatives to standards. 62 FR 54817. DOE has prepared this regulatory analysis pursuant to E.O. 12866, which is subject to review under the Executive Order by the Office of Information and Regulatory Affairs (OIRA). 58 FR 51735.

DOE identified six major, non-regulatory alternatives to standards as representing feasible policy options to achieve potentially similar improvements in distribution transformer energy efficiency. Table 17.1.1 lists the six alternatives. DOE evaluated each of those alternatives that apply to the distribution transformers covered by this final rule in terms of its ability to achieve significant energy savings at a reasonable cost, and compared the effectiveness of each one to the effectiveness of the adopted standards. As discussed in section 17.2 below, DOE found that some of these policy alternatives would not have an impact on those transformers for which there are energy conservation standards and therefore did not analyze them further.

Table 17.1.1 Policy Alternatives to Adopted National Distribution Transformer Standards

No New Regulatory Action
Consumer Rebates
Consumer Tax Credits
Manufacturer Tax Credits
Voluntary Energy-Efficiency Targets

Early Replacement
Bulk Government Purchases

17.2 NON-REGULATORY POLICIES

17.2.1 Methodology

DOE used a modification of the national impact analysis (NIA) spreadsheet model to calculate the national energy savings (NES) and net present value (NPV) of consumer costs and benefits associated with each non-regulatory policy alternative. Chapter 10 of the technical support document (TSD) describes the NIA spreadsheet model.

DOE quantified the effect of each alternative on the purchase of products that meet *target levels,* which are defined as the efficiency levels in the proposed standards. After establishing the quantitative assumptions underlying each alternative, DOE appropriately revised inputs to the NIA spreadsheet model. The primary model input revised were market shares of products meeting target efficiency levels. These are also referred to as market efficiency distributions. DOE assumed that the proposed standards would affect 100% of the shipments of products that did not meet target levels in the base case, 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 and assumed that shipments of the least efficient models in the market would increase to the target efficiency level (e.g., first models at EL 0, then models at EL 1, etc.).

Increasing the efficiency of a product often increases its average installed cost. On the other hand, operating costs generally decrease because energy consumption declines. DOE therefore calculated consumer NPV for each non-regulatory alternative in the same away it did for the proposed standards. In some scenarios, increases in total installed costs are mitigated by government rebates or tax credits. Because DOE assumed that consumers would re-pay credits and rebates in some way (such as through additional taxes), DOE did not include the value of rebates or tax credits themselves as consumer benefits when calculating national NPV and instead treated them as transfers. DOE's analysis also excluded any administrative costs for the non-regulatory policies; including such costs would decrease NPV.

The key measures of the impact of each alternative are:

- ***National energy savings in quadrillion British thermal units (quads):*** Cumulative national primary energy savings for equipment bought in the period from the effective date of the policy case (2016) to the year 2045.
- ***Net present value***: The value of net monetary savings from equipment bought in the period from the effective date of the policy case (2016) to the year 2045. DOE calculated the NPV as the difference between the present value of equipment and operating expenditures (including energy) in the base case, and the present value of expenditures in

each alternative policy case. DOE calculated capacity and operating cost savings through the year 2105 for transformers purchased in the period 2016 to 2045.

17.2.2 Policy Assumptions

The impacts of non-regulatory policies are by nature uncertain, since they depend on program implementation and marketing efforts and the subsequent consumer behavior response. The projected impacts depend on the assumptions about the consumer participation rate and are therefore subject to more uncertainties than the impacts of mandatory standards, which DOE assumed would have full compliance. To increase the robustness of the analysis, DOE conducted a literature review on each non-regulatory policy and consulted with key experts to gather information on similar incentive programs that have been implemented in the U.S. By studying field experience with sample programs of each type, DOE sought to make credible assumptions of their potential market impacts. Section 17.3 below reports the conclusions from this research as they apply to the policy modeling assumptions and includes the corresponding literature citations.

Each of the policy alternatives to the adopted standards that DOE considered improves the average efficiency of new distribution transformers relative to the base case (no new regulatory action). The analysis considered that each alternative policy would induce consumers to purchase units at the target levels, the same efficiency levels as required by the adopted standards. In contrast to the adopted standards, however, the penetration rate in the alternative policy cases may not be 100 percent.

The adopted standards are TSL 1 for liquid-immersed transformers, TSL1 for medium-voltage dry-type transformers, and TSL 2 for medium-voltage dry-type transformers, as shown in Table 17.2.1. Section II of the final rule shows the efficiency levels for the adopted standard levels by equipment class and kilovolt-ampere (kVA) size.

The size of the eligible market for the policies varies among the equipment classes. Table 17.2.1 shows the percentages of the distribution transformer market that DOE projects will be below the target levels in 2016 (in the column labeled "Percent Non-Compliant"). Therefore, policies that aim for the target level will impact the non-complying portion of the distribution transformer market for each equipment class. Non-regulatory policies would thus impact some fraction of these portions of the market.

DOE assumed that the non-regulatory policy impacts last from the effective date for adopted distribution transformer standards, 2016, through the end of the analysis period, 2045.

Table 17.2.1 Adopted Standard Levels for Distribution Transformers

Distribution Transformer Type	TSL	Percent Non-Compliant
Liquid Immersed	1	72.7
Low-Voltage Dry-Type	1	82.2
Medium-Voltage Dry-Type	2	86.1

DOE did not consider administrative costs for any of the non-regulatory policies in its analysis. Inclusion of such costs would decrease their NPV by a small amount.

17.2.3 Policy Interactions

DOE calculated the impacts of each regulatory policy separately from those of the other policies. In actual practice, certain policies are often most effective when implemented in combination to provide incentives. DOE attempted to make conservative assumptions to avoid double-counting policy impacts. Therefore, the policy impacts reported below are not additive; the combined impact of several or all of the policies may not be inferred from adding the results together.

Section 17.3 below presents the results of the analysis of the non-regulatory policies for distribution transformers.

17.3 NON-REGULATORY POLICY ASSUMPTIONS

17.3.1 No New Regulatory Action

The case in which no new regulatory action is taken with regard to distribution transformer efficiency constitutes the base case scenario described in chapter 10 of this TSD. This case defines the basis of comparison for all other scenarios. By definition, no new regulatory action yields zero energy savings and a net present value of zero dollars.

17.3.2 Financial Incentives Policies

DOE considered scenarios in which the Federal government would provide two types of financial incentives: rebates and tax credits. The government could provide consumers with a cash rebate at the time of purchase. Tax credits could be granted to consumers who purchased target-level distribution transformers, or the government could issue tax credits to manufacturers to offset costs associated with producing such equipment.

DOE's evaluation of financial incentive policies used a comprehensive study of the potential for energy efficiency in California performed by XENERGY, Inc., which summarizes experience with various utility rebate programs.[1] XENERGY developed a re-parameterized, mixed-source, information-diffusion model to estimate market impacts induced by financial incentives for energy-efficient appliances. The basic premise of this mixed-source model is that information diffusion drives technology adoption. The model is formulated to characterize the influences of both internal and external sources of information on consumer behavior by superimposing two components in the equation, each capturing the effect of one of two different types of information source. The effects of these two types of information-diffusion mechanisms are different. Internal sources of information influence consumers to purchase new products, due mainly to word-of-mouth from early adopters, while external information sources influence consumers to change their adoption decisions as a result of marketing efforts and information coming from outside the consumer group. The mixed-source model describes a combined impact of the two information-source types, and specific parameterization determines consumer adoption behavior. (Appendix RIA.A contains further details.)

XENERGY's model combined these two information diffusion mechanisms and generated a set of "implementation curves," which XENERGY calibrated using evaluation data from utility rebate programs conducted in the 1990s. Consumer response to rebate incentives appears to result from a combination of the two information-source types. The implementation curves illustrate the increased penetration of efficient equipment (i.e., increased market share) as a result of consumer response to benefit/cost (B/C) ratio changes induced by a specific rebate program. The implementation curves are used to depict various diffusion patterns based on perceived barriers to consumer purchase of high-efficiency equipment. There are implementation curves for varying levels of market barriers, from "no barriers" to "extremely high barriers." These curves provide a means to study the impact on the consumer participation rate of changing the B/C ratio by reducing the initial equipment cost through financial incentives.

To further understand the impacts of financial incentives policies, DOE used studies on forecasting the impact of consumer tax credits.[2,3] This research differentiated the impact of tax credits into the "direct price effect," which arises from the incremental equipment cost savings, and the "announcement effect," which is independent of the rebate amount. The announcement effect derives from the credibility that a particular technology receives from its inclusion in an incentive program, as well as changes in product marketing strategy and the resulting modifications in markups and pricing. DOE assumed that the direct price effect and the announcement effect would also apply to rebate programs. It assumed that half of the increases in market penetration associated with rebates would be due to the direct price effect and half to the announcement effect.

17.3.2.1 Consumer Rebates

DOE modeled the impact of the consumer rebate policy by determining the increase in market penetration of target-level equipment relative to the base case. It assumed that this policy would apply to low-voltage dry-type and medium-voltage dry-type transformers.

For low-voltage dry-type and medium-voltage dry-type transformers, DOE estimated the impact of increasing the B/C ratio via a rebate that paid 60 percent of the incremental equipment cost between a distribution transformer meeting the base case efficiency level and a unit meeting the target efficiency. DOE based the 60 percent rebate amount on existing utility rebate programs for low-voltage dry-type and medium-voltage dry-type transformers.[4–7] DOE studied each of these programs and found that the average rebate amounted to about 60 percent of the incremental equipment cost for low-voltage dry-type and medium-voltage dry-type transformers. It then assumed that the consumer rebate policy would reduce the incremental equipment costs for low-voltage dry-type and medium-voltage dry-type transformers during the analysis period by the same percentage.

DOE assumed the rebates would remain in effect until they had transformed the market, so that the shift in market share efficiencies seen in the first year of the program would be maintained throughout the forecast period (2016–2045). Section 17.3.2.1 below presents the results of the analysis for the consumer rebate policy.

To estimate the B/C ratios, DOE first calculated the B/C ratio for each design line with an efficiency meeting the target level relative to the base case design line with no rebate (see chapter 8 of this TSD for details on transformer design lines). It then calculated another B/C ratio for each design line meeting the target level, with a rebate reducing its incremental equipment cost, relative to the base case unit. Because of the incremental cost reduction due to the rebate, the B/C ratio for the rebate policy unit is larger. Table 17.3.1 shows the inputs to these calculations and the resulting B/C ratios for each design line (DL). See chapter 8 of this TSD for a detailed discussion of design lines.

Table 17.3.1 Benefit/Cost Ratios for Adopted Standard and Rebate Policy Cases

Design Line	Benefit (Lifetime Operation Cost Savings) ($)	Incremental Installed Costs ($)	B/C Ratio with No Rebate	Rebate Amount ($)	Incremental Equipment Cost after Rebate ($)	B/C Ratio for Rebate Policy Case
1	18	327	0.1	159	168	0.2
2	0	0	0.0	0	0	0.0
3	201	938	2.6	588	349	6.9
4	76	438	2.0	267	171	5.0
5	718	3,296	2.4	2228	1068	7.3
6	0	0	0.0	0	0	0.0
7	121	531	3.2	446	85	20.2
8	236	1,905	1.3	1164	740	3.3
9	53	139	6.1	96	43	20.0
10	472	3,958	1.2	2490	1468	3.3
11	129	1,342	0.8	878	464	2.2
12	701	6,042	1.1	4205	1837	3.8
13A	48	868	0.0	533	335	0.1
13B	758	9,337	0.5	6386	2951	1.6

Note: Design lines 1 though 5 represent liquid-immersed transformers. Design lines 6 though 8 represent low-voltage, dry-type transformers. Design lines 9 though 13B represent medium-voltage, dry-type transformers.

DOE then used the implementation curves discussed above to estimate the increased percentage of consumers who would purchase units that meet the policy target levels if given a rebate incentive. DOE assumed that medium-voltage dry-type transformers would fit the "moderate barriers" curve, since they are typically purchased by industrial entities that analyze the economics of the purchase and, therefore, have some incentive for energy efficiency.

Figure 17.3.1 shows an implementation curve with the penetration rates (market shares) of target-level units for an example design line of medium-voltage dry-type transformers as a function of B/C ratios. Using this method, DOE estimated that, for design line 12 (one of the medium-voltage, dry-type design lines), the penetration rate increase, as shown, would be about 24 percent.

To estimate the impacts of this rebate policy on medium-voltage dry-type transformers, DOE calculated the weighted average of the resulting market share increases by equipment class, using the market shares of the design lines. DOE applied these market share increases to the portion of shipments affected by the standards (non-compliant) in each equipment class, generating effective market share increases of distribution transformers meeting the target levels by equipment class. In the RIA model, DOE adjusted the base case shipments projection to reflect these percentage increases in effective market share.

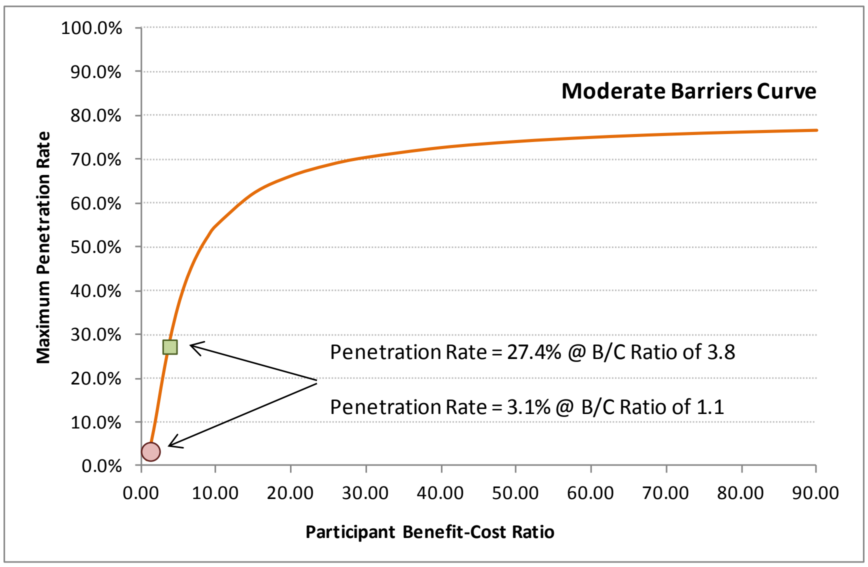

Figure 17.3.1 Market Penetration Curve for Design Line 12, Medium-Voltage Dry-Type Distribution Transformers

Table 17.3.2 lists the market share increases of the affected shipments, the percentage of the equipment class (EC) affected by the standards, and the effective EC market share increases, for each medium-voltage dry-type transformer equipment class.

Table 17.3.2 Market Share and Effective Market Share Increases for Consumer Rebates Policy Case by Low-Voltage, Dry-Type Equipment Class

Equipment Class	Increased Market Share (Percentage of Affected Market Segment) (%)	Percent Affected by Adopted Standard (%)	Increased Effective Market Share (%)
5	19.6	90.2	17.7
6	19.6	90.2	17.7
7	24.1	85.0	20.5
8	24.1	85.0	20.5
9	6.1	90.0	5.5

10	6.1	90.0	5.5

For low-voltage dry-type distribution transformers DOE assumed they would fit the "high barriers" curve. Low-voltage dry-type distribution transformers are typically purchased by industrial and commercial entities based on first cost.

Figure 17.3.2 shows an implementation curve with the penetration rates (market shares) of target-level units for an example design line of low-voltage dry-type transformers as a function of B/C ratios. Using this method, DOE estimated that, for design line 7 (one of the low-voltage, dry-type design lines), the penetration rate increase, as shown, would be about 56 percent.

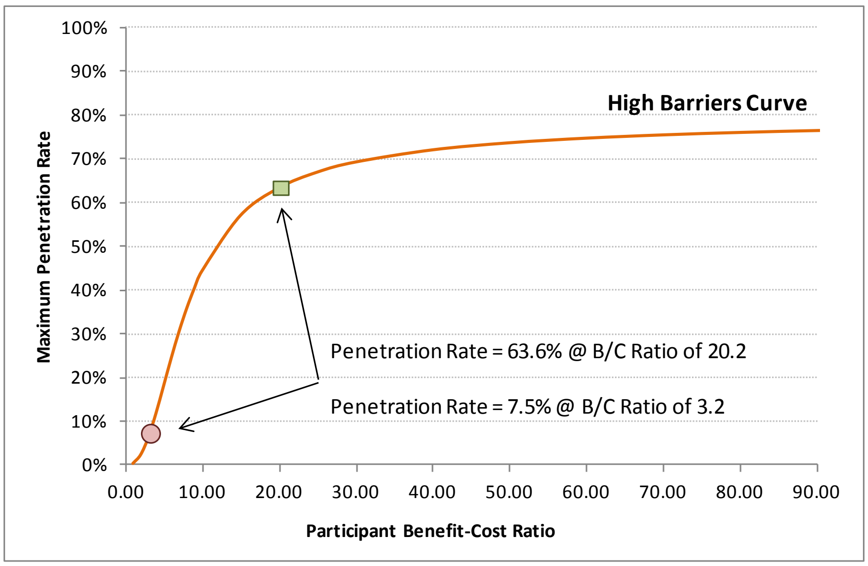

Figure 17.3.2 Market Penetration Curve for Design Line 7, Low-Voltage Dry-Type Distribution Transformers

Table 17.3.3 lists the market share increases of the affected shipments, the percentage of the equipment class (EC) affected by the standards, and the effective EC market share increases, for each low-voltage, dry-type transformer equipment class.

Table 17.3.3 Market Share and Effective Market Share Increases for Consumer Rebates Policy Case by Medium-Voltage, Dry-Type Equipment Class

Equipment Class	Increased Market Share (Percentage of Affected Market Segment) (%)	Percent Affected by Adopted Standard (%)	Increased Effective Market Share (%)
3	0.0	0.0	0.0
4	44.0	81.9	36.0

Although DOE assumed that the rebate policy would not apply to utilities, and therefore liquid-immersed transformers, it did analyze the impacts of consumer and manufacturer tax credits on liquid-immersed transformers. Therefore, DOE needed to calculate the impacts of a hypothetical rebate-type incentive for liquid-immersed transformers, assuming that such rebates would reduce the incremental installed cost of these transformers by the same percentage as they would for the medium-voltage, dry-type transformers. Using this assumption, DOE calculated the changes in B/C ratios for the liquid-immersed representative units, as shown above in Table 17.3.4.

DOE assumed liquid-immersed transformers would fit the "medium barriers" curve, because the utilities that purchase them usually evaluate the economics of the purchase. DOE acknowledges that utilities are increasing purchasing of first cost, in response to this DOE has increased the implementation rate to "medium barriers" from "low barriers" that was used in the previous 2007 rule.[8] In 1996, Oak Ridge National Laboratory (ORNL) stated in its determination analysis that 90 percent of the liquid-immersed transformer purchases were evaluated.[9] Data submitted by the National Electrical Manufacturers Association (NEMA) for years after 1996 showed that about 65 percent of utilities still evaluated their distribution transformer purchases.

For liquid-immersed transformers, DOE estimated the market-weighted averages of the penetration rates from the design line at the equipment class level. DOE then used implementation curves to estimate the increased percentage of consumers who would purchase units that meet the policy target levels, if given hypothetical rebates covering 60 percent of incremental costs. For example, as shown in Figure 17.3.3, for design line 5 the penetration rate (market share) would increase by approximately 33 percent. Table 17.3.4 lists the market share increases of the affected shipments, the percentage of the equipment class impacted by the adopted standards, and the effective equipment class market share increases, for each liquid-immersed transformer equipment class. DOE used these values to calculate the impacts of the tax credit policies on liquid-immersed transformers, as explained in the sections below.

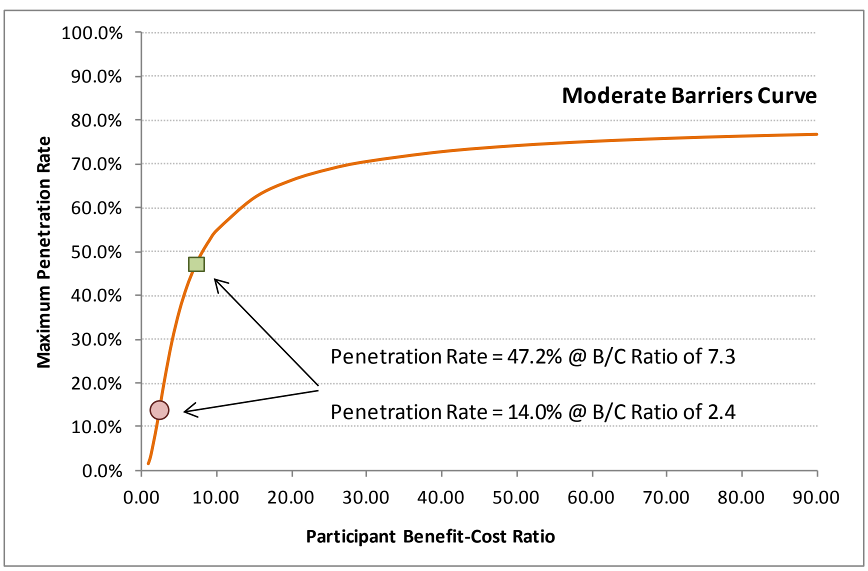

Figure 17.3.3 Market Penetration Curves for Design Line 5, Liquid-Immersed Distribution Transformers

Table 17.3.4 Market Share and Effective Market Share Increases for Consumer Rebates Policy Case by Liquid-Immersed Equipment Class

Equipment Class	Increased Market Share (Percentage of Affected Market Segment) (%)	Percent Affected by Adopted Standard (%)	Increased Effective Market Share (%)
1	0.0	27.3	0.0
2	20.2	70.1	11.3

17.3.2.2 Consumer Tax Credits

DOE assumed that a tax credit policy would apply to low-voltage dry-type, medium-voltage dry type transformers, as well as those liquid-immersed transformers that are purchased by investor-owned utilities (IOUs).

DOE assumed a consumer tax credit equivalent to the amount covered by rebates (i.e., 70 percent of the incremental cost between distribution transformer base case equipment and equipment meeting the policy target levels).

DOE estimated that, for all transformer types, the consumer participation rate would be lower than that for consumer rebates. Research on tax credits has shown that the time delay to the consumer in receiving a reimbursement via tax credit, plus the added transaction costs in tax-return preparation, make the tax credit incentive less effective than a rebate received at the time of purchase. Based on previous analysis,[888] DOE assumed that only 60 percent as many consumers would take advantage of the tax credit as would take advantage of a rebate.

Using a similar approach as for the rebate policy, DOE estimated that the market share of target efficiency distribution transformers would increase due to consumer tax credits over the base case by the percentages shown in Table 17.3.5. For all transformer types, these percentage market share increases are 60 percent of the market increases estimated for the rebate policy (which are shown in Table 17.3.2 through Table 17.3.4). For liquid-immersed transformers equipment classes 1 and 2, DOE adjusted the effective market shares to reflect the percentage of those transformers owned by IOUs, as shown in Table 17.3.6. DOE used data on transformer ownership by design line to estimate the percentage of liquid-immersed transformers owned by IOUs. Refer to chapter 8 of this TSD for more information.

DOE assumed the impact of this policy would be to permanently transform the market so that the shipment weighted efficiency gain seen in the first year of the program would be maintained throughout the forecast period. Section 17.3.2.3 below presents the results of the analysis for the consumer tax credit policy.

Table 17.3.5 Effective Market Share Increases for Consumer Tax Credits Policy Case by Equipment class

Equipment Class	Percent Owned by IOUs (%)	Increased Effective Market Share (Percentage of Equipment Class) (%)
1	72.0	0.0
2	80.0	6.8
3	72.0	0.0
4	35.0	21.6
5	0.0	10.6
6	0.0	10.6
7	0.0	12.3
8	0.0	12.3
9	0.0	3.3
10	0.0	3.3

17.3.2.3 Manufacturer Tax Credits

DOE assumed that tax credits could be given to manufacturers of liquid-immersed, low-voltage dry-type, and medium-voltage dry-type transformers. It assumed that this incentive policy would help reimburse manufacturers for retooling costs. Because these tax credits would go to manufacturers instead of consumers, DOE assumed that manufacturers would pass on the reduced costs, causing a direct price effect. However, DOE assumed that the announcement effect would not occur because the program would not be visible to owners of distribution transformers. Since the direct price effect is approximately equivalent to the announcement effect,[10] DOE assumed that half of the consumers assumed to take advantage of consumer tax credits would purchase more-efficient products with a manufacturer tax credit program. As a result, DOE estimated the percentage by which market shares of efficient distribution transformers would increase due to manufacturer tax credits over the base case, as shown in Table 17.3.6.

Table 17.3.6 Effective Market Share Increases for Manufacturer Tax Credits Policy Case by Equipment class

Equipment Class	**Increased Effective Market Share (Percentage of Equipment Class) (%)**
1	0.0
2	3.4
3	0.0
4	10.8
5	5.3
6	5.3
7	6.2
8	6.2
9	1.7

10	1.7

DOE assumed that the impact of this policy would be to permanently transform the market so that the shipment weighted efficiency gain seen in the first year of the program would be maintained throughout the forecast period.

17.3.3 Voluntary Energy-Efficiency Targets

DOE assumed that this policy would apply only to low-voltage, dry-type distribution transformers. For the RIA, DOE modeled the voluntary efficiency target policy assuming the EL3 efficiency level, which is also promoted by NEMA under its trademarked NEMA Premium[a]. The EL3 voluntary standard sets minimum energy-efficiency specifications for low-voltage dry-type. The EL3 efficiency standard is supported by various agencies that promote green building or by agencies that require LEED[b] certification for building retrofits or new construction.

The EL3 and NEMA Premium voluntary standards for low-voltage dry-type transformers are relatively new programs, because of this there is currently very little demand for the transformers. However, DOE assumed the impacts of these voluntary efficiency levels as a mature program and used the number of low-voltage transformers that met NEMA's TP1 at 9 percent an estimation of market share.

Table 17.3.7 Effective Market Share Increases for Voluntary Energy-Efficiency Targets by Equipment class

Equipment Class	Increased Effective Market Share (Percentage of Equipment Class) (%)
3	0.0
4	3.2

17.3.4 Early Replacement

Early replacement refers to the replacement of distribution transformers before the end of their useful lives. The purpose of this policy is to replace old, inefficient equipment with higher-efficiency units.

In 1995, ORNL performed a study of savings potential for early replacement of distribution transformers.[11] This study found that early replacement would be practical only at the time of routine transformer maintenance and would be cost-effective for just 13 percent of transformers as an alternative to refurbishment. As discussed in chapter 10 of this TSD, in

[a] http://www.nema.org/prod/pwr/trans/transformersProgram.cfm

[b] http://www.usgbc.org/DisplayPage.aspx?CMSPageID=64

discussions with DOE, transformer owners stated that refurbishment was uncommon in current practice. Thus, the RIA analysis assumed that owners would replace their transformers rather than refurbishing them. Therefore, DOE concluded that an early replacement policy for this equipment would have minimal impact and did not further analyze it.

17.3.5 Bulk Government Purchases

DOE assumed that this policy would apply only to low-voltage, dry-type distribution transformers. For the RIA, DOE assumed that a bulk government purchase policy would encourage Federal, State, and local governments to purchase distribution transformers meeting the target levels. Aggregating public sector demand could provide a market signal to manufacturers and vendors that some of their largest customers seek suppliers with products that meet an efficiency target at competitive prices. This program could also induce "market pull" impacts through the effects of manufacturers and vendors achieving economies of scale for high-efficiency products. DOE assumed that government agencies, such as the U.S. General Services Administration (GSA), would administer such a program. A bulk purchasing program could impact government purchases of low-voltage, dry-type transformers. However, while government entities own medium-voltage, dry-type and liquid-immersed transformers, they are typically purchased on a custom basis rather than for inventory. Thus, DOE concluded that a bulk purchasing program would not be appropriate for MV dry-type or liquid-immersed distribution transformers.

17.4 RESULTS SUMMARY FOR NON-REGULATORY ALTERNATIVES

Table 17.4.1 shows the NES and NPV of each of the applicable non-regulatory alternatives. The results are reported for liquid-immersed and medium-voltage, dry-type transformers, as well as in total. The case in which no regulatory action is taken with regard to distribution transformers constitutes the base case (or "No Action") scenario. Since this is the base case, energy savings and NPV are zero by definition. For comparison, the table includes the impacts of the adopted energy conservation standards. The NPV amounts shown in Table 17.4.1refer to the NPV based on two discount rates (seven percent and three percent real). Note that, for three of the policy alternatives, no results are reported; as discussed above, DOE found that those policies would not impact the distribution transformers covered by this energy conservation standard.

None of the alternatives DOE examined would save as much energy or have an NPV as high as the adopted standards. Also, several of the alternatives would require new enabling legislation, such as consumer or manufacturer tax credits, since authority to carry out those alternatives does not presently exist.

Table 17.4.1 Non-Regulatory Alternatives and the Adopted Standard

Policy Alternatives	Type	Primary Energy Savings(quads)	Net Present Value*(billion $2006)	
			3 discount rate	7 discount rate
No New Regulatory Action		0.0	0.0	0.0
Consumer Rebates	Liquid	0.0	0.0	0.0
	LV** Dry	0.336	2.409	0.627
	MV***Dry	0.024	0.131	0.025
	Total	0.36	2.54	0.65
Consumer Tax Credits	Liquid	0.08	0.26	0.07
	LV Dry	0.20	1.445	0.376
	MV Dry	0.015	0.08	0.015
	Total	0.361	2.54	0.65
Manufacturer Tax Credits	Liquid	0.01	0.13	0.03
	LV Dry	0.10	0.723	0.188
	MV Dry	0.007	0.039	0.007
	Total	0.12	0.89	0.23
Voluntary Energy-Efficiency Targets	Liquid	0.0	0.0	0.0
	LV Dry	0.03	0.217	0.056
	MV Dry	0.0	0.0	0.0
	Total	0.03	0.217	0.056
Bulk Government Purchases	Liquid	0.0	0.0	0.0
	LV Dry	0.154	0.911	0.284
	MV Dry	0.0	0.0	0.0
	Total	0.154	0.911	0.284
Adopted Standards	Liquid	0.366	3.66	0.749
	LV Dry	1.091	7.81	2.034
	MV Dry	0.126	0.673	0.126
	Total	1.58	12.14	2.909

* DOE determined the NPV discounted to 2010 in billion 2010$.
** LV = low-voltage
*** MV = medium-voltage

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APPENDIX 3A. CORE STEEL MARKET ANALYSIS

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APPENDIX 3A. CORE STEEL MARKET ANALYSIS

Core steel is one of the major cost drivers of a distribution transformer and is fundamentally linked to the efficiency of the finished transformer. When looking at the impact of energy conservation standards on the distribution transformer industry, it is therefore important to understand the core steel market.

Starting in late 2003, transformer manufacturers began to experience increases in the price of core steel. While prices vary across the industry (i.e., generally based on the volume of an order and negotiated contracts), some manufacturers witnessed approximately a doubling in the core steel prices in 2005, as compared with 2002. The price continued to increase through 2007 until the effects of the U.S. financial crisis began to propagate throughout the global economy causing a significant drop in steel prices.

During the Department of Energy's (DOE) previous rulemaking on distribution transformers, spanning from 2000 to 2007, DOE received comments about the rapid increase in core steel prices. The two main issues raised were: 1) the cost-effectiveness of higher standards given higher core steel prices, and 2) the availability of sufficient quantities of higher grade steels needed to manufacture more efficient transformers.

For the current rulemaking on distribution transformers, manufacturers commented during interviews for the preliminary analysis and NOPR that core steel prices and core steel availability remain a major concern in the industry.

To address these comments and concerns, DOE studied the electrical core steel market in detail. In conducting this study, DOE reviewed publicly available reports, press releases, and articles pertaining to both the steel industry and the global core steel market. DOE also consulted with U.S. core steel manufacturers, several core steel processing companies, and transformer manufacturers. Additionally, during the stakeholder negotiations, several stakeholders offered valuable data and insight into the market to help redress these issues.

Nearly all manufacturers in all three superclasses indicated that higher standard levels would likely result in greater demand for higher grades of core steel, some of which have a limited global supply. In response, DOE updated its previous study on the core steel market. Additionally, DOE examined material price sensitivities to understand how fluctuating material prices might impact the cost effectiveness of the standard levels being considered (see Appendix 5C).

Section 3A.1 of this appendix provides background on the U.S. and international core steel markets and U.S. import/export data. Section 3A.2 describes the current global core steel market. Section 3A.3 presents U.S. electrical steel pricing data and a description of the pricing, supply, and suppliers of amorphous metal. Finally, Section 3A.4 provides brief company profiles of the major global core steel manufacturers.

3A.1 **OVERVIEW**

Energy-efficient, grain oriented electrical steel is a unique product. It has a high silicon content, which complicates its manufacture. It has to be carefully processed, rolled to the correct thickness, and heated and cooled at controlled rates to facilitate the growth of steel grains. According to the World Steel Association, about 8.7 million metric tons ("tonnes") of electrical steel were produced globally in 2009[1], Estimates from experts in the steel industry suggest that, of the total electrical steel production in 2009, 2.5 million tonnes were for grain oriented electrical steel.[2] It is a highly specialized niche market product that is essential for the production of distribution transformers.

3A.1.1 **Overall U.S. Steel Market History**

Extreme volatility has characterized the U.S. steel market over the last three decades. During the 1980s and the 1990s, mills were closed, and producers reduced their workforce and capacity, while investing in new steel processing technologies. This restructuring resulted in productivity increases, with the U.S. emerging as a world leader in low cost steel production. Prosperity in the steel industry continued through 1996 as capacity and demand increased.

However, in 1997 the steel market began to change as imports increased to meet the growing U.S. demand. Steel imports increased seven percent from 1996 to 1997, in part due to the relative strength of the dollar in the late 1990s.[3] In 1998 the change was noticed as hot rolled steel imports increased by 70 percent, prices dropped nearly 20 percent, capacity utilization rates decreased to 75 percent, and six steel companies declared bankruptcy.[4] The "1998 steel import crisis" was caused in part by the Asian financial crisis that began in 1997, in which the currencies of several countries plummeted, in concert with sharp declines in steel consumption in these countries.[3]

The years 1998, 1999, and 2000 were the three highest import years in U.S. steel history at the time, which drove down prices. Imports for several major product lines, including rebar, coiled plates, and cold rolled steel, continued to increase and some U.S. producers were forced to declare bankruptcy. The high value of the U.S. dollar during that time period contributed to the crisis.

From 2000 to 2007, the U.S. steel market, and more specifically the US electrical steel market, began to experience pressure from several other directions. The demand in China and India for high-efficiency, grain oriented core steel limited availability to the rest of the world and drove up prices. Combined with cost-cutting programs and technical innovation at their respective facilities, the lower value of the U.S. dollar enabled domestic core steel suppliers to become globally competitive exporters.

In late 2007, the U.S. steel market began to decline with the onset of the global economic crisis. U.S. steel manufacturing dropped to nearly 50 percent of production capacity in 2009 from almost 90 percent in 2008. Only in China and India did the production and use of electrical grade steel increase for 2009.[5] In 2010, the price of steel began to recover. However, it was more a reflection of the continually increasing cost of material inputs, such as iron ore and coking coal, than a definite market recovery. Then again, in 2011, core steel prices fell rather dramatically.

3A.1.2 U.S. Electrical Steel Market Key Players

There are two domestic manufacturers of grain oriented electrical steels, AK Steel and Allegheny Ludlum. Both companies produce grain oriented electrical steel for domestic use and export. As DOE understands it, AK Steel is the only domestic producer of non-oriented electrical steel, sometimes used in low-cost stacked cores. AK Steel is also the only domestic producer of high permeability, domain-refined (laser-scribed) core steel, used in high-efficiency stacked cores.

AK Steel, founded in 1899 and headquartered in Middletown, Ohio, employs approximately 6,600 people in Ohio, Kentucky, Indiana, and Pennsylvania. With $6 billion in sales in 2010, the company produces flat rolled carbon, stainless, and electrical steel products. AK Steel produces a range of electrical steels, including grain oriented steel grades of M2, M3, M4, M5 and M6, non-oriented standard steel grades of M15 to M47, high-permeability steels, and domain refined, laser scribed steels, H-0 DR, H-1 DR, and H-2 DR.[6]

Allegheny Ludlum Corporation, headquartered in Pittsburgh, PA, operates specialty metals manufacturing facilities in Pennsylvania, Connecticut, Massachusetts, Indiana, and Ohio. Allegheny Ludlum employs approximately 2,550 people, and in addition to its other stainless and specialty steel products, produces grain oriented steel with grades from M2 to M6.[7]

Hitachi Metglas, headquartered in Tokyo, Japan, is the major global supplier of amorphous ribbon. While not owned by a U.S. company, the company operates a U.S. plant in Conway, South Carolina, with an annual capacity of more than 40,000 tonnes. The only other known supplier of amorphous metal is based in China and currently only serves the Chinese market.

Other key players in the U.S. core steel market include core steel wholesalers and processors. National Materials LP, an electrical steel processing and distribution company, has locations in Pennsylvania, Illinois, California, Michigan, and Mexico, and provides U.S. transformer manufacturers with both grain oriented and non-oriented slit core steel. The Tempel Steel Company, located in Chicago, Illinois, produces shunt and cut core sections and E-I laminations. The Ontario, Canada plant of Cogent Power, Inc., a joint venture between two international steel manufacturers, produces finished wound and stacked transformer cores and slits core steel for U.S. transformer manufacturers. Lastly, LakeView Metals Inc., based in Illinois, supplies non-oriented, grain oriented, and amorphous electrical steel products.

3A.1.3 International Electrical Steel Market Key Players

In addition to the two domestic producers, AK Steel and Allegheny Ludlum, there are currently eleven major international companies producing grain oriented electrical steel. These companies and their estimated installed capacity for grain oriented electrical steel output are listed in Table 3.1. Note that the capacities of these firms significantly depend on the mix of steels they produce. All else equal, a production mix weighted towards higher grade steel slows throughput relative to lower-grade steels. Therefore, it should not be inferred from the outputs listed below that the companies have the ability to produce any grade of steel at that level. Note also that all of these companies, except Allegheny Ludlum, also offer non-oriented electrical steels.

Table 3.1 Grain Oriented Electrical Steel Key Players

Company	**Country**	**Estimated Installed Capacity for Grain Oriented Steel (2011-2014)[a] [1,000 metric tons]**
Wuhan Iron and Steel Company (WISCO)	China	440
Novolipetsk Steel (NLMK)	Russia	344
AK Steel	United States of America	312
Thyssen Krupp Electrical Steel (TKS)	Germany, France, India	250
The Pohang Iron and Steel Company (POSCO)	South Korea	250
Nippon Steel Corporation (NSC)	Japan	243
JFE Steel Corporation	Japan	160
Allegheny Ludlum (ATI)	United States of America	109
ArcelorMittal	Brazil, Czech Republic	107
Orb (Tata Steel, Cogent Power)	United Kingdom	90
Baosteel Group Corporation	China	90
Stalprodukt S.A.	Poland	62
Hitachi Metglas	Japan (with U.S. production)	106
Angang Steel	China	100

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Nippon Steel produces eight types (each with several grades) of grain-oriented electrical steel and five types of non-oriented electrical steel. JFE Steel produces nine types (each with several grades) of grain-oriented electrical steel and six types of non-oriented electrical steel. Novolipetsk has an annual capacity of 350,000 tonnes of electrical steel, including grain oriented and non-grain oriented steel.[8] Wuhan has an annual capacity of 2 million tonnes of electrical steel, making it the largest electrical steel production base in the world. ThyssenKrupp Electrical Steel (TKES) produces grain-oriented steel, while ThyssenKrupp Stahl AG produces non-oriented electrical steel grades. See section 3A.4 at the end of this document for brief profiles on each of these players in the core steel market.

[a] Estimates are based on AK Steel's "Comments on the Global Supply of Grain Oriented Electrical Steels" and industry research conducted by DOE.

3A.1.4 U.S. Import/Export Data

Since the import crisis of 1998, the Federal government has monitored steel imports more closely. The Steel Import Monitoring and Analysis (SIMA) System was established in 2003 and reports amounts and types of steels being imported and exported monthly and annually.[b]

From 2008 to 2009, imports of electrical steel fell from 110,000 tonnes to 60,000 tonnes, nearly a 50 percent reduction. This decline represents the continuing effects of the economic crisis beginning in 2008. The Specialty Steel Industry of North America, a trade association based in Washington, D.C., reports that the U.S. consumption of electrical grade steel was approximately 198,500 tons in 2009, a 43 percent decrease from the 2008 figure of 345,000.[9] However, from 2009 to 2010, imports of electrical steel rose from 65,600 tonnes to 94,300 tonnes, indicating nearly a 44 percent increase. This increase indicates the recovery of the steel industry from the economic crisis. The U.S. consumption total includes core steel for more equipment than simply distribution transformers.

On the exporting side, the U.S. shipped 212,600 tonnes of electrical grade steel outside its borders in 2010, compared to 205,000 tonnes in 2009. In 2006, China and India imported about 13 percent of U.S. exported electrical steel while Canada and Mexico together imported nearly 50 percent. In 2010, China's and India's imports of U.S. electrical steel increased to about 21 percent while imports in Canada and Mexico decreased to about 32 percent of the total U.S. exports of electrical steel.[10]

3A.2 CURRENT GLOBAL ELECTRICAL STEEL MARKET

DOE was informed by a range of experts that the prices of core steel have been volatile over the time period from 2006 to 2011. Since peaking in 2008, prices first fell rapidly in 2009, then recovered in 2010, before dropping again in 2011. Several market forces have contributed to steel price volatility to varying degrees over this time period. These trends are primarily due to five factors:

1. Persistent high global demand for grain oriented electrical steel, particularly in China and India;
2. Generally higher raw material prices to the core steel manufacturers (e.g., iron ore, coking coal, scrap steel) and higher processing energy costs;
3. The low value of the U.S. dollar, (low value increases the cost of imported steel and encourages domestic suppliers to export); and
4. The onset of the global economic recession and financial meltdown in late 2007, and, in the US market, a sharp decline in new building construction that has yet to turn around.

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[b] The U .S. Department of Commerce - International Trade Administration's Steel Import Monitoring and Analysis System is available online at <www.ia.ita.doc.gov/steel/license>.

These factors are discussed in the following sections.

3A.2.1 **Asian Steel Consumption**

Over the past decade, Asia's demand for electrical steel has grown tremendously. It is the only region in the world that increased consumption of electrical steel from 2008 to 2009. In particular, the countries of China and India, with economic growth rates of 9.1 percent and 7.4 percent, respectively, have both become large producers and importers of electrical steel as they expand their electrical grids. [11]

China became the largest steel consumer in the world when it surpassed the consumption of the United States and Japan combined in 2003.[12] Since then, between 2004 and 2010, Chinese steel consumption more than doubled, further increasing from 276 million tonnes to around 576 million tonnes, a 109 percent increase.[13] Electrical steel is of great importance in China, due to the country's increasing energy consumption attendant to its rapid real economic growth. Not only is China putting new transformers into use, they are also replacing older transformers to improve grid reliability. China is seeking higher efficiency, grain oriented steels to reduce energy losses. Construction of a highly efficient grid will offset some of China's need for generation capacity. The persistent growth in Chinese demand offset some of the downward pressures on electrical steel prices during the global recession.

Steel consumption has also increased rapidly in India since 2004, during which time consumption increased about 72 percent.[13] The World Steel Association forecasts that steel demand in India will increase to nearly 72 million tonnes of finished steel product by 2011 making India the third largest consumer.[14]

3A.2.2 **Core Steel Manufacturer Input Prices**

A shortage of raw materials for making steel, particularly iron ore, is contributing to the price increases. Production of iron ore fell in 2009 for the first time in seven years due to the global recession. However, prices remained high due to record level trading, which was up 7.4 percent from the previous year. The increase in trading was the result of higher Chinese imports, driven by growing demand, combined with a fall in Chinese domestic production.[15] China used to be the world´s largest producer of iron ore, but now due to the exhaustion of its domestic resources, it occupies fourth place after Australia, Brazil, and India.

In 2009, worldwide production of iron ore fell by 6.2 percent to 1.59 billion tons.[15] Three companies supply approximately 35 percent of the world’s iron ore: Brazil's Companhia Vale do Rio Doce SA (CVRD) and the Anglo Australian companies in Australia: Rio Tinto and BHP Billiton. In the past, China entered into long term supply contracts with mining companies that supply these raw materials to secure sufficient quantities of iron ore for its growing economy. However, in 2010 these three suppliers stopped using annual iron ore benchmark prices and turned to more flexible index-based pricing, bringing even more volatility to the market.[16]

Coke is another raw material needed for steel production that is in short supply. Coke is used to produce about 66 percent of steel worldwide. Within the U.S., the domestic steel depression has caused the closing of many coke production sites. Additionally, U.S. exports of coke have increased, as nearly two thirds of all U.S. coking coal was exported in 2009. China, a large producer of coke, has decided to keep much of this material within its borders, while also increasing imports to meet its growing steel production demand. China imported 34 million tonnes of coking coal in 2009, which is almost a fivefold increase over 2008.[17] These factors have contributed to a rise in coke prices from $129 per ton in 2009 to over $200 per ton in 2010.[18]

An alternative method to using iron ore and coke to fabricate steel is the use of steel scrap. However, in recent years the availability of steel scrap in the United States has continually declined. Despite a worldwide decline in steel production, U.S. scrap exports continued to increase, and in 2009, the United States exported nearly one-third of all the scrap it produced. Scrap exports in 2009 were 46.7 percent of domestic scrap consumption, compared to only 32.6 percent in 2008, and less than 20 percent in 2005.

China is the overwhelming beneficiary of the increase, as U.S. scrap exports to China have more than doubled, even though both U.S. and global steel production fell sharply. Scrap prices peaked in the middle of 2008, before falling sharply. However, by December 2008 the price began to rise and has continued to move sharply upwards through 2010. The American Metal Market (AMM) price for shredded auto scrap in March 2010 was $350 per ton, while the price for "#1 busheling" was $443.75. Figure 3.1 illustrates the volatility in U.S. scrap prices over the past two years.[19]

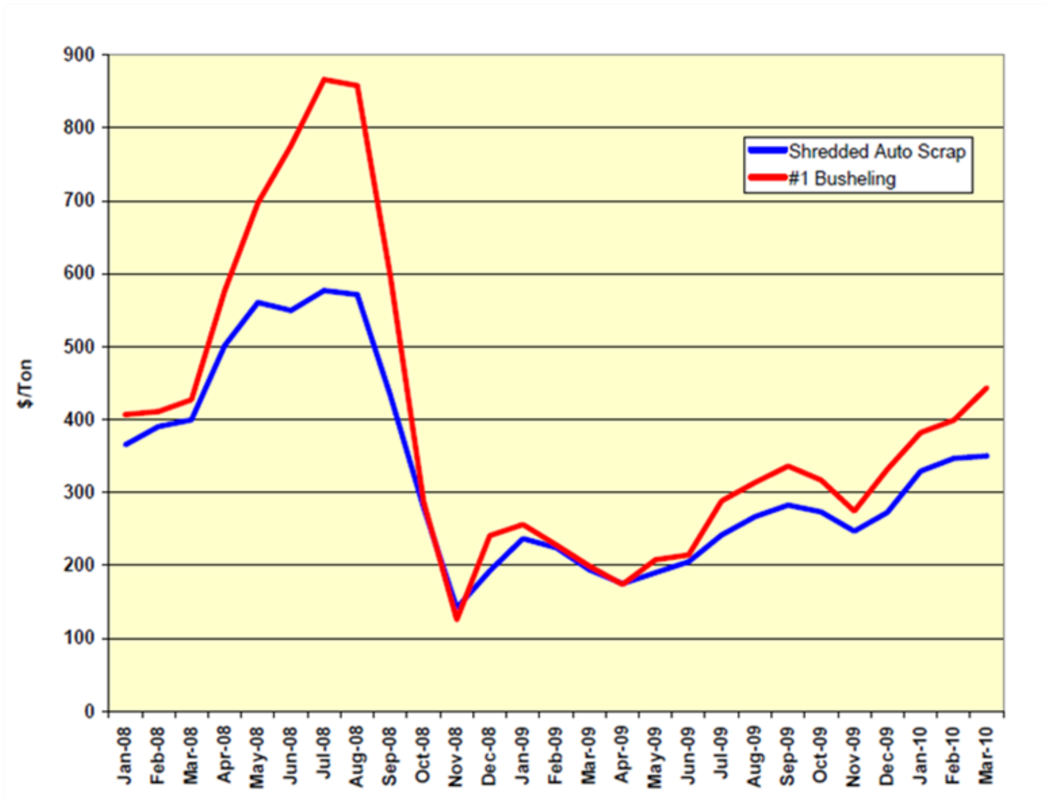

Figure 3.1 Price of Steel Scrap in the U.S. ($/Ton)
Source: American Metal Market, www.amm.com

These rising raw material prices, in conjunction with high energy prices, have caused large U.S. steel producers to place surcharges on core steel. U.S. electrical steel manufacturers say these surcharges are needed to protect against raw material and energy cost fluctuations. Table 3.2 presents the January 2009–December 2010 electrical steel surcharges implemented by Allegheny Ludlum and AK Steel. Each month these surcharges are adjusted based on the prices of raw materials and energy used to manufacture the products.

Table 3.2 Alloy Surcharge for Electrical Steels (US$/ton)

2009	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Allegheny Ludlum	207	321	299	227	205	156	168	181	245	266	268	288
AK Steel	10	165	165	100	55	10	70	75	170	185	210	185
2010	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Allegheny Ludlum	279	309	385	391	446	462	485	469	458	433	409	384
AK Steel	155	235	325	330	420	435	395	385	350	350	350	285
2011	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Allegheny Ludlum	373	427	485	503	492	515	520	529	532	534	521	508
AK Steel	290	350	430	400	390	435	440	455	460	460	450	450

Source: AK Steel and Allegheny Ludlum press releases.

These surcharges decreased severely in 2009 due to the global economic crisis, but have increased in 2010 due to greater market activity and higher raw material prices.

3A.2.3 **Value of the U.S. Dollar**

The value of the U.S. dollar has dropped in recent years against other currencies, affecting the U.S. core steel market. As the value of the dollar declines, the cost of imported core steel paid by domestic transformer manufacturers increases. The cost of raw materials, particularly scrap, to domestic steel manufacturers also increases, creating higher steel prices. Conversely, core steel produced in the U.S. becomes an attractive export, since its cost to foreign consumers is lower. These factors drive up core steel prices paid by U.S. transformer manufacturers.

Table 3.3 illustrates the decrease in value of the U.S. dollar between 2009 and 2011. The currency conversion rates are provided with those of several other countries.

Table 3.3 Selected International Currency Rates per U.S. Dollar

1 Unit / USD			
Currency	**Average 2009**	**Average 2011**	**Percent Change [%]**
Euro	0.719	0.767	6.68%
Chinese Yuan	6.841	6.344	-7.27%
Japanese Yen	93.617	77.68	-17.02%
Indian Rupee	48.850	54.074	10.69%
Russian Rouble	31.815	31.471	-1.08%
Canadian Dollar	1.142	1.021	-10.60%
South Korean Won	1279.077	1153.46	-9.82%
British Pound	0.641	0.643	0.31%

Source: The OANDA online historical exchange rates, http://www.oanda.com/currency/historical-rates.

3A.2.4 Global Economic Recession

The lingering effects of the recent U.S. recession and financial crisis continue to affect the electrical steel market. In 2008, real demand for core steel began shrinking. However, global steel prices were increasing rapidly as a result of volatile input costs and higher energy and transport charges. Due to the rising price, companies were only purchasing for their immediate requirements and producers were keeping inventory levels at a minimum, which significantly reduced the demand for steel products, such as core steel.[20] In October of 2008 the weakening economies of the U.S. and the European Union (EU) had sufficiently halted demand for steel causing the global price of steel to plummet.[21]

The global crisis had badly affected export business and major steel companies made significant cuts in production to try to stabilize the situation. Steelmakers introduced major production cuts, reducing output to nearly 40 percent of capacity. These combined effects caused the global steel price to decline in late 2008 through 2009.[22] Still, other companies like Angang Steel were developing facilities for expanded electrical steel production.

3A.3 U.S. ELECTRICAL STEEL PRICING

3A.3.1 U.S. Electrical Steel Producers

AK Steel

AK Steel's annual report gives insight into the outlook of the domestic steel market. In 2010, AK Steel shipped 5.7 million tons of steel, an increase of 44 percent over 2009 figures.[23] Although sales did not fully return to pre-recession levels and the majority of this steel is not grain-oriented electrical steel, this overall increase signaled a recovery from the trough of the economic cycle.

AK Steel continues to apply surcharges to steel prices to mitigate the impacts of fluctuating raw material and energy costs, and these surcharges were increased in 2010 in order to cover higher raw material costs. While AK Steel previously made many long-term contracts with fixed selling prices, almost 90 percent of current contracts now implement price surcharges.

AK Steel noted that many domestic and foreign steel manufacturers were increasing their production capacity and expected sales to the United States. In particular, Chinese steel manufacturers have increased production capacity in recent years. As a result, the global price of steel could decline if supply outpaces demand.

Allegheny Ludlum

Allegheny Ludlum expressed a strategic focus on high value specialty steels like grain oriented electrical steel. During 2010, sales of high value steels represented 70 percent of its total sales compared to 42 percent of sales in 2002. Similar to AK Steel, Allegheny Ludlum mitigated variable material prices by releasing monthly surcharges for the price of electrical steel.[24]

3A.3.2 **Steel Pricing**

Since demand began increasing relative to supply in late 2003, steel prices, including grain oriented electrical steel, started to increase. In 2005, prices of other types of steel started to decrease, but those of grain oriented electrical steels did not. Prices continued to increase through 2008, when they fell sharply as a result of the global economic recession. This reduction in core steel prices was somewhat offset by increasing demand from China and India. Prices began to stabilize in 2010, but then fell again in 2011, in part due to continued weakness in the U.S. housing market.

It is important to note that, while made from the same raw materials, the prices of electrical steel do not necessarily follow general steel market trends.

3A.3.3 **U.S. Electrical Steel Pricing**

DOE contracted Optimized Program Service, Inc. (OPS) to develop material price estimates for the engineering analysis. OPS used data from their own records as well as data provided by transformer manufacturers and material suppliers and wholesalers. Although not all U.S. transformer manufacturers pay the same amount per pound for electrical-grade steels due to varied contract negotiations, these prices are intended to be representative of a standard quantity order for a medium to large scale U.S. transformer manufacturer. DOE then refined these price estimates through conversations with transformer manufacturers in 2010 and 2011. Figure 3.2 illustrates the five-year price trend for grain oriented steels.

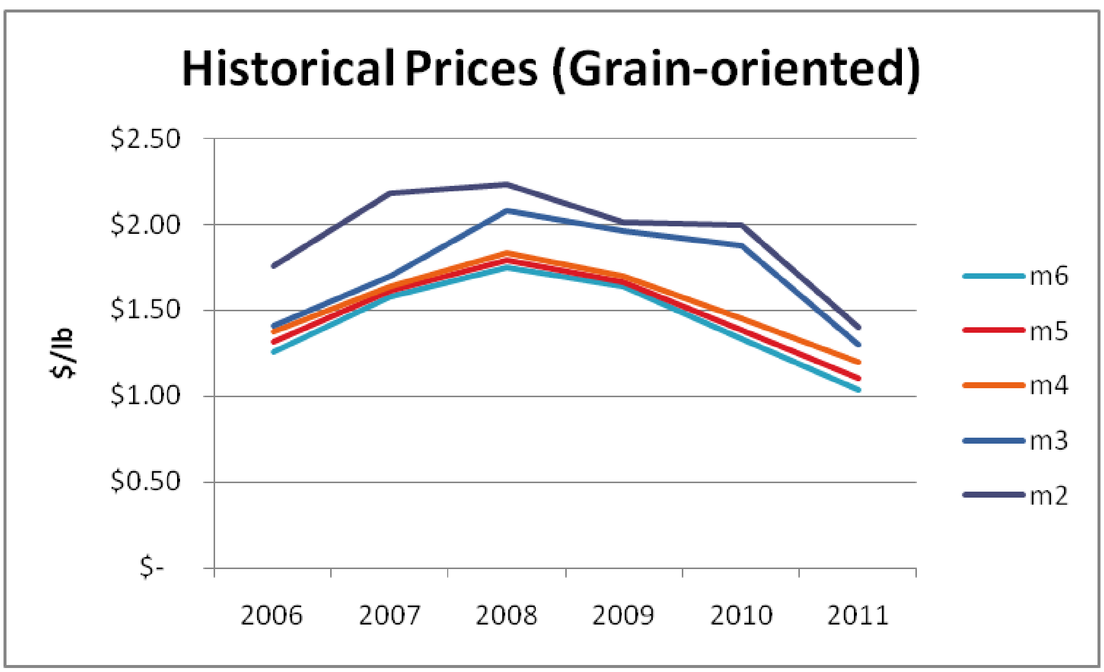

Figure 3.2 Average Annual Prices for Grain-Oriented Steels in the US (2010$/lb)

The engineering analysis also examined three types of specialty electrical steels: ZDMH, SA1, and H-0 DR. ZDMH—mechanically scribed, deep domain-refined core steel—is a patented product manufactured by Nippon Steel Corporation in Japan. The domain refinement is able to survive the annealing furnace; therefore, this steel is used for highly efficient wound cores. However, it has very limited use in the U.S. because of supply limitation. SA1, Metglas[c] amorphous material, is highly efficient and is also used in wound-core configurations. H-0 DR and H-1 DR, the most efficient steels used in stacked core configurations, are manufactured domestically by AK Steel. H-0 DR undergoes a laser scribing process that decreases the losses associated with the steel by as much as 10 percent.[25] Figure 3.3 illustrates the historical price trends of these steels from 2006 to 2011. Note that the amorphous material (SA1) represents the cost per pound of a finished core, while the other two steels represent the raw material price. Additionally, DOE only considered the amorphous price from 2008 to 2010 because this is when North American amorphous core manufacturers began production. DOE believes the price of core production by foreign manufacturers prior to 2008 is no longer representative of the current price for amorphous cores in North America.

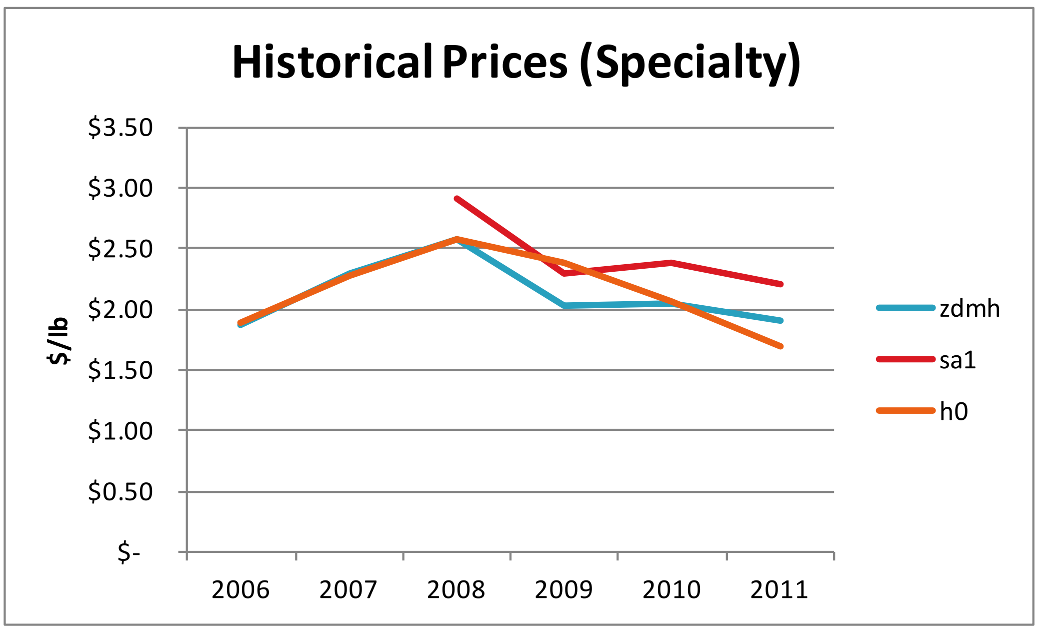

Figure 3.3 Average Annual Prices for Specialty Steels in the US (2010$/lb, note: SA1 is finished core)

3A.3.4 **Amorphous Core Material**

Amorphous core material has been in existence for more than 35 years. Hitachi Metals is the only global supplier of the material. While Hitachi Metals is based in Japan, it also has a

[c] Registered trademark of Metglas, Inc., a wholly owned subsidiary of Hitachi Metals, Ltd., Tokyo, Japan.

facility in the United States where amorphous metal is produced. Hitachi sells the material in the United States through a wholly-owned subsidiary called Metglas®. This U.S. facility currently has three production lines, and can produce approximately 46,000 tonnes of amorphous steel per year. The Hitachi facility in Japan has four production lines, and can produce 60,000 tonnes per year.

In addition to Hitachi Metals, one other supplier is known to be producing amorphous metal commercially. A company based in China called Advanced Technology & Materials (AT&M) has production capacity of 40,000 tonnes per year, which is expected to increase to 100,000 tonnes per year by 2013.[26] This company is not considered a global supplier, however, because it is not known to supply amorphous metal outside the Chinese market. Additionally, several transformer manufacturers have called into question the quality of amorphous metal this company produces. Several other companies have attempted to produce amorphous metal in recent years, but none are known to be supplying the marketplace.

Therefore, the current total global capacity for amorphous metal is 146,000 tonnes per year, of which 40,000 tonnes are exclusively available to the Chinese marketplace. The remaining 106,000 tonnes are sold in the global marketplace. Compared to the 2.5 million tonnes of grain-oriented electrical steel produced in 2009, amorphous metal constitutes about 4 percent of the global supply for electrical steel.

3A.3.5 Material Price Sensitivity Analysis

DOE considered material prices from 2006-2011 (in constant 2010$) in its analysis, and used the 2010 material prices as the reference case for its analysis. Many manufacturers and suppliers of core steel indicated that the 2010 price was indicative of the expected material prices for the next several years. They did not expect material prices to rise back to the highs seen in 2008 for the near future, and identified 2008 as a maximum material price scenario. DOE examined a material price sensitivity based on 2008 prices and 2006 prices as the high price and low price scenarios, respectively. Detail on these sensitivities and the specific material prices can be found in appendix 5C.

3A.4 ELECTRICAL STEEL MANUFACTURER PROFILES

3A.4.1 AK Steel

AK Steel, founded in 1899 and headquartered in Middletown, Ohio, employs about 6,600 people in Ohio, Kentucky, Indiana, and Pennsylvania.[27] With $6 billion in sales in 2010, the company produces flat rolled carbon, stainless, and electrical steel products. AK Steel produces a range of electrical steels, including oriented steel grades of M2, M3, M4, M5, and M6, non-oriented standard steel grades of M15 to M47, and domain-refined, laser scribed steels, H-0 DR, H-1 DR, and H-2 DR. In 2009, AK Steel produced 312,000 tonnes of grain oriented electrical steel.[2]

3A.4.2 Allegheny Ludlum

Allegheny Ludlum Corporation, headquartered in Pittsburgh, PA operates specialty metals manufacturing facilities in Pennsylvania, Connecticut, Massachusetts, Indiana, and Ohio. In 2009, Allegheny Ludlum had revenue of approximately $3.1 billion. In addition to its other stainless and specialty steel products, it produces grain oriented steel with grades from M2 to M6. In 2009, Allegheny Ludlum produced 109,000 tonnes of grain oriented electrical steel.[2]

3A.4.3 Nippon Steel Corporation

In 1970, Yawata Iron and Steel and Fuji Steel merged to form Nippon Steel Corporation. Located in Tokyo, Japan, Nippon Steel has about 15,800 employees and produces almost 30 million metric tons of crude steel annually.[28] Nippon produces grain oriented steel with grades from M2 to M6 and non-oriented standard steel grades of M15 to M45. In 2009, Nippon Steel produced 243,000 tonnes of grain oriented electrical steel.[2]

In 2009, 20 percent of Nippon Steel's exports went to China, while 60 percent were distributed among other Asian regions, 5 percent to North America, 4 percent to South America, and 2 percent to Europe. The remaining 9 percent were disbursed between Africa, the Middle East, and Oceania.[29]

3A.4.4 JFE Steel Corporation

Another Japanese company, JFE Steel Corporation, was formed in December 2001 from a merger between Kawasaki Steel and NKK Corporation. It produced a total of 29.3 million tonnes of crude steel in 2008. JFE Steel produces several types (each with several grades) of grain oriented electrical steel and non-oriented electrical steel. In 2009, JFE Steel Corporation produced 160,000 tonnes of grain oriented electrical steel.[2]

3A.4.5 Novolipetsk Metallurgical Plant

Novolipetsk Steel (NLMK) started in 1931 when iron ore and limestone deposits were discovered in Lipetsk, Russia. NLMK is now the largest steel sheet producer in Russia, and produced over 11 million metric tons of crude steel in 2010.[30] In 2006 it acquired Viz Stal Metallurgical Plant, which was the largest producer of grain oriented steel and the second largest electrical steel producer in Russia.[31]

NLMK’s share of global grain oriented electrical steel production is nearly 11 percent and over 80 percent of its products are exported. In 2007, it produced 189,000 tonnes of grain oriented steel and 19,000 tonnes of non-grain oriented steel.[32] In 2009, NLMK produced 344,000 tonnes of grain oriented electrical steel.[2] NLMK’s total transformer steel production capacity is approximately 350,000 tonnes annually.[33]

3A.4.6 **Hitachi Metglas**

Hitachi Metglas, headquartered in Tokyo, Japan, is the major global supplier of amorphous ribbon. The company operates a U.S. plant in South Carolina, with an annual capacity of more than 40,000 tonnes. The only other known supplier of amorphous metal is based in China and currently only serves the Chinese market.

3A.4.7 **Tata Steel (Cogent Power Ltd.)**

Tata Steel is the world's tenth largest steel producer, with a crude steel capacity of over 28 million tonnes. In April 2007, Tata Steel acquired Corus, an international metal company that provides electrical steel through its wholly-owned subsidiary, Cogent Power Ltd.[34] The electrical steel division of Cogent Power is comprised of Orb Works, located in South Wales, and Surahammars Bruk, headquartered in Sweden. Orb Works and Surahammars both produce a wide variety of both grain oriented and non-oriented steels. In 2009, Orb produced 90,000 tonnes of grain oriented electrical steel.[2]

3A.4.8 **ThyssenKrupp Steel**

ThyssenKrupp Steel, a subsidiary of ThyssenKrupp AG, entered the electrical steel market in 1989. In 2002 ThyssenKrupp Electrical Steel (TKES) was formed to consolidate all of the company's electrical steel activities. Further restructuring in 2004 created ThyssenKrupp Stahl AG to handle the company's non-oriented electrical steel products. TKES now deals solely with grain oriented steels. TKES is headquartered in Essen, Germany and has plants in Germany, India, Deutschland, Italy and France. ThyssenKrupp has a production capacity of approximately 1.5 million tonnes of electrical steel annually, making it the largest electrical steel producer in Europe and the third largest producer worldwide.[35] In 2009, TKES produced 250,000 tonnes of grain oriented electrical steel.[2]

3A.4.9 **China Steel Corporation (CSC)**

China Steel Corporation, the only integrated steel producer in Taiwan, was founded in 1971 and exports approximately 25 percent of its steel production volume. It currently has an annual crude steel production capacity of approximately 13.4 million tonnes and produces four grades of electrical steel.[36] China Steel Corporation does not produce grain oriented electrical steel. CSC is planning to invest $486 million in a new production line for electrical steel which would produce 150,000 to 200,000 tonnes of electrical steel annually.[37]

3A.4.10 **Pohang Iron and Steel (POSCO)**

POSCO, located in the port city of Pohang, South Korea, was founded in 1958, produced 35 million tonnes of steel in 2010, and has approximately 30,000 employees.[38] In 2009, POSCO had about one million tonnes of electrical steel capacity annually. POSCO is considering partnering with Steel Authority of India Limited (SAIL) to build a production complex with a proposed annual capacity of about 3 million tonnes.[39] In 2009, POSCO produced 250,000 tonnes of grain oriented electrical steel.[2]

3A.4.11 **Shanghai Baosteel Group Corporation**

Shanghai Baosteel, formerly Baoshan Iron & Steel, is state owned and China's largest iron and steel maker. Baosteel and its 22 wholly-owned subsidiaries have an annual production capacity of around 30 million metric tons of crude steel and 600,000 tonnes of electrical steel. In 2009, it produced 90,000 tonnes of grain oriented electrical steel.[2]

3A.4.12 **Wuhan Iron and Steel Company**

Wuhan (WISCO), a Chinese company, produced 30 million metric tons of crude steel in 2009, and increased its annual electrical steel capacity to 2 million metric tons in 2010 with the completion of three new production lines. Currently, more than half of domestic silicon steel demand in China is met by WISCO.[40] In 2009, WISCO produced 440,000 tonnes of grain oriented electrical steel, making it the largest producer of grain oriented steel.[2]

3A.4.13 **ArcelorMittal**

ArcelorMittal, a Brazilian company, was founded in 1944 and produced a total of 90.6 million tonnes of crude steel in 2010, representing approximately 8 percent of world steel output.[41] ArcelorMittal offers both grain oriented and non-oriented electrical steel. In 2010, ArcelorMittal proposed a 50-50 joint venture with SAIL to set up a steel facility in Bokaro, India.[39] Additionally, in 2008 ArcelorMittal entered into a joint venture with Hunan Valin Steel Group to build a steel facility in China with a projected annual capacity of 200,000 tonnes of grain oriented steel. In 2009, ArcelorMittal produced 107,000 tonnes of grain oriented electrical steel.[2]

3A.4.14 **Stalprodukt S.A.**

In 1992, the Polish company Stalprodukt S.A. purchased two former Sendzimir Steel Works production plants. Stalprodukt S.A. produces four grades of grain oriented electrical steels. In 2009, Stalprodukt S.A. produced 62,000 tonnes of grain oriented electrical steel.[2]

3A.4.15 **Angang Steel**

Angang Steel, located in China, was incorporated in 1997 with Anshan Iron and Steel Group Complex as its sole promoter. It produces a wide array of steel products, and began the mass production of grain oriented steel at the beginning of 2011. The facilities are expected to have the capacity to produce 100,000 tonnes of grain oriented electrical steel annually.[42]

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APPENDIX 5A. ADDITIONAL ENGINEERING ANALYSIS RESULTS

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APPENDIX 5A. ADDITIONAL ENGINEERING ANALYSIS RESULTS

5A.1 INTRODUCTION

This appendix provides additional results from the engineering analysis, including information about the distributions by price for each of the representative units analyzed. These results are based on the reference case engineering analysis and the 2011 price scenario. These results include the following:

1. No-load (core) losses versus manufacturer's selling price
2. Load-losses (coil) versus manufacturer's selling price
3. Transformer weight versus efficiency

Table 5A.1 is reproduced from chapter 5 for reference, and provides a summary of the engineering design lines and the specifications of each of the representative units.

Table 5A.1 Engineering Design Lines (DLs) and Representative Units for Analysis

EC*	DL	Type of Distribution Transformer	kVA Range	Representative Unit for this Engineering Design Line
1	1	Liquid-immersed, single-phase, rectangular tank	10–167	50 kVA, 65°C, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank, 95kV BIL
	2	Liquid-immersed, single-phase, round tank	10–167	25 kVA, 65°C, single-phase, 60Hz, 14400V primary, 120/240V secondary, round tank, 125 kV BIL
	3	Liquid-immersed, single-phase	250–833	500 kVA, 65°C, single-phase, 60Hz, 14400V primary, 277V secondary, 150kV BIL
2	4	Liquid-immersed, three-phase	15–500	150 kVA, 65°C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary, 95kV BIL
	5	Liquid-immersed, three-phase	750–2500	1500 kVA, 65°C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary, 125 kV BIL
3	6	Dry-type, low-voltage, single-phase	15–333	25 kVA, 150°C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL
4	7	Dry-type, low-voltage, three-phase	15–150	75 kVA, 150°C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL
	8	Dry-type, low-voltage, three-phase	225–1000	300 kVA, 150°C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL
6	9	Dry-type, medium-voltage, three-phase, 20-45kV BIL	15–500	300 kVA, 150°C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL
	10	Dry-type, medium-voltage, three-phase, 20-45kV BIL	750–2500	1500 kVA, 150°C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
8	11	Dry-type, medium-voltage, three-phase, 46-95kV BIL	15–500	300 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
	12	Dry-type, medium-voltage, three-phase, 46-95kV BIL	750–2500	1500 kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
10	13A	Dry-type, medium-voltage, three-phase, 96-150kV BIL	75–833	300 kVA, 150°C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL
	13B	Dry-type, medium-voltage, three-phase, 96-150kV BIL	225–2500	2000 kVA, 150°C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL

* EC means equipment class (see Chapter 3 of the TSD). DOE did not select any representative units from the single-phase, medium-voltage equipment classes (EC5, EC7 and EC9), but calculated the analytical results for EC5, EC7, and EC9 based on the results for their three-phase counterparts.

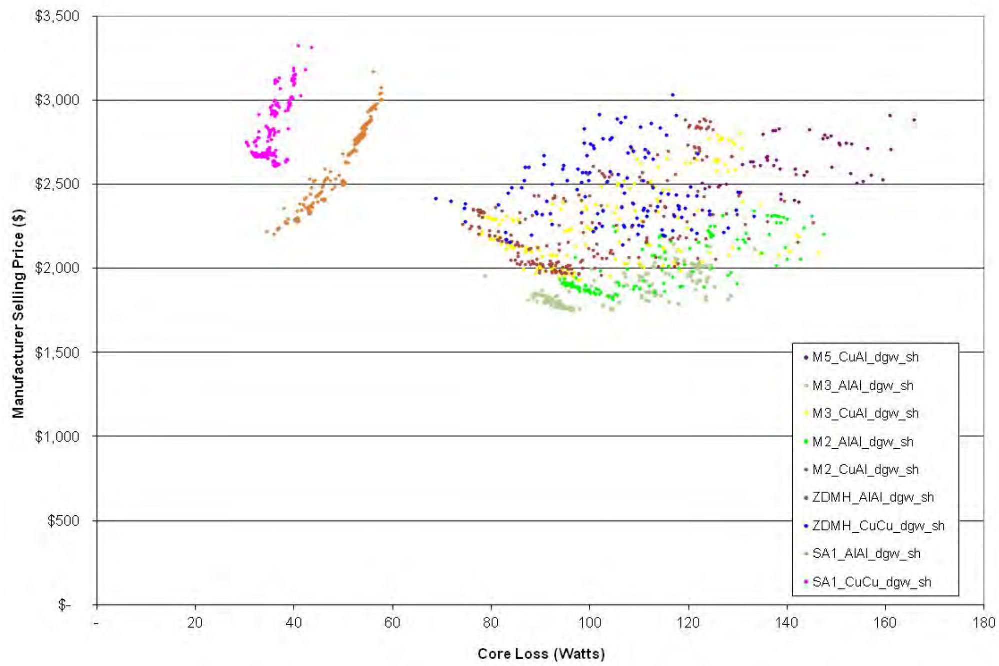


Figure 5A.5.1 Plot of Manufacturer Selling Price and Core Losses for Design Line 1

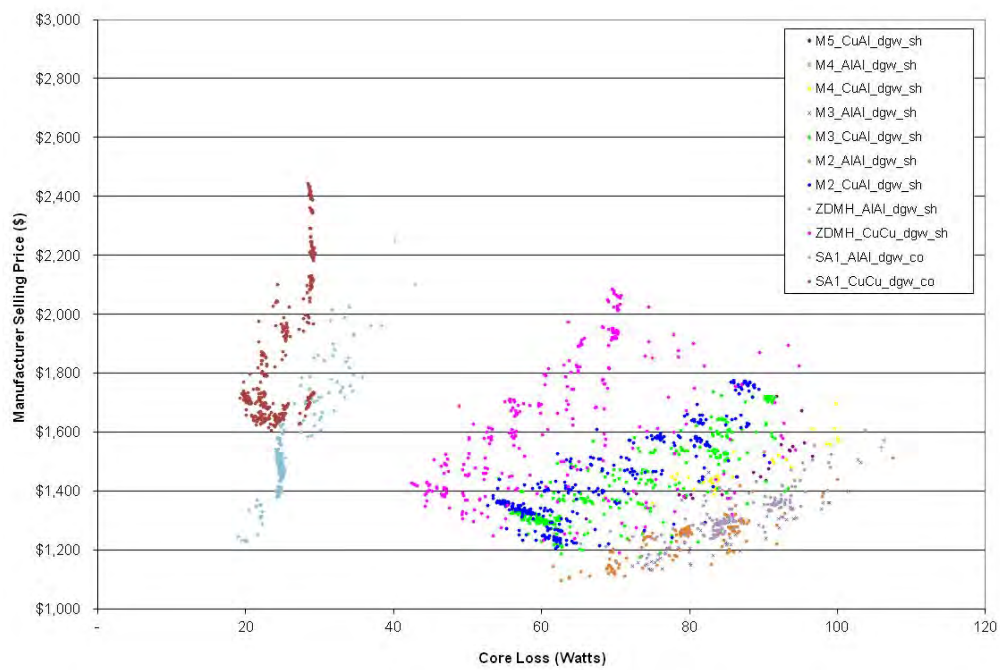


Figure 5A.5.2 Plot of Manufacturer Selling Price and Core Losses for Design Line 2

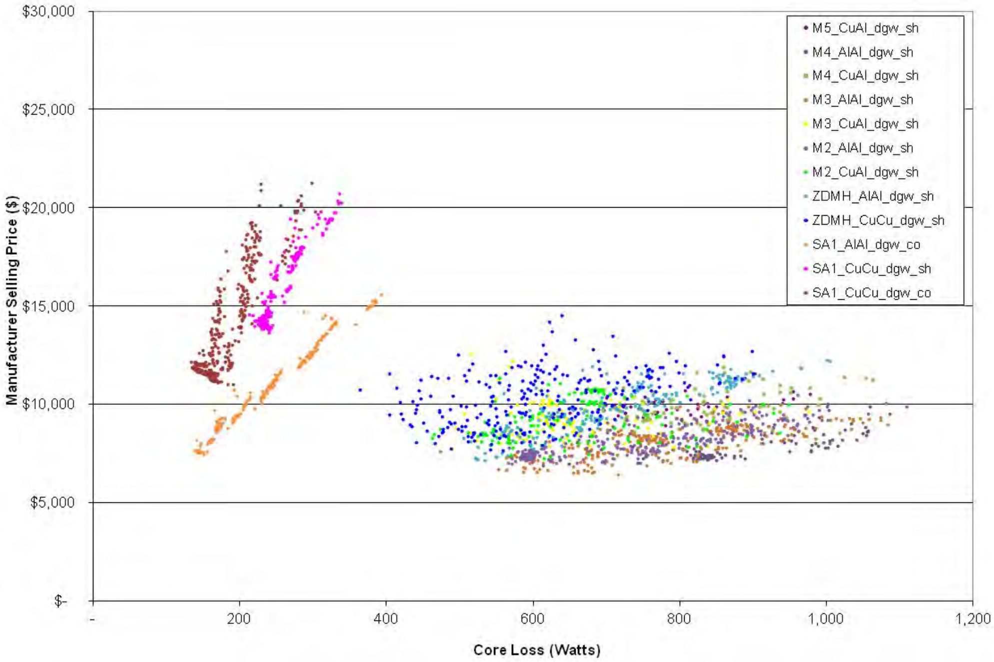


Figure 5A.5.3 Plot of Manufacturer Selling Price and Core Losses for Design Line 3

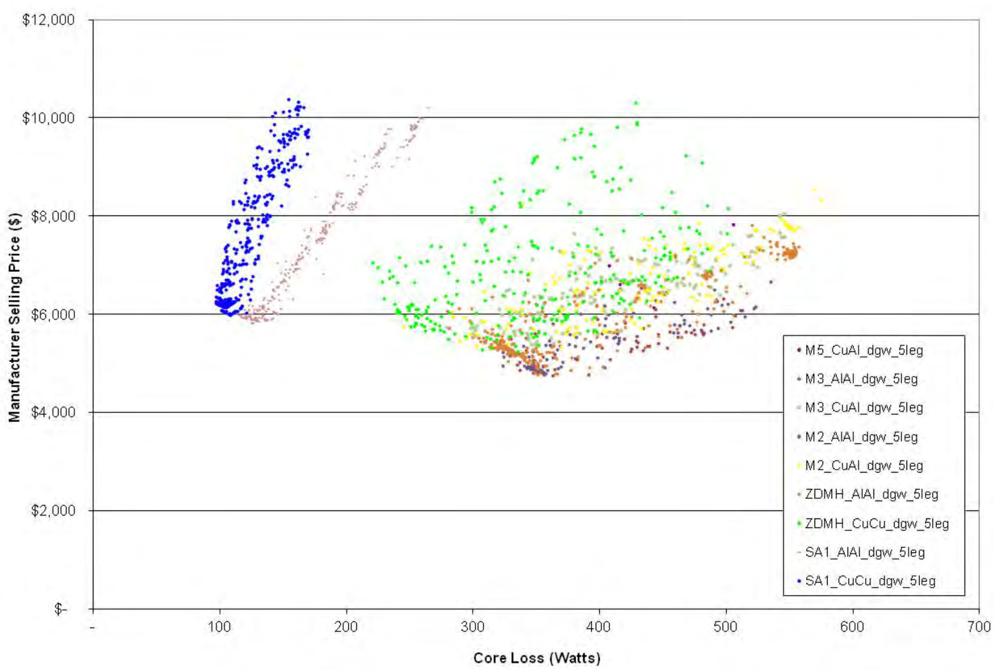


Figure 5A.5.4 Plot of Manufacturer Selling Price and Core Losses for Design Line 4

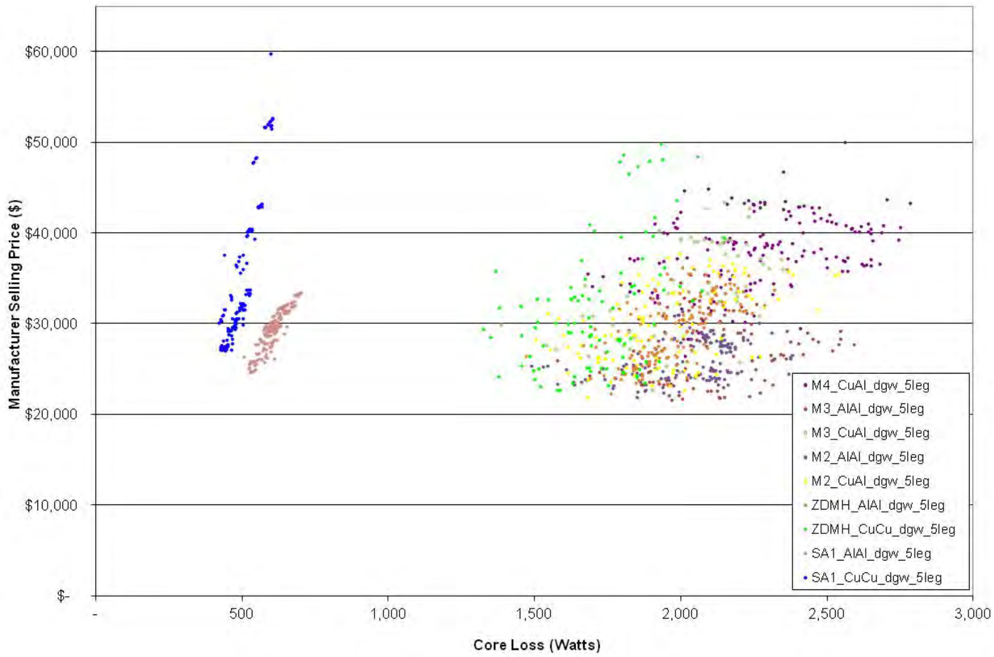


Figure 5A.5.5 Plot of Manufacturer Selling Price and Core Losses for Design Line 5

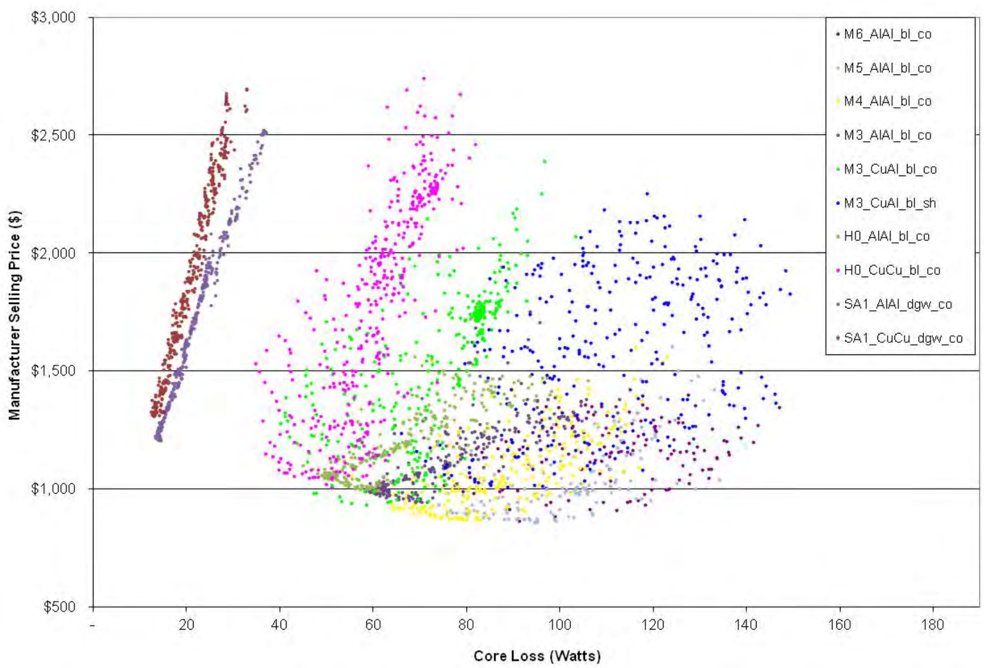


Figure 5A.5.6 Plot of Manufacturer Selling Price and Core Losses for Design Line 6

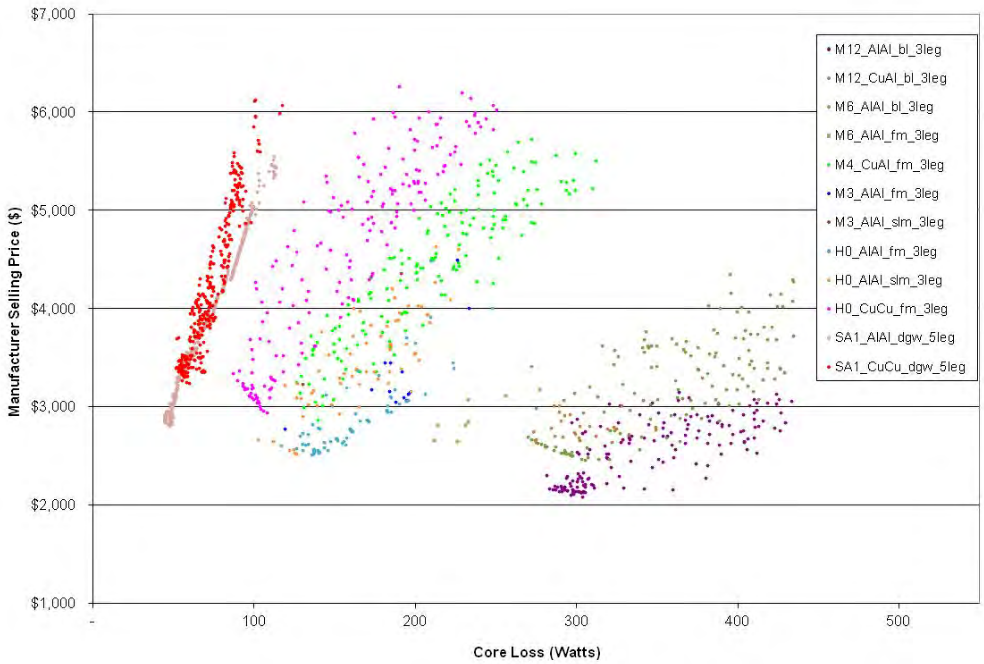


Figure 5A.5.7 Plot of Manufacturer Selling Price and Core Losses for Design Line 7

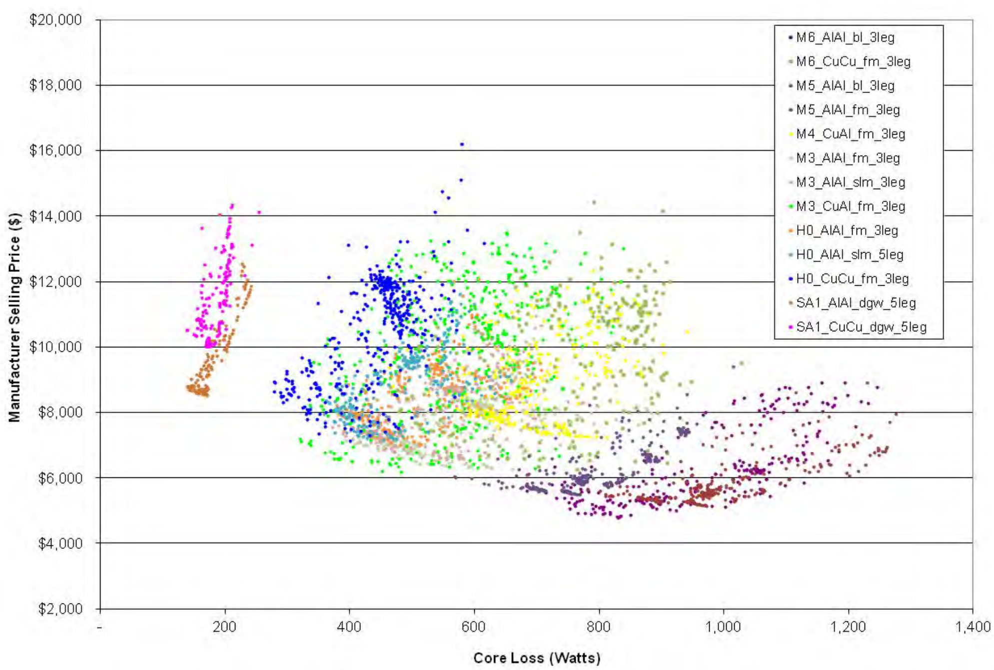


Figure 5A.5.8 Plot of Manufacturer Selling Price and Core Losses for Design Line 8

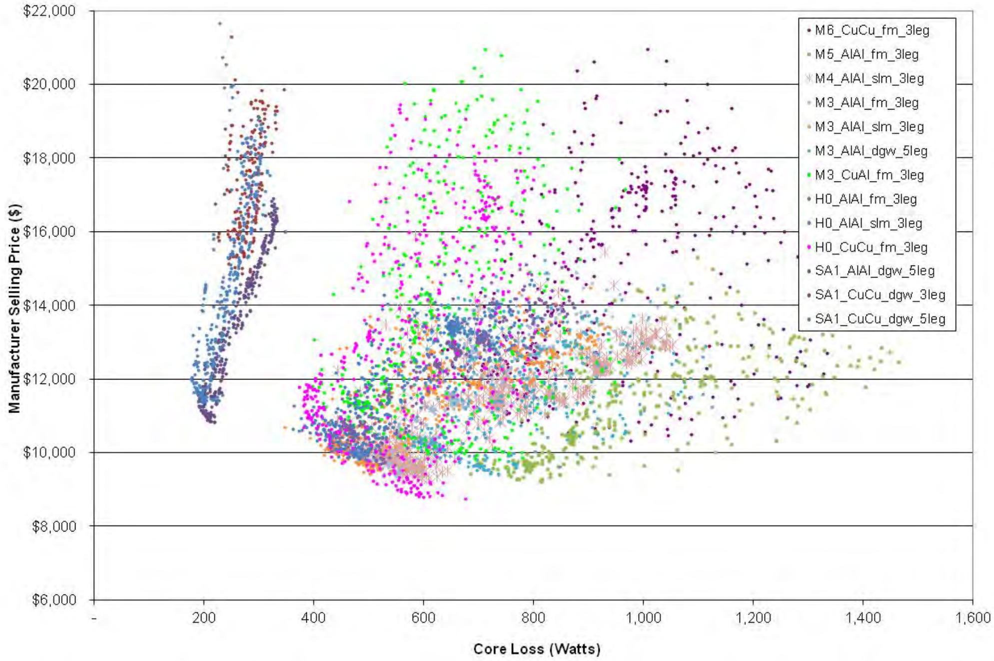


Figure 5A.5.9 Plot of Manufacturer Selling Price and Core Losses for Design Line 9

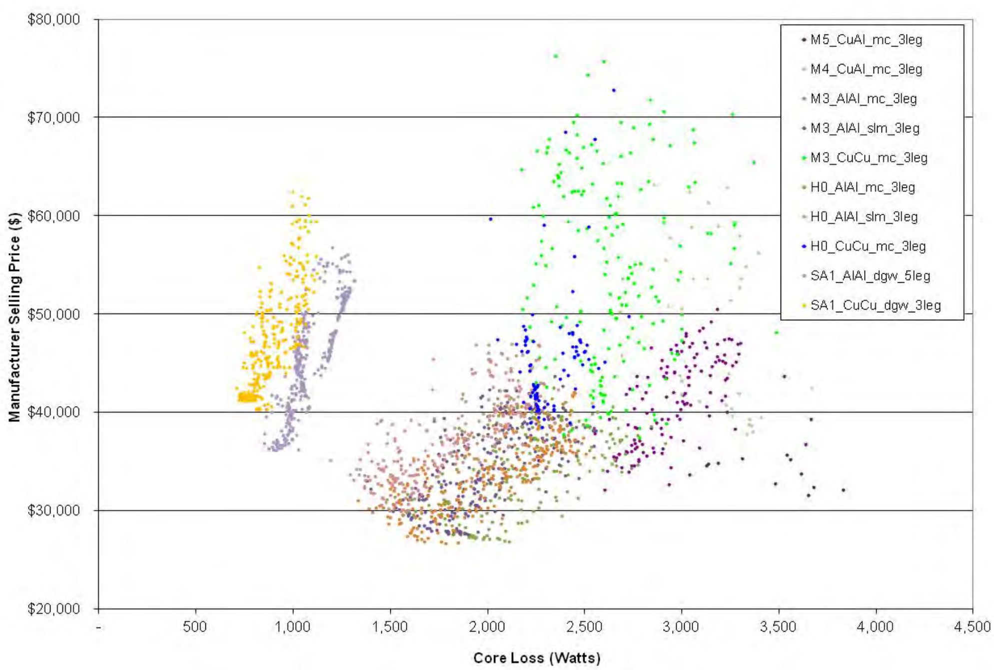


Figure 5A.5.10 Plot of Manufacturer Selling Price and Core Losses for Design Line 10

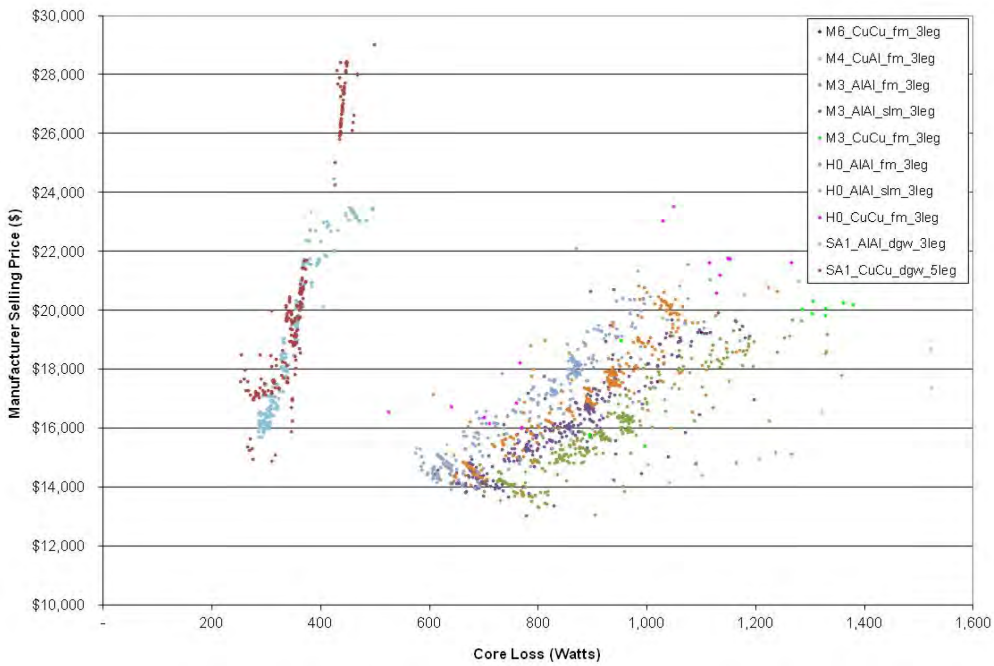


Figure 5A.5.11 Plot of Manufacturer Selling Price and Core Losses for Design Line 11

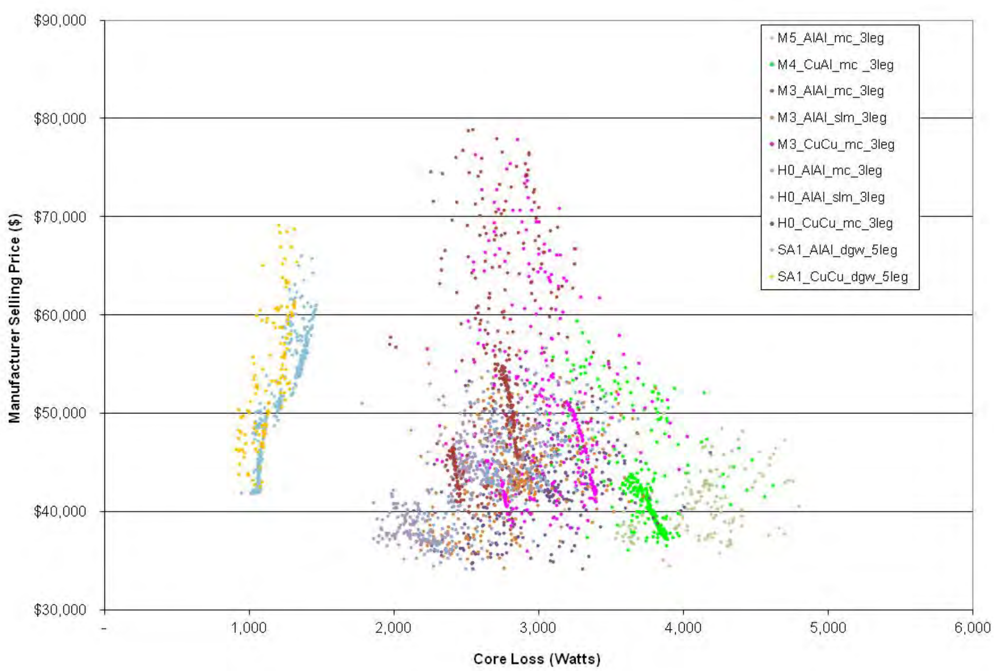


Figure 5A.5.12 Plot of Manufacturer Selling Price and Core Losses for Design Line 12

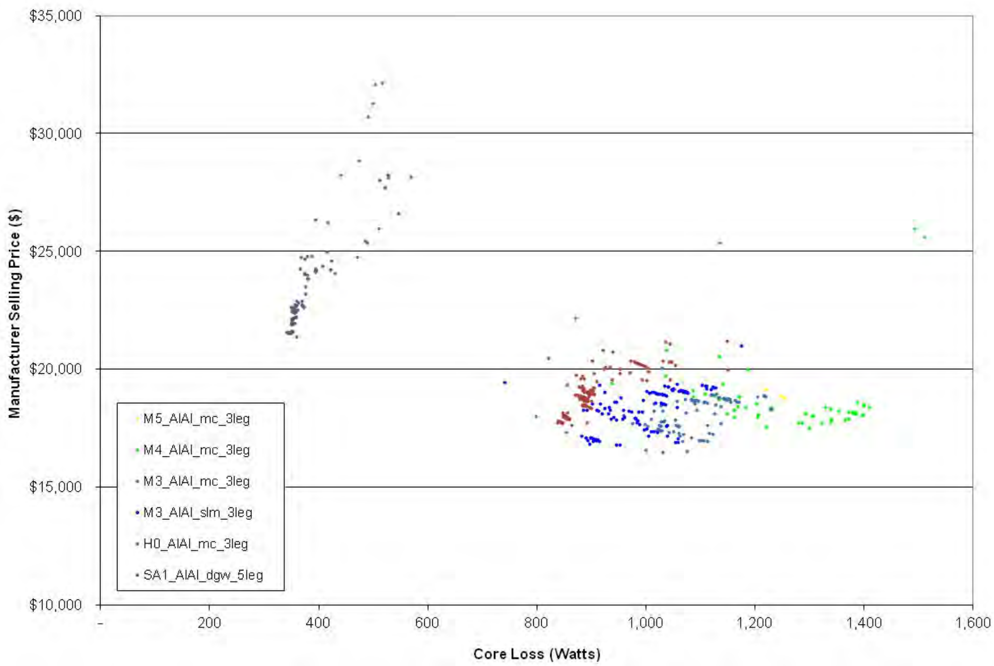


Figure 5A.5.13 Plot of Manufacturer Selling Price and Core Losses for Design Line 13A

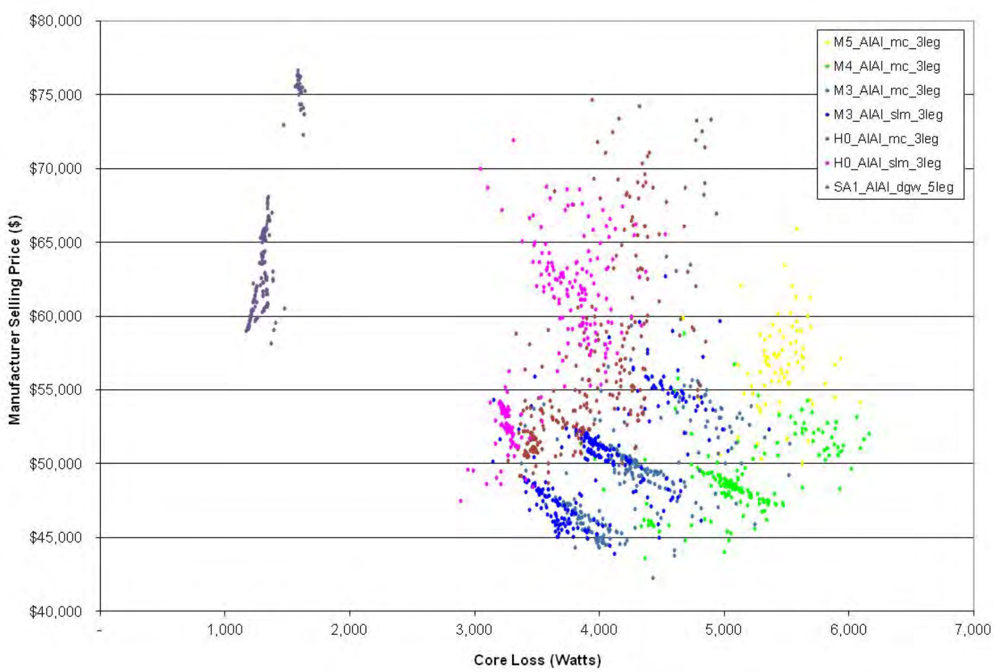


Figure 5A.5.14 Plot of Manufacturer Selling Price and Core Losses for Design Line 13B

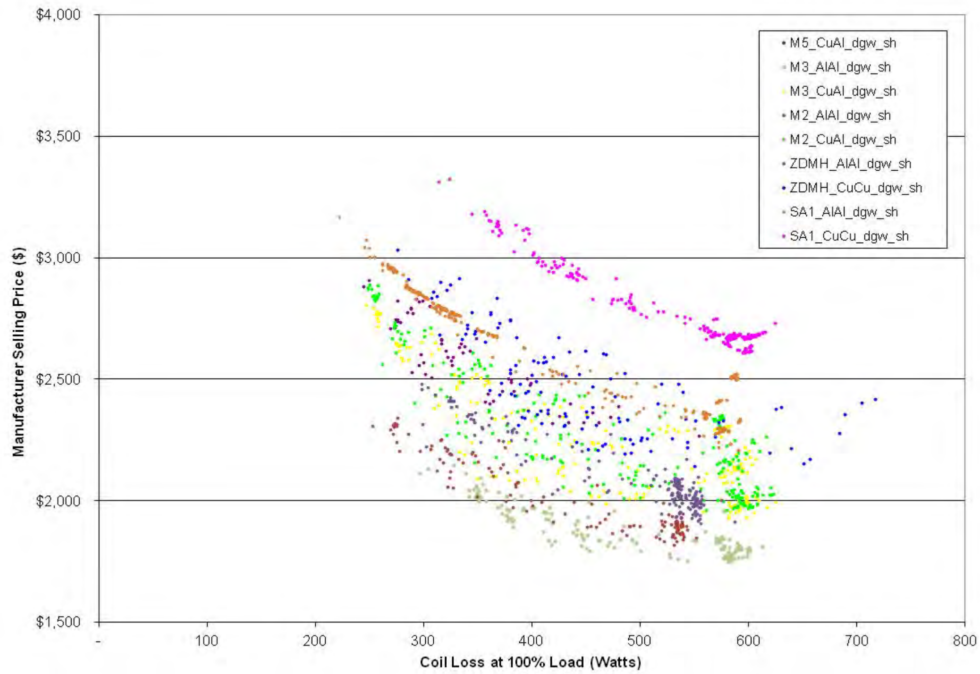


Figure 5A.5.15 Plot of Manufacturer Selling Price and Coil Losses for Design Line 1

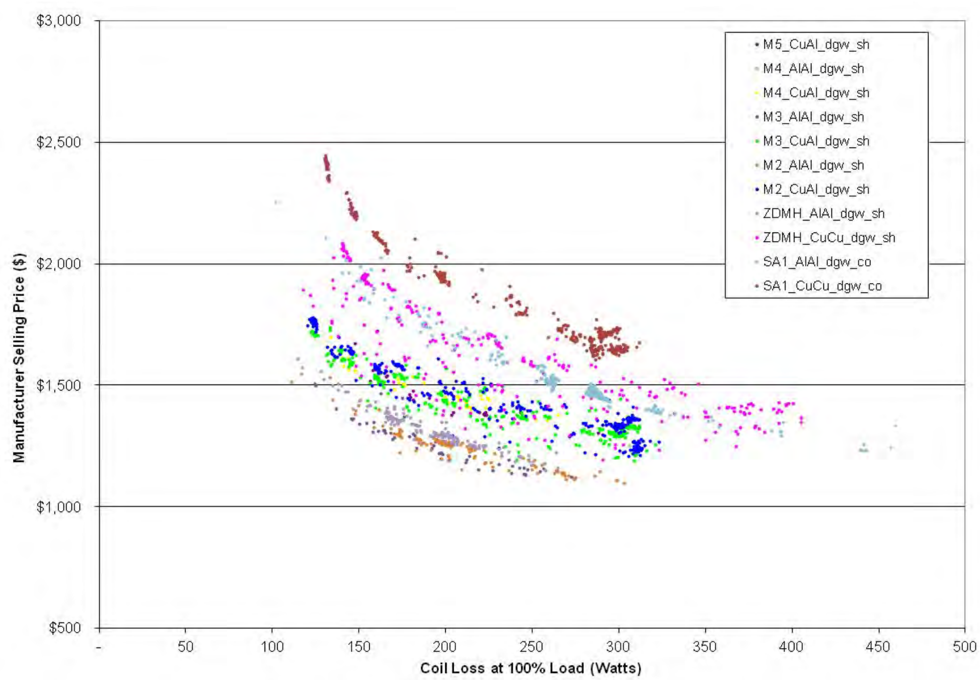


Figure 5A.5.16 Plot of Manufacturer Selling Price and Coil Losses for Design Line 2

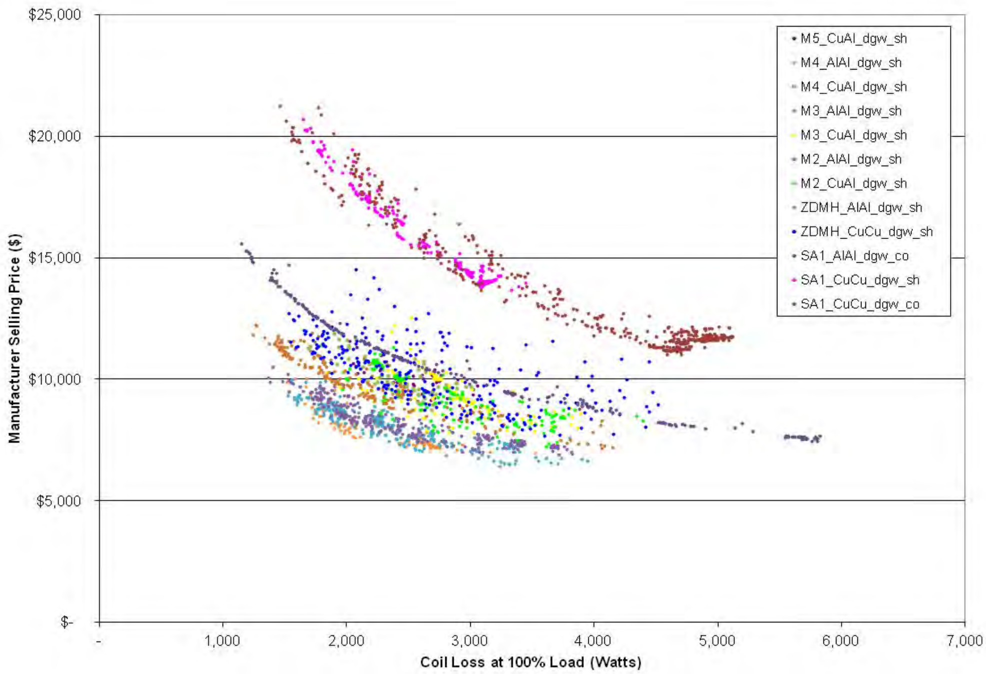
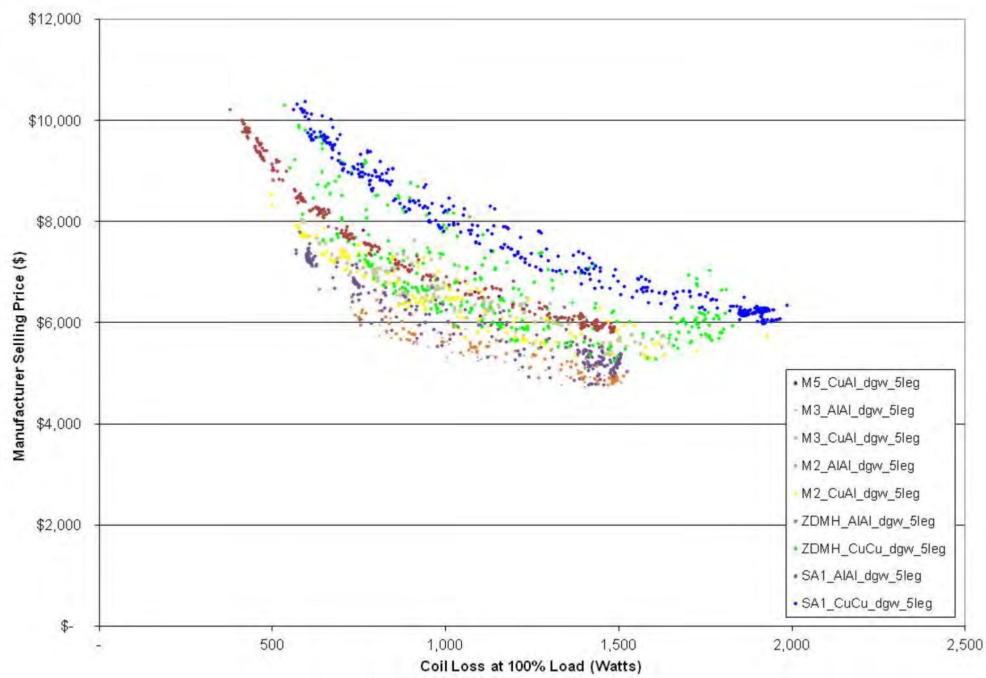


Figure 5A.5.17 Plot of Manufacturer Selling Price and Coil Losses for Design Line 3



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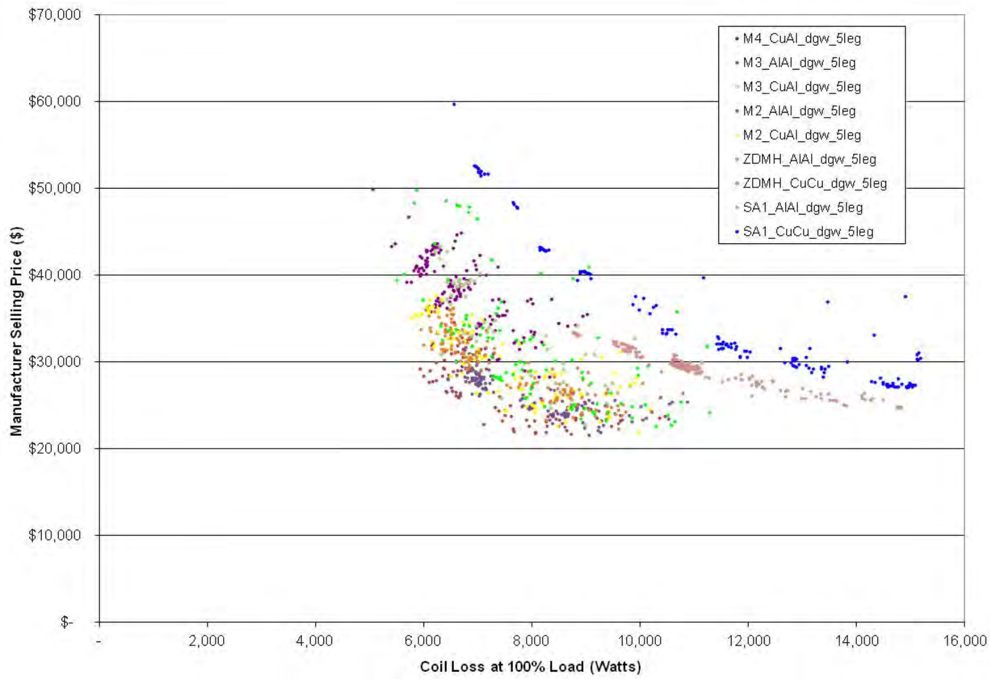

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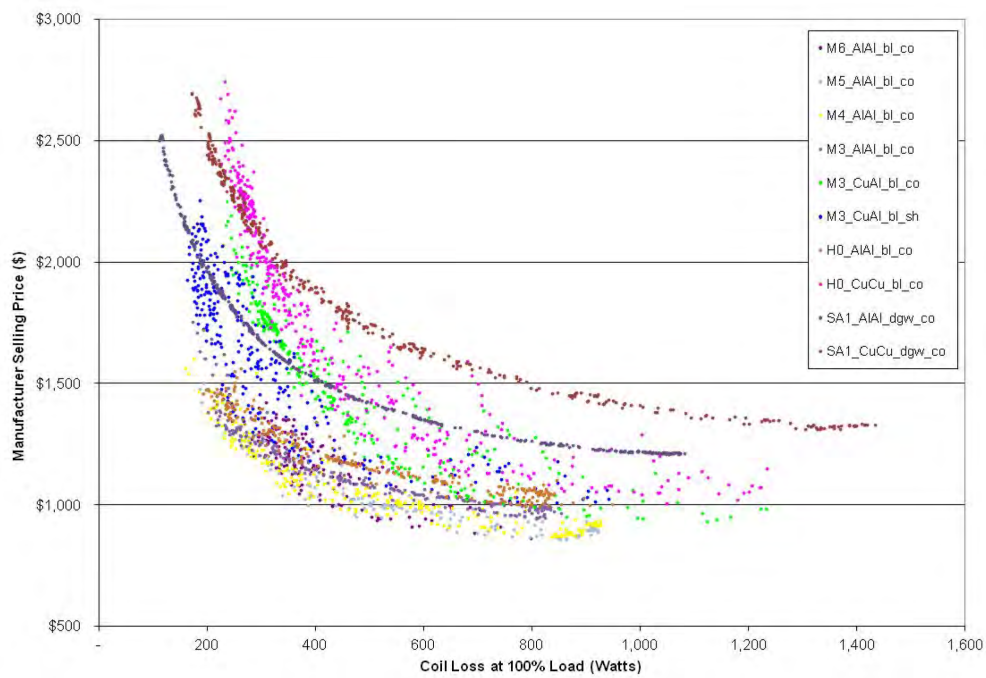

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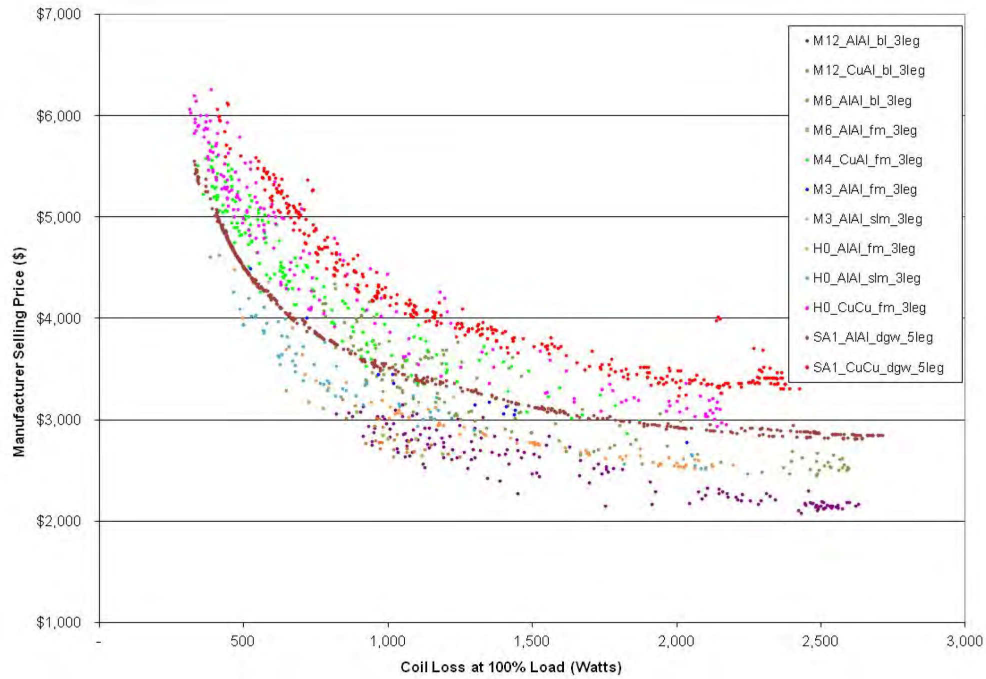

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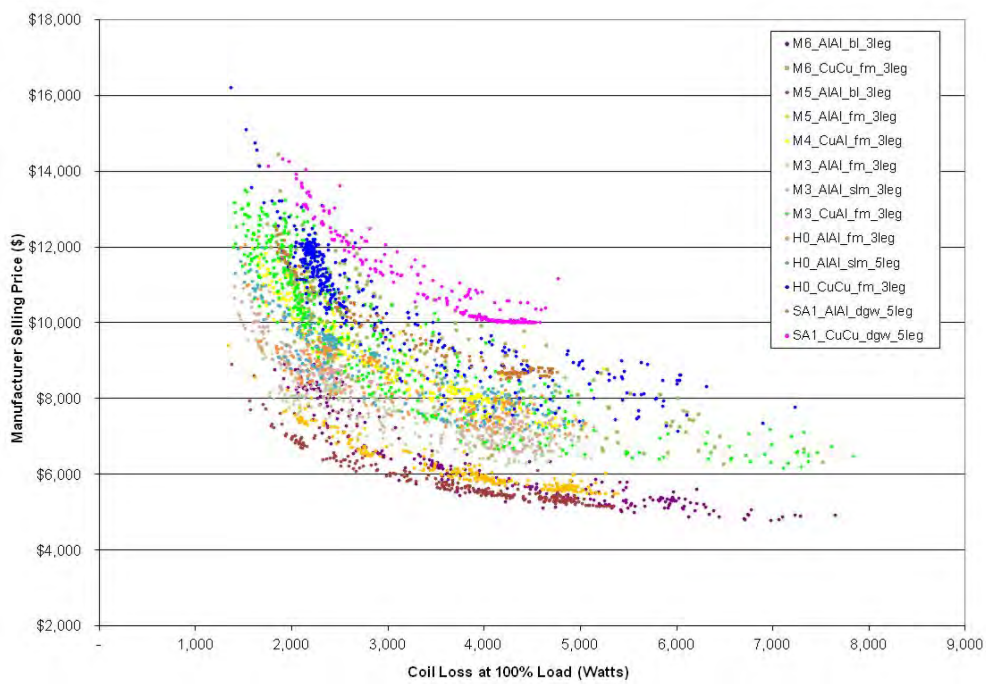

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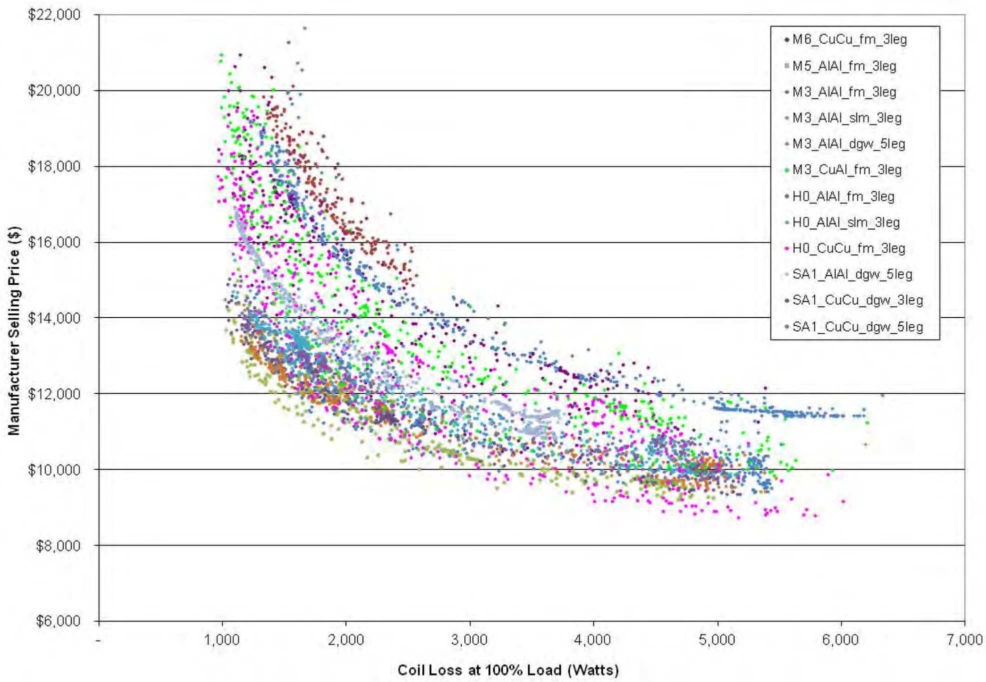

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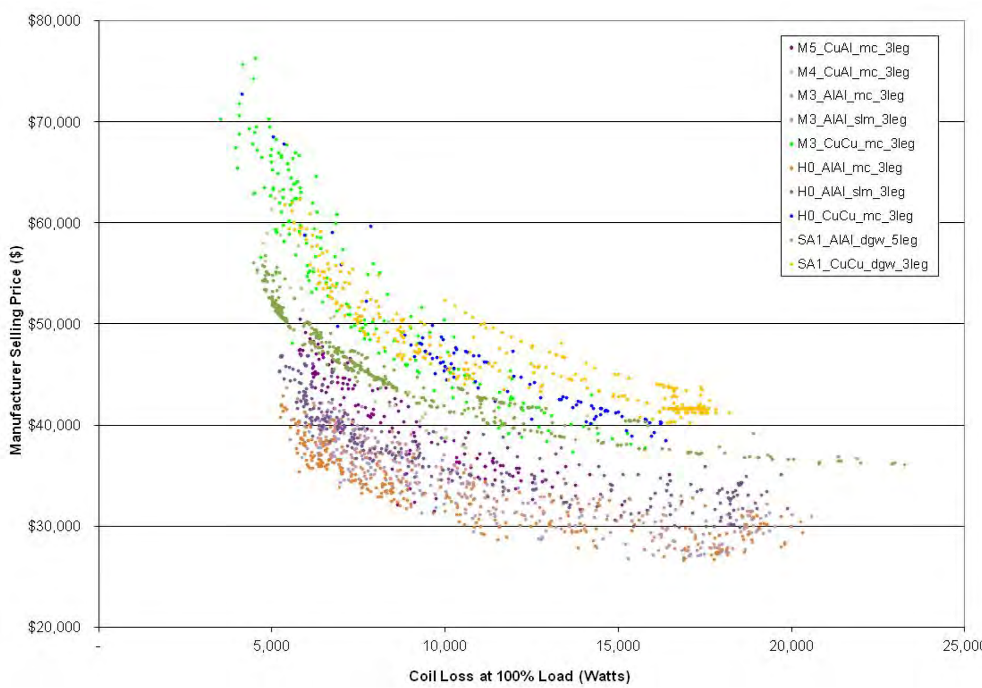

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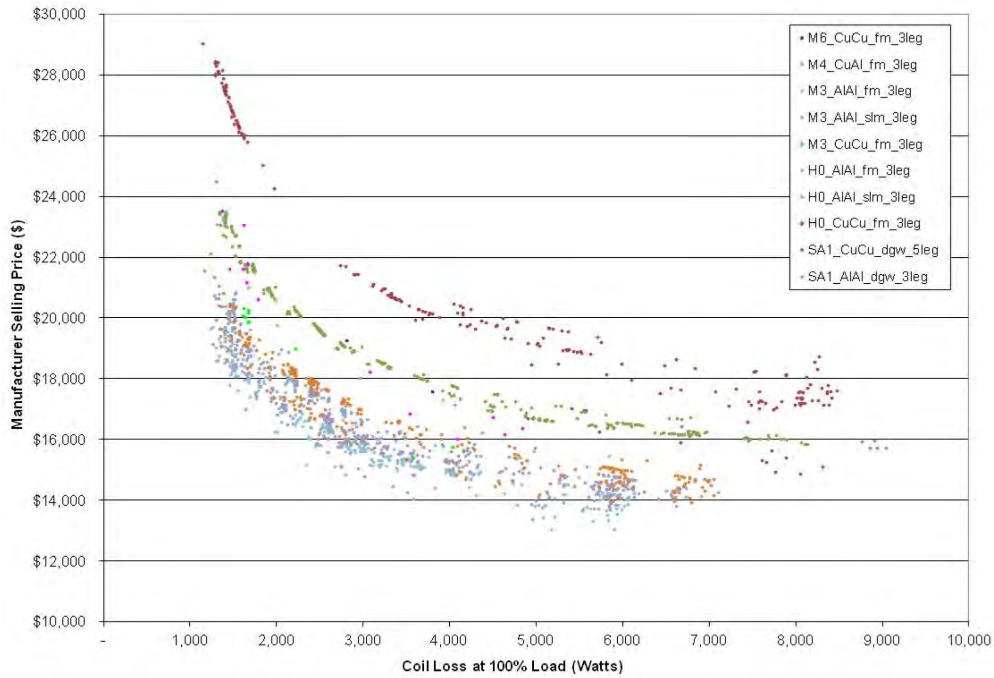

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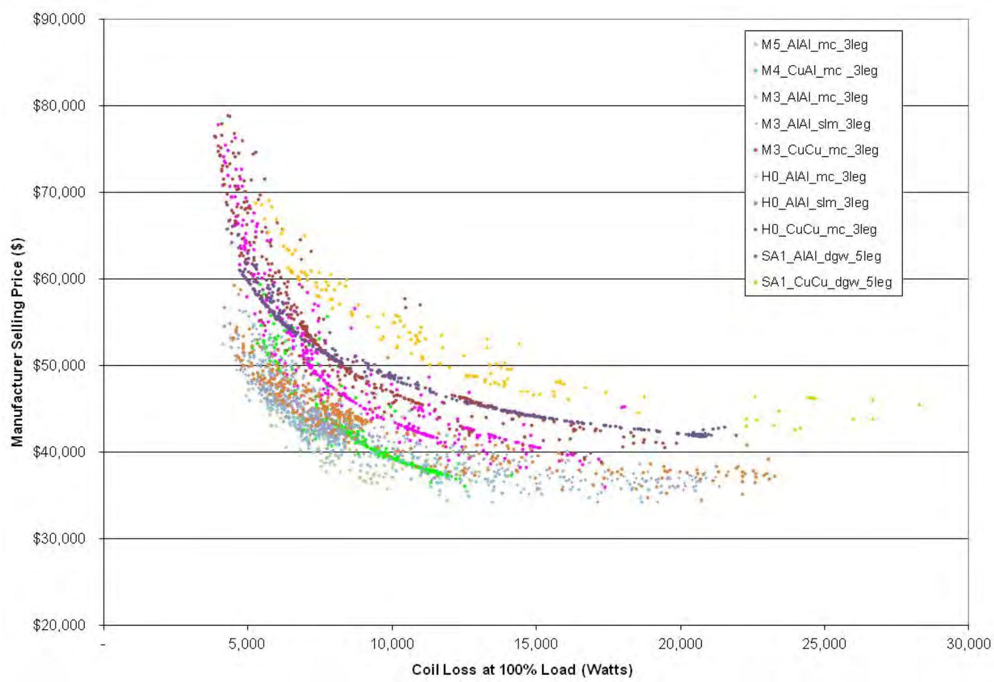

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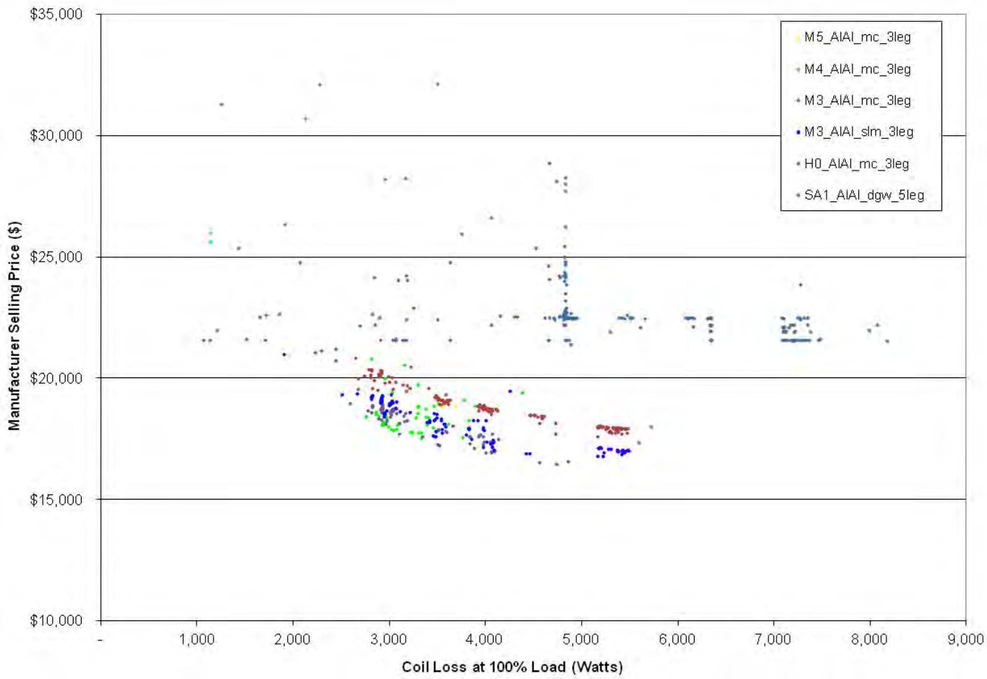

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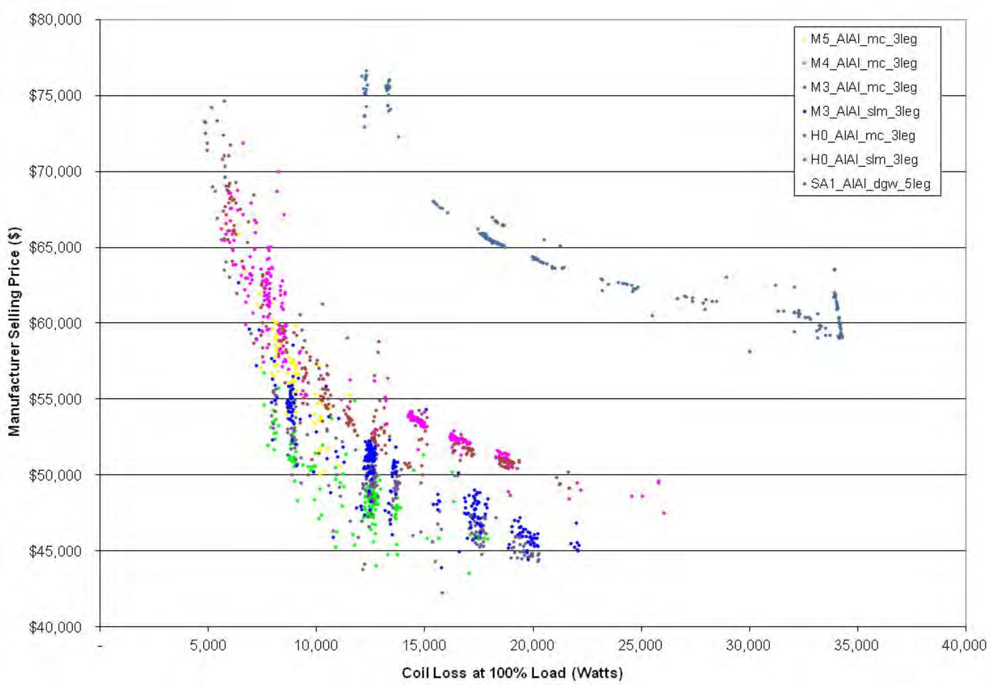

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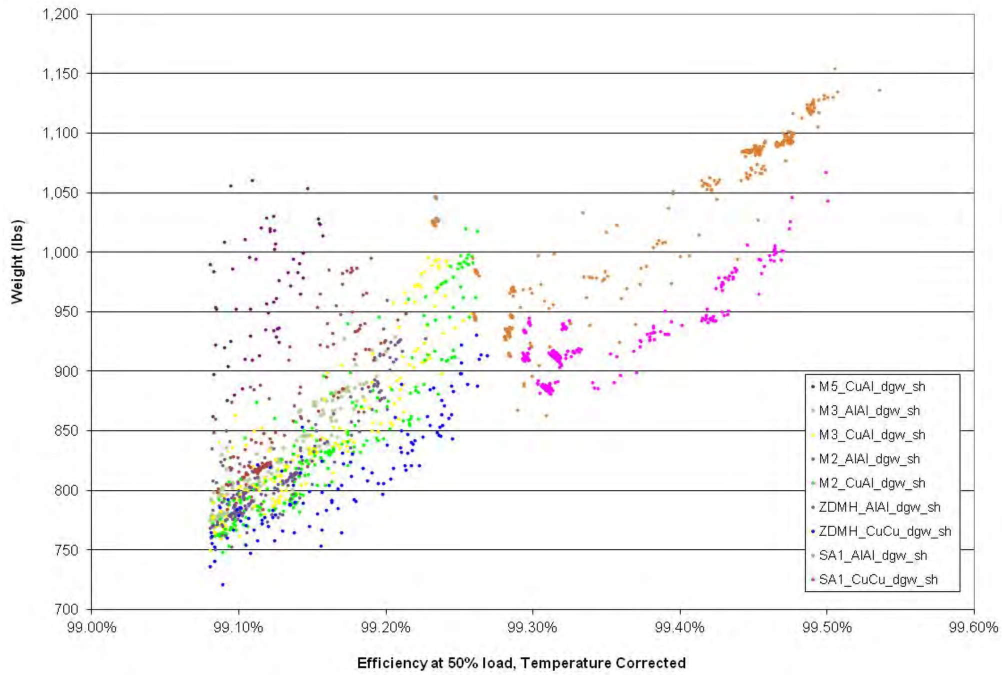

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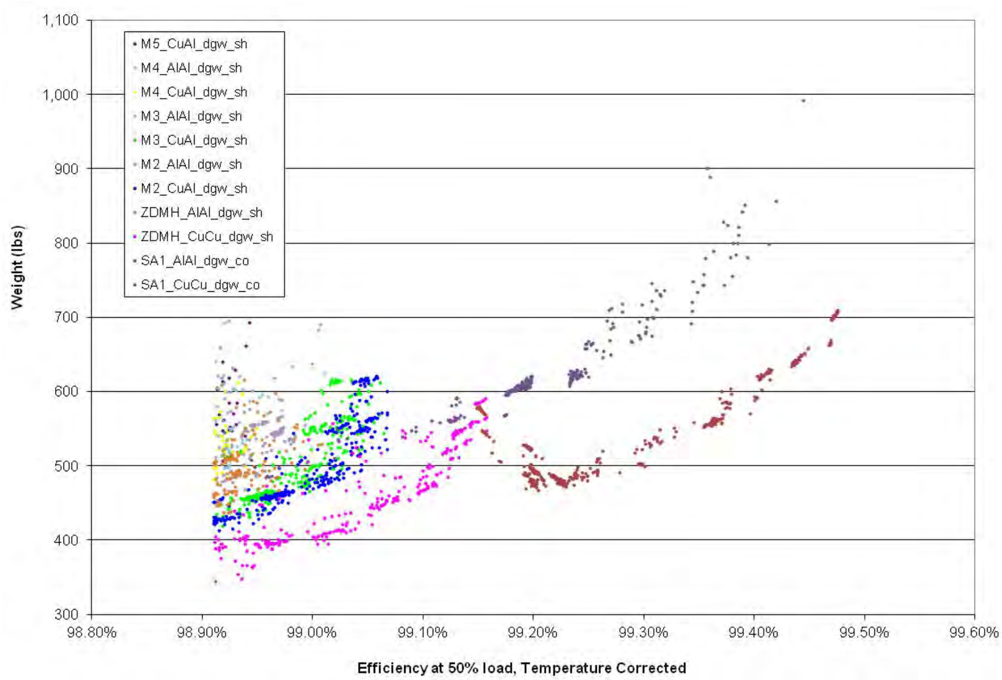

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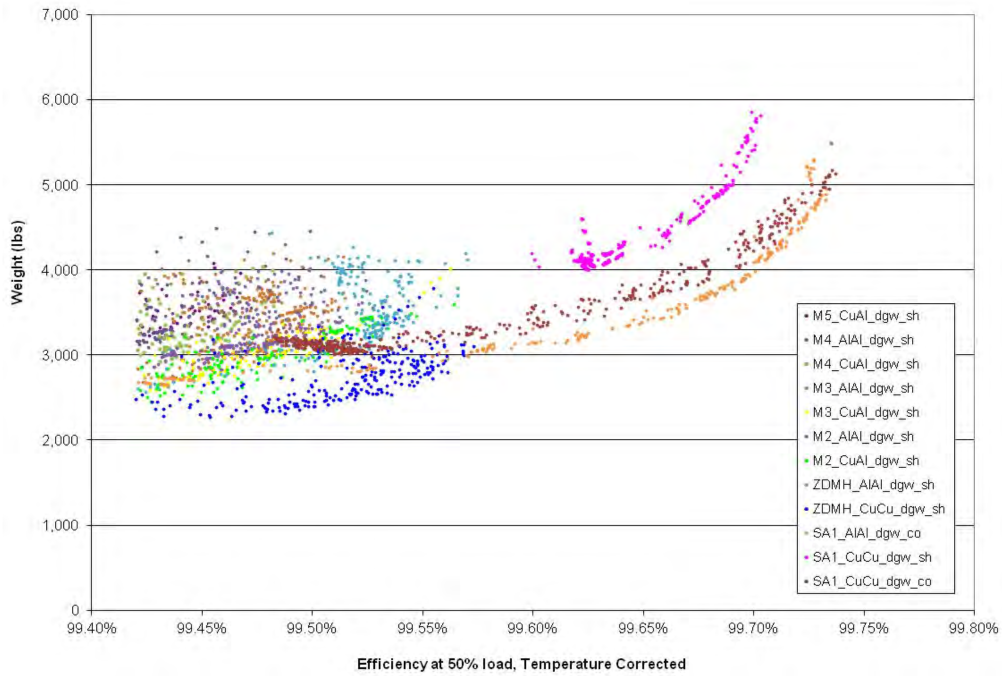

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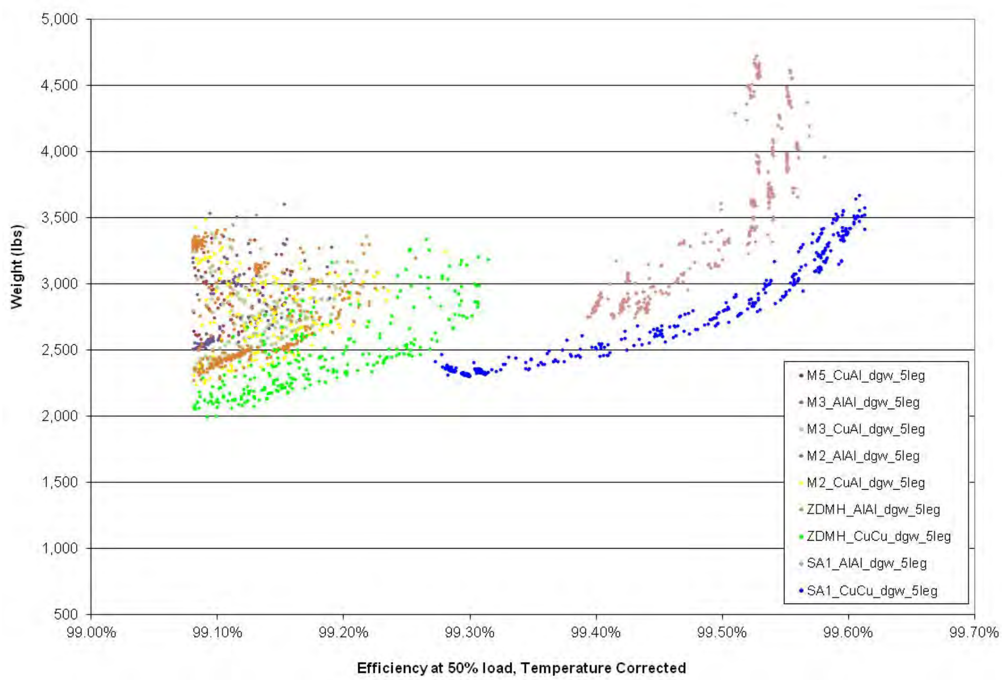

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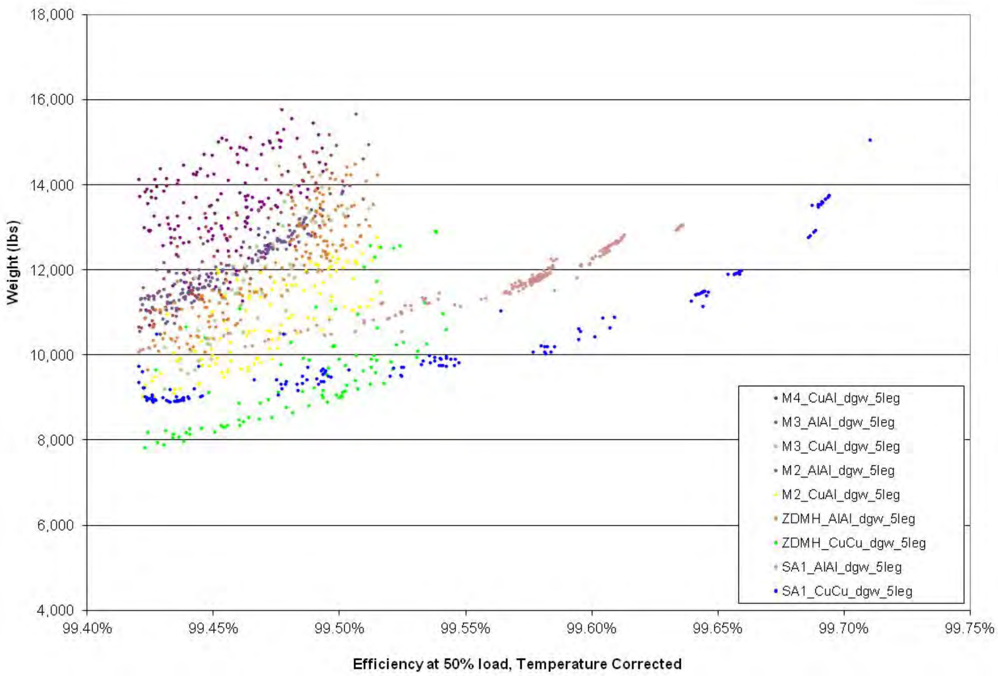

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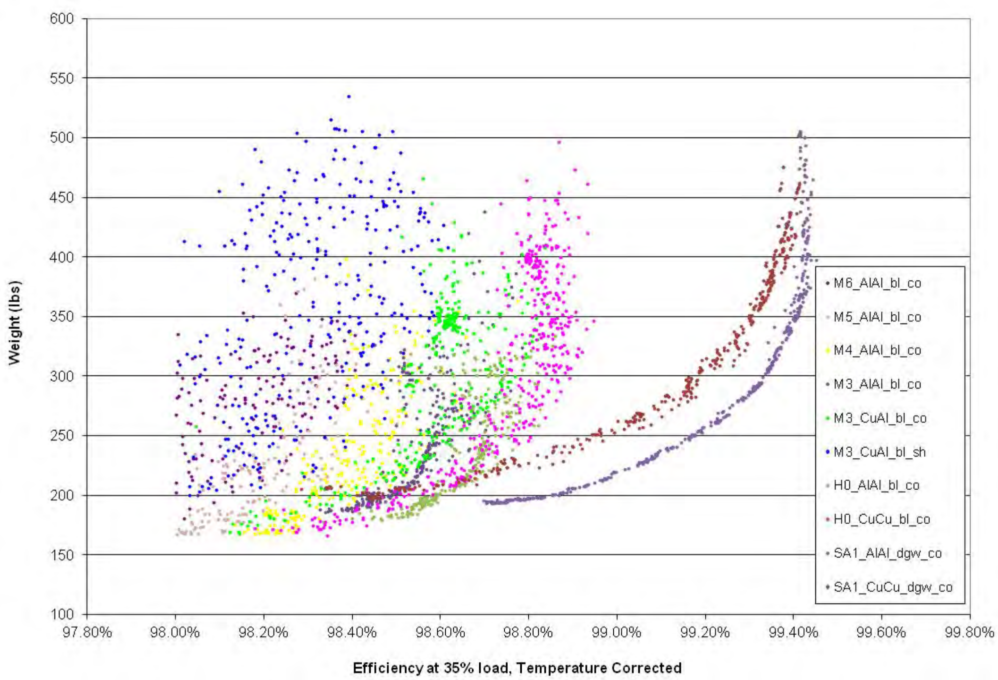

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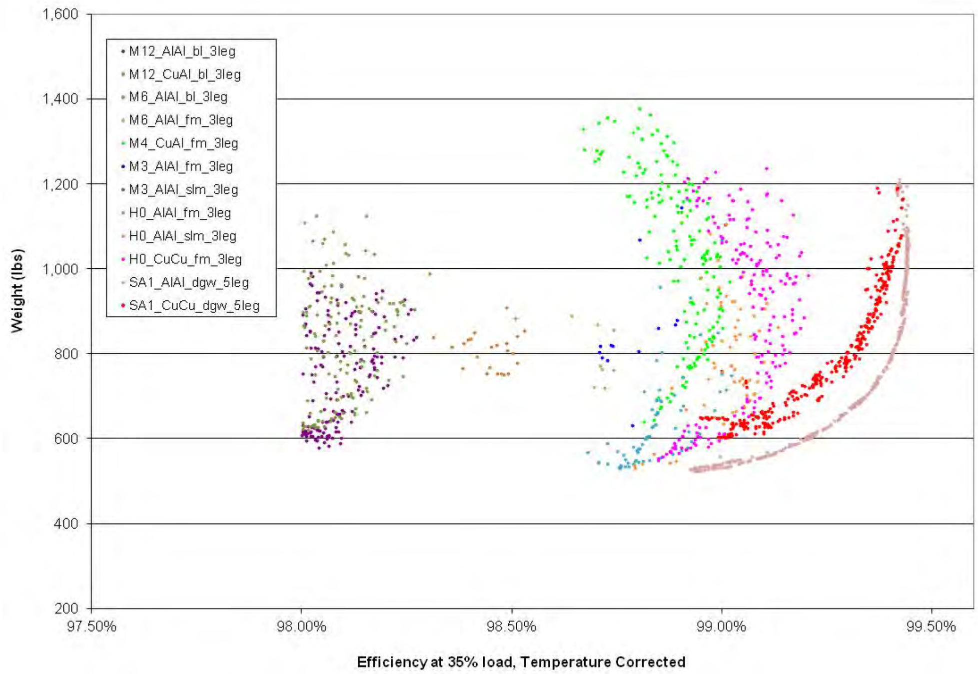

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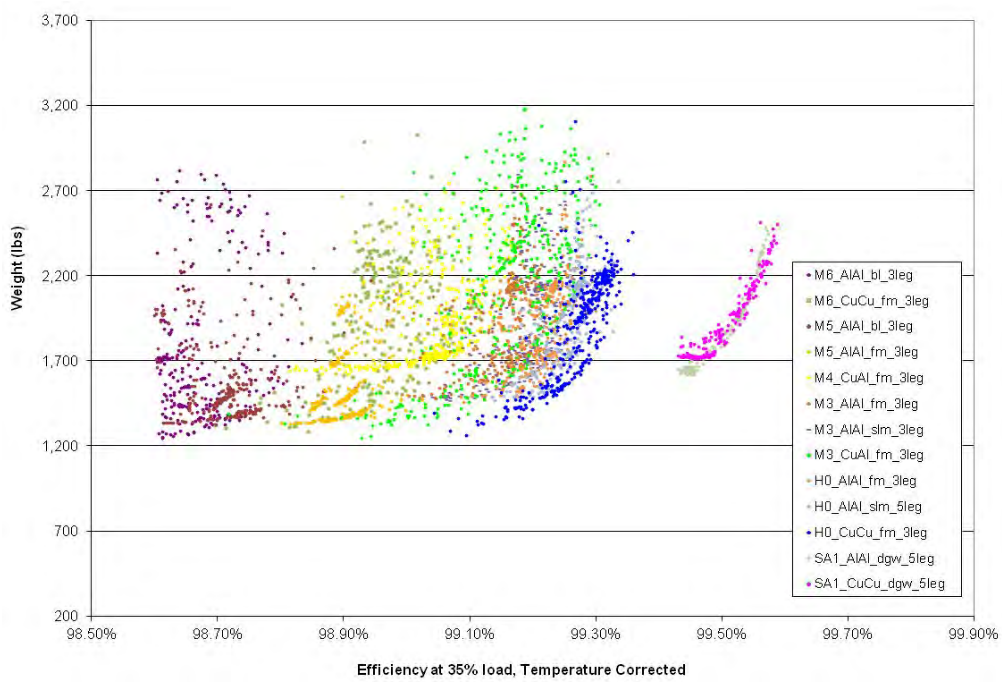

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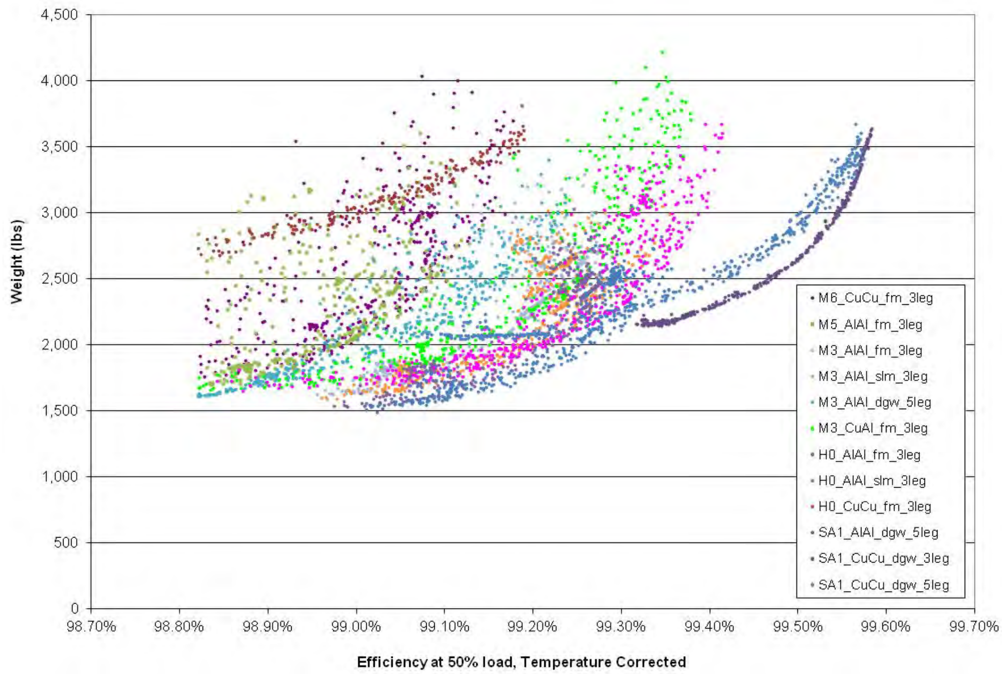

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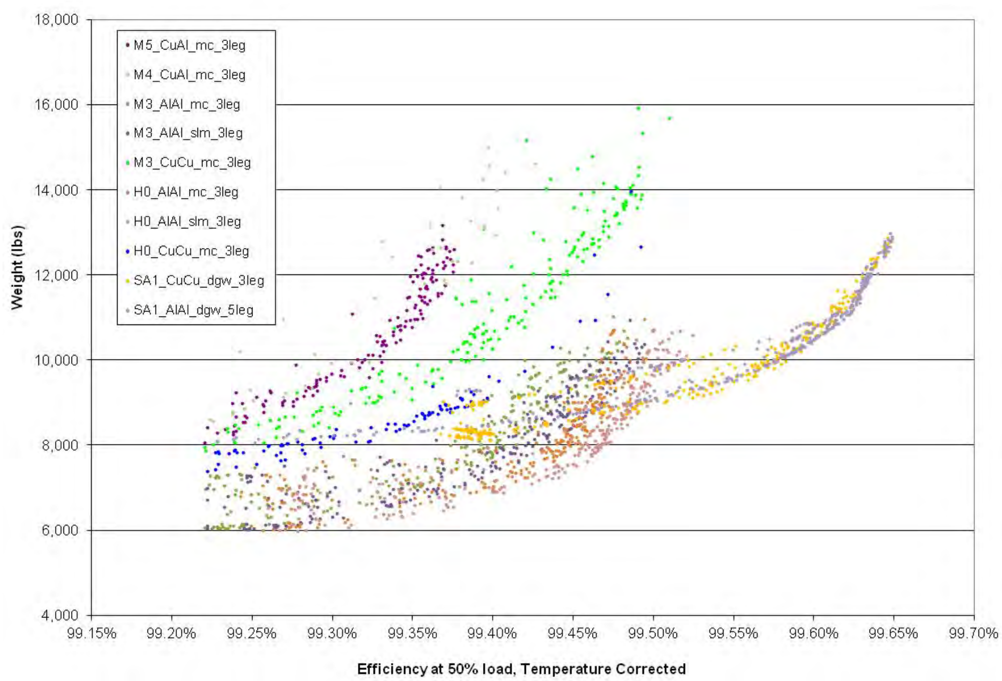

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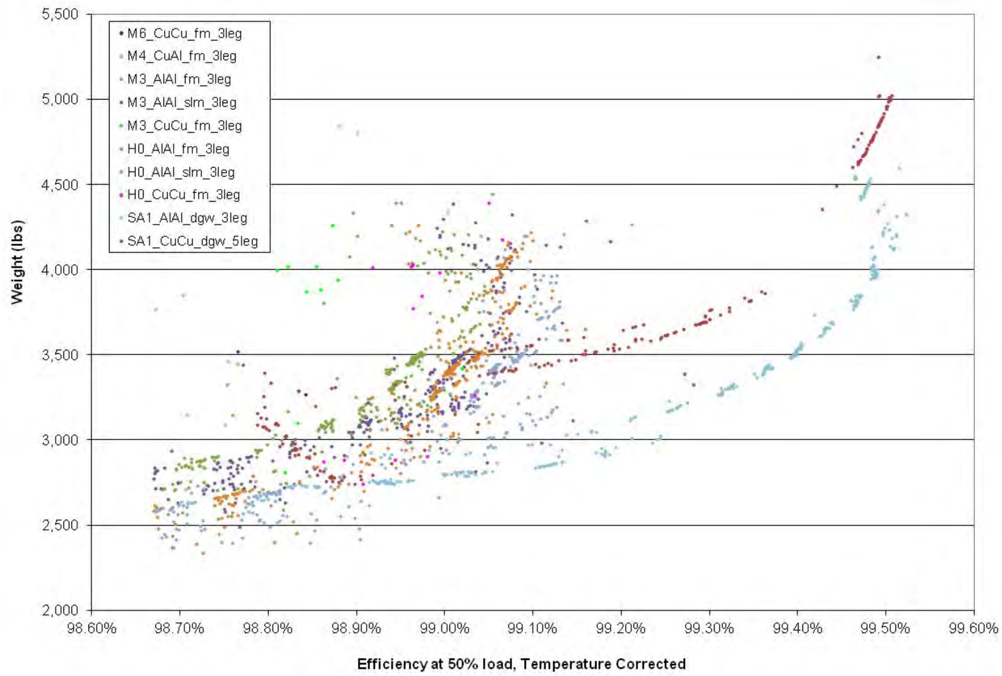

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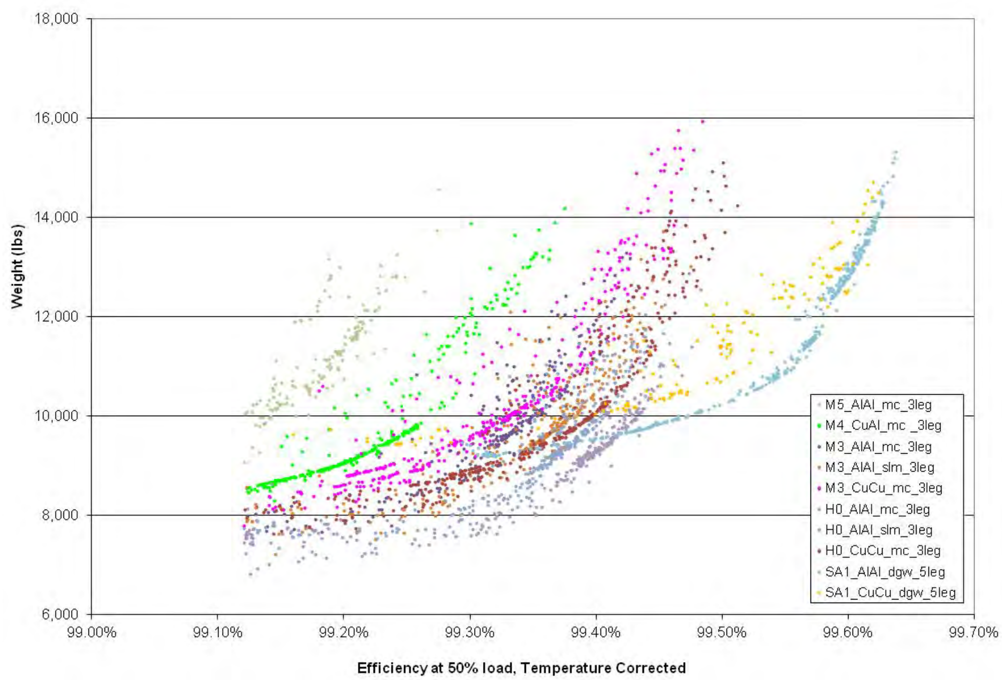

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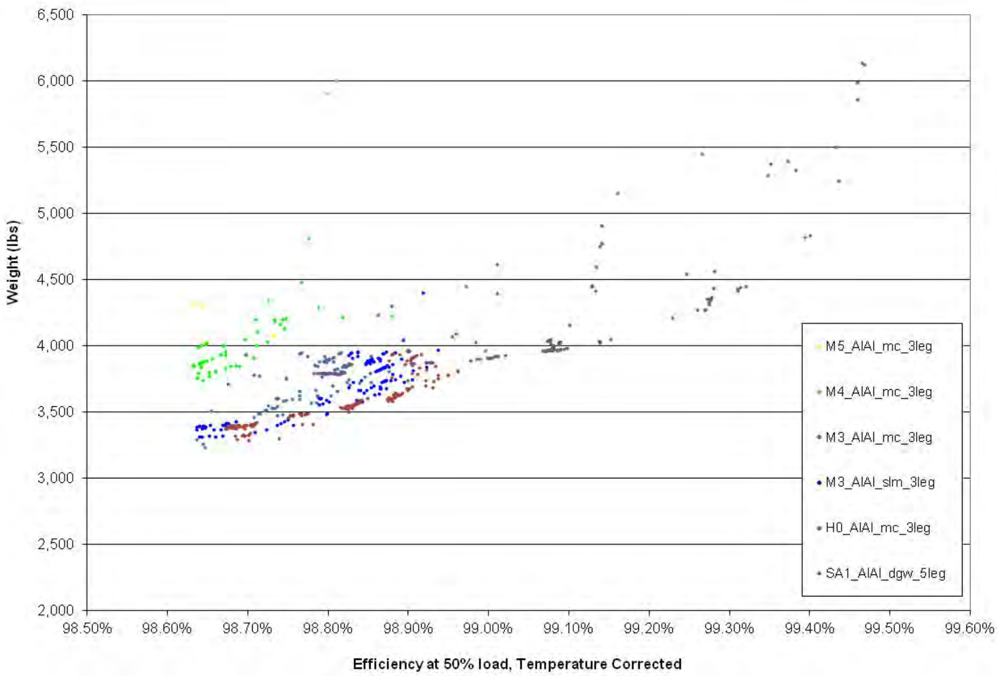

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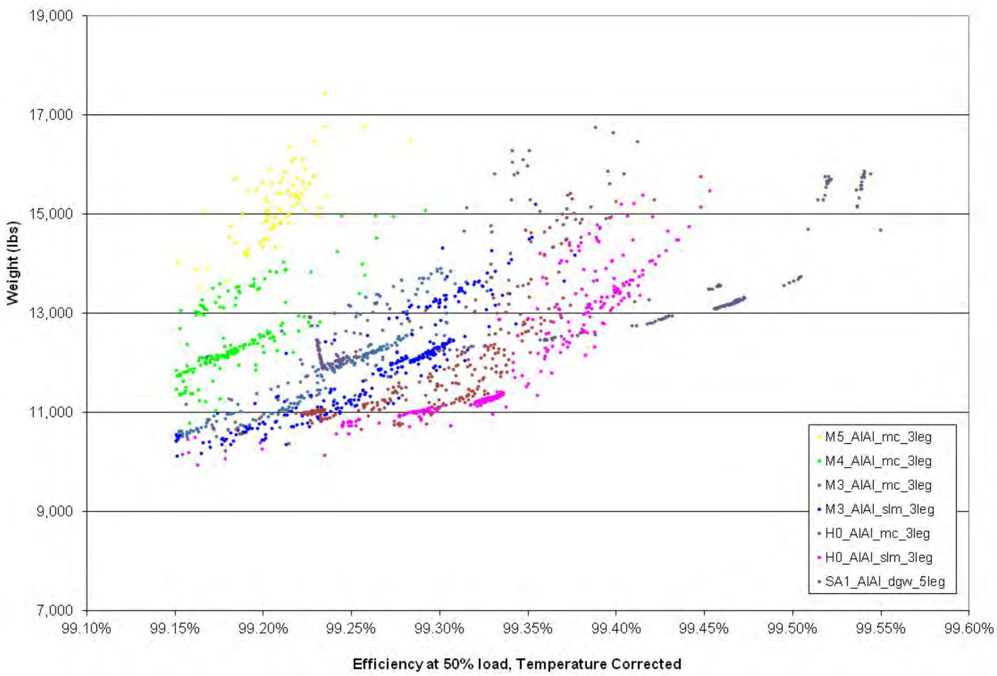

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APPENDIX 5B. SCALING RELATIONSHIPS IN TRANSFORMER MANUFACTURING

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APPENDIX 5B. SUPPLEMENTARY ENGINEERING ANALYSIS RESULTS

5B.1 INTRODUCTION

There exist certain fundamental relationships between the ratings in kilovolt-amperes (kVA) of transformers and their physical size and performance. A rather obvious such relationship is the fact that large transformers of the same voltage have lower percentage losses than small units, i.e., large transformers are more efficient. These size versus performance relationships arise from fundamental equations describing a transformer's voltage and kVA rating. For example, by fixing the kVA rating and voltage frequency, the product of the conductor current density, core flux density, core cross sectional area, and total conductor cross sectional area is constant.

To illustrate this point, consider a transformer with frequency, magnetic flux density, current density, and basic impulse insulation levels (BIL) all fixed. If one enlarges (or decreases) the kVA rating, then the only free parameters are the core cross section and the core window area through which the windings pass. Thus, to increase (or decrease) the kVA rating, the dimensions for height, width, and depth of the core/coil assembly may be scaled equally in all directions. Careful examination reveals that linear dimensions vary as the ratio of kVA ratings to the ¼ power. Similarly, areas vary as the ratios of kVA ratings to the ½ power and volumes vary as the ratio of the kVA ratings to the ¾ or 0.75 power. Hence the term "0.75 scaling rule." Table 5B.1 depicts the most common scaling relationships in transformers.

Table 5B.1 Common Scaling Relationships in Transformers

Parameter Being Scaled	**Relationship to kVA Rating (varies with ratio of kVA^x)**
Weight	$(kVA_1/kVA_0)^{3/4}$
Cost	$(kVA_1/kVA_0)^{3/4}$
Length	$(kVA_1/kVA_0)^{1/4}$
Width	$(kVA_1/kVA_0)^{1/4}$
Height	$(kVA_1/kVA_0)^{1/4}$
Total Losses	$(kVA_1/kVA_0)^{3/4}$
No-load Losses	$(kVA_1/kVA_0)^{3/4}$
Exciting Current	$(kVA_1/kVA_0)^{3/4}$
% Total Loss	$(kVA_1/kVA_0)^{-1/4}$
% No Load Loss	$(kVA_1/kVA_0)^{-1/4}$
% Exciting Current	$(kVA_1/kVA_0)^{-1/4}$
% Resistance (R)	$(kVA_1/kVA_0)^{-1/4}$
% Reactance (X)	$(kVA_1/kVA_0)^{1/4}$
Volts/Turn	$(kVA_1/kVA_0)^{1/2}$

The three elements listed below are true as the kVA rating increases or decreases, if the following factors are held constant: the type of transformer (distribution or power transformer, liquid filled or dry-type, single-phase or three-phase), the primary voltage, the core configuration, the core material, the core flux density, and the current density (amperes per square inch of conductor cross section) in both the primary and secondary windings.

1. The physical proportions are constant (same relative shape),
2. The eddy loss proportion is essentially constant, and
3. The insulation space factor (voltage or BIL) is constant.

In practical applications, it is rare to find that all of the above are constant over even limited ranges; however, over a range of one order of magnitude in both directions (e.g., from 50kVA to 5kVA or from 50kVA to 500kVA), the scaling rules shown in Table 5B.1 can be used to establish reasonable estimates of performance, dimensions, costs, and losses. In practice, these rules can be applied over even wider ranges to estimate general performance levels. The same quantities are depicted graphically in Figure 5B.1 for reference.

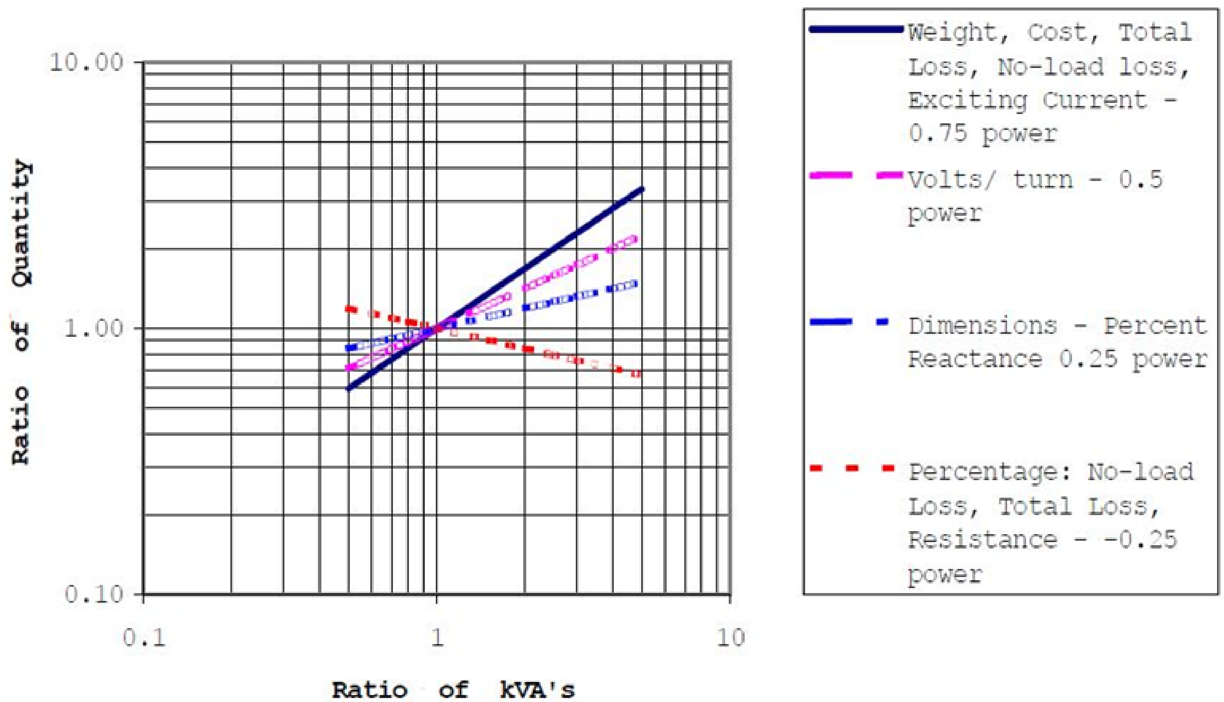

Figure 5B.1 Size and Performance Relationships by kVA Rating

To illustrate how the scaling laws are used, consider two transformers with kVA ratings of S_0 and S_1. The no-load losses (NL) and total losses (TL) of these two transformers would be depicted as NL_0 and TL_0, and NL_1 and TL_1. Then the relationships between the NL and TL of the two transformers could be shown as follows:

$$NL_1 = NL_0 \left(\frac{S_1}{S_0} \right)^{0.75} \quad \text{and} \quad TL_1 = TL_0 \left(\frac{S_1}{S_0} \right)^{0.75}$$

These two equations can be manipulated algebraically to show that the load loss also varies to the 0.75 power. Starting with the concept that total losses equals no-load losses plus load losses, one can derive the relationship for load loss (LL), and show that it also scales to the 0.75 power. Specifically:

$$\mathrm{LL}_1 = \mathrm{TL}_1 - \mathrm{NL}_1$$

Plugging the TL1 and NL1 terms into this equation:

$$\begin{aligned}\mathrm{LL}_1 &= \mathrm{TL}_0\left(\frac{\mathrm{S}_1}{\mathrm{S}_0}\right)^{0.75} - \mathrm{NL}_0\left(\frac{\mathrm{S}_1}{\mathrm{S}_0}\right)^{0.75} \\ &= \left(\mathrm{TL}_0 - \mathrm{NL}_0\right)\left(\frac{\mathrm{S}_1}{\mathrm{S}_0}\right)^{0.75}\end{aligned}$$

That is,

$$\mathrm{LL}_1 = \mathrm{LL}_0\left(\frac{\mathrm{S}_1}{\mathrm{S}_0}\right)^{0.75}$$

In this way, the 0.75 scaling rule can be used to derive the losses of a transformer, knowing the losses of a reference unit, if the specified type of transformer is held constant, and key parameters are fixed—such as the type of core material, core flux density, and conductor current density in the high and low voltage windings.

5B.2 THEORY AND BASIS FOR SCALING RULES

To understand the origins of winding and output coefficients and related scaling laws, it is necessary to review some basic equations and definitions. Most are lifted freely or derived from similar material in *Modern Power Transformer Practice*, Wiley 1979, edited by R. Feinberg.[i] No mathematics beyond elementary algebra is required, but a good deal of implied physics and electrical engineering is required to fully appreciate these derivations.

5B.2.1 Power and Voltage Equations

The machine equation relates the induced volts, V, per phase to the number of turns (N) the frequency (f) in Hertz, the peak core flux density B_m in Tesla, and the cross-sectional area of the core steel (A_{Fe}) in square meters. The units are mixed to simplify the basic equations, a common practice in transformer design texts. The machine equation is derived from Faraday's law, which is expressed as

$$v = -N\frac{\partial \phi}{\partial t}$$

where v is the instantaneous value of V, and — is the derivative of changing magnetic flux with respect to time.

Considering V as the root-mean-square (RMS) value of a sine-wave alternating current voltage, the above equation can be converted into:

$$V/N = 4.44fB_mA_{Fe}$$

Equation 5B.1

The voltage and turns may apply to either the primary or the secondary winding and, for the ideal transformer with no losses and no-leakage flux,

$$V_1/V_2 = N_1/N_2 = n = I_2/I_1$$

where V_1 and V_2 represent primary and secondary voltages respectively, N_1 and N_2 primary and secondary turns, and I_1 and I_2 primary and secondary currents in amperes (amps). The quantity n is referred to as the "turns ratio." With the parameters defined, and using Equation 5B.1, the output or transformer capacity (S) in megavolt-amperes (MVA) per phase can be expressed as:

$$S = 4.44fB_mA_{Fe}NI$$

Equation 5B.2

The overall cross-section of primary plus secondary conductors in square meters is

$$A_{Cu} = \left(N_1a_1 + N_2a_2\right)\times 10^{-6}$$

and, assuming current densities for primary and secondary windings to be equal, then

$$A_{Cu} = 2\times 10^{-6}\ Na$$

where "a" is the conductor cross-section in square millimeters (mm^2) of an individual turn referred to the winding with N turns, and a_1 and a_2 are conductor cross-sections of primary and secondary turns, respectively. As long as the winding current densities are equal, either winding may be used as reference, provided the choice of primary or secondary is consistent. Starting with Equation 5B.2, using the A_{Cu} relationship explained above, and letting J represent current density in amps per mm^2:

$$S = 2.22\, f\, B_m\, J\, A_{Fe}\, A_{Cu}$$

Equation 5B.3

Let A_w be the core window area in square meters, and k_w the window space factor, as given by . (Refer to Figure 5B.3 and note that, in a three-phase transformer, there are two coil phases occupying a given core window). This fraction is indicative of the insulation and cooling channel requirements. For distribution transformers, k_w is found to be about 0.3–0.4 for nominal 12 kV systems. Using these definitions,

$$S = 1.11\, f\, B_m J\, A_{Fe}\, k_w A_w$$

Equation 5B.4

Note that, for a given MVA rating, and specified flux and current densities, the product of conductor and core cross-section is constant and inversely related; i.e. $A_{Fe}\ \alpha\ 1/A_{Cu}$.

5B.2.2 Losses

Ideally, if the values of energy loss in Watts per kilogram (W/kg) of unit mass of the core and windings are known, the total core and load losses (P_{Fe} and P_{Cu}) can be readily obtained. These results are accomplished by multiplying the W/kg for both core and windings by the core mass and the conductor mass respectively (or by their volumes times material densities).

The Department uses the convention that lower case corresponds to per-unit quantities and upper case corresponds to total or total-per-phase quantities. Load losses consist of resistive (P_R) and eddy (P_i) components. Expressions can be derived that express each in terms of the conductor properties and geometry. The fraction of eddy losses plays an important role and can be expressed as

$$\%P_i = 100\ P_i/P_R,\ \text{or}\ P_i = P_R\left(\frac{\%P_i}{100}\right)$$

Ignoring stray loss, (which is associated with eddy losses), let P_t represent total load loss for a three-phase transformer. That is,

$$P_t = 3P_{Cu}$$

Also assume the same eddy loss fraction in primary and secondary windings.

$$P_{Cu} = P_R + P_i = P_R + P_R\left(\frac{\%P_i}{100}\right) = \left(1 + \frac{\%P_i}{100}\right)P_R = k_i P_R$$

Closely associated with the load loss of a transformer is its impedance. When the load loss of a given transformer is determined by test (the wattmeter reading in the test circuit), that same test also provides the value of the impedance (the voltmeter reading in the test circuit). Impedance in a transformer is expressed in terms of the “impedance voltage,” which is defined as “the voltage required to circulate rated current through one of two specified windings of a transformer when the other winding is short-circuited, with the windings connected as for rated voltage operation” (IEEE C57.12.80).

For convenience, “percent impedance,” %Z, is used to describe the impedance voltage of a transformer. In accordance with the definition given above,

$$\%Z = \frac{IZ \times 100}{V}$$

that is, when related to the primary or secondary winding of a transformer, the percent impedance is the percent voltage drop due to impedance when rated current flows through the respective primary or secondary winding of the transformer.

The %Z may be represented by its resistive and reactive components, %R and %X, as

$$\%Z = \sqrt{(\%R)^2 + (\%X)^2}$$

Therefore, one can express percent resistance (%R) as follows:

$$\%R = \frac{IR \times 10^2}{V}$$

Note that R in the numerator must represent the total resistance in the transformer windings. Therefore, if the transformer is being viewed from the primary terminals, the value of R would be the total resistance of the primary winding, plus the total resistance of the secondary winding referred to the primary winding, $(R_2(N_1/N_2)^2)$.

Where the percent impedance, percent reactance, and percent resistance are related to the voltage across the primary or secondary winding of a transformer, the percent load loss ($\%I^2R$) is related to the MVA capacity of the transformer, stray loss being ignored as stated previously.

Multiplying numerator and denominator in the above equation by I, and letting P_t represent total load loss in watts and S represent the MVA per phase rating, one can determine the percent load loss as:

$$\text{Percent load loss} = \frac{I^2R \times 10^2}{I \times V} = \frac{I^2R \times 10^2}{3S \times 10^6}$$

$$\therefore \%R = \frac{10^{-4} P_t}{3S}$$

Thus, an expression of %R is equivalent to indicating the transformer's load loss.

From Equation 5B.3, it is evident that, once the core flux density and current density are fixed, the transformer rating is dependent on the core cross-section and window area. Next, one can derive information about the window shape.

In a detailed discussion of the reactance, the electrical characteristics would depend on:

- The ratio of winding height (h) to the winding mean turn(s), and
- The ratio of the cross-sectional areas of the core and conductor (A_{Fe}/A_{Cu}).

The mean value of s (a linear measurement, recording the circumference), is given by the equation $s = (s_1 + s_2)/2$, where s_1 is the mean turn of the primary winding and s_2 is the mean turn of the secondary winding.

These ratios, together with the necessary space factors for insulating and cooling clearances, establish the relative volumes of the core and conductor. Consequently, if fixed values for the specific loadings and, therefore specific losses for core and conductor can be assumed, the ratios of core loss and load loss are established.

The following application of relationships derives an expression relating the flux and current densities. The expression starts with:

$$P_{Cu} = \left(1 + \frac{\%P_i}{100}\right)P_R = k_i P_R$$
$$P_{Cu} = \left(I_1{}^2 R_1 + I_2{}^2 R2\right)k_i,$$

where subscripts 1 and 2 indicate primary and secondary windings, respectively. The resistance per phase of the primary winding is given by

$$R_1 = \frac{\rho N_1 s_1}{a_1}\,\text{ohms},$$

where a_1 is the cross-sectional area of the primary copper conductor, and ρ is the resistivity at full load operating temperature of the conductor, 21.4 x 10^{-3} ohm-meters. The value of R_2 is similarly obtained:

$$\therefore P_{Cu} = \left(\frac{I_1{}^2 \rho N_1 s_1}{a_1} + \frac{I_2{}^2 \rho N_2 s_2}{a_2}\right)k_i$$

$$\therefore P_{Cu} = IN\left(\frac{I_1 s_1}{a_1} + \frac{I_2 s_2}{a_2}\right)\rho k_i$$

where IN is the ampere-turns in either winding. As before, the assumption of equal current densities in the windings is made, driven by the condition for minimum I^2R loss. Accordingly,

$$P_{Cu} = 2INJs\rho k_i$$
$$\therefore J = \frac{P_{Cu}}{2INsk_i\rho}\text{, the current density equation.}$$

Multiplying Equation 5B.1 by I and rearranging algebraically, one gets:

$$IN = \frac{VI}{4.44fB_m A_{Fe}}$$

It was established earlier that S is the rating per phase in MVA, i.e., VI = 10^6S. Thus:

$$\therefore IN = \frac{10^6 S}{4.44 f B_m A_{Fe}}$$

Using the current density equation, substituting the resistivity value for ρ, and the above value for IN, one can derive that:

$$J = \frac{104 \times 10^{-6} f B_m A_{Fe} P_{Cu}}{k_i s S}$$

The watts of conductor loss (for copper) can be expressed as a percentage of the transformer MVA rating:

$$\%P_{Cu} = \frac{P_{Cu} \times 10^2}{S}$$

or, in kilowatts:

$$\%P_{Cu} = \frac{P_{Cu} \times 10^2}{S \times 10^3} = \frac{0.1 P_{Cu}}{S}$$

By substituting in the revised equation for J (amperes per square meter), one gets

$$J = \frac{104 \times 10^{-6} f B_m A_{Fe} S}{k_i s S} \times \frac{\%P_{Cu}}{0.1} = \frac{1040 \times 10^{-6} f B_m A_{Fe}}{k_i s} \times \%P_{Cu}$$

Equation 5B.5

If aluminum windings were used instead of copper, a value of 655 would be substituted for 1040. The expression assumes equal J in both windings, and that both windings are made of the same material. The losses are expressed at operating temperature.

If J and B_m are chosen independently, the transformer will have a natural value of conductor loss depending on the ratio A_{Fe}/s. Conversely, if losses are specified, the choice of J is determined by B_m and A_{Fe}/s. Note that this relationship gives no information about the other transformer dimensions. The impedance, voltage, and other space requirements provide the majority of this information.

5B.2.3 Output and Winding Coefficients

Starting with the output or power Equation 5B.3, one can write:

$$S = 2.22fB_m JA_{Fe}A_{Cu} \text{ or } A_{Fe} = \frac{S}{2.22fB_m JA_{Cu}}$$

Then, without changing the value, one can state:

$$A_{Fe} = \sqrt{\frac{S^2}{\left(2.22fB_m JA_{Cu}\right)^2}} = \sqrt{S}\sqrt{\frac{2.22fB_m J\left(A_{Fe}\right)\left(A_{Cu}\right)}{\left(2.22fB_m JA_{Cu}\right)^2}} \text{ or}$$

$$A_{Fe} = \sqrt{S}\sqrt{\frac{A_{Fe}}{\left(2.22fB_m J\right)\left(A_{Cu}\right)}}$$

Equation 5B.6

Use K_{AS} to represent the portion of Equation 5B.6 to the right of

The expression K_{AS} is essentially constant for a wide range of transformer classes and is called the output coefficient. For three-phase, liquid-filled distribution transformers at 60 Hz, the value of K_{AS} ranges from 0.050 to 0.055, with a nominal median value of 0.052. For single-phase, wound-core, liquid-filled units at 60 Hz, the median value is about 0.040.

In a similar fashion, making use of Equation 5B.6, we can restate Equation 5B.1 as follows:

$$\frac{V}{N} = 4.44fB_m A_{Fe} = \sqrt{\frac{\left(4.44fB_m\right)^2 A_{Fe}}{2.22fB_m JA_{Cu}}}$$

$$= \sqrt{\left(\frac{8.88fB_m}{J}\right)\left(\frac{A_{Fe}}{A_{Cu}}\right)(S)} = K_{VS}\sqrt{S}$$

Equation 5B.7

The expression K_{VS} is also essentially constant for a wide range of transformer classes and is called the winding coefficient. One can also express K_{VS} in terms of K_{AS}:

$$K_{VS} = 4.44fB_m K_{AS}$$

For 60 Hz systems, this may be rewritten as K_{VS}= 266.4 $B_m K_{AS}$. Thus the median values for K_{VS} become 21.5 for three-phase and 17.0 for single-phase, wound-core distribution transformers at 60 Hz with B_m = 1.55 Tesla. Equation 5B.6 and Equation 5B.7 provide initial estimates for transformer dimensions in studies. They are the starting basis for the scaling laws used to scale designs and performance. Typical values are given in Table 5B.2.

Table 5B.2 Nominal 60 Hz, Core-Type, Liquid-Filled, 12 kV Distribution Transformer

Class of Dist.	$J(A/mm^2)$		B_m (Tesla)	A_{Fe}/A_{Cu}		K_{AS}		K_{VS}	%X
Transf.	Range	Nominal	Nominal	Range	Nominal	Range	Nominal		
3-Phase	2.4-3.2	2.7	1.55	1.4-2.8	1.6	0.050-0.055	0.052	21.5	4.75
1-Phase	2.0-2.5	2.3	1.55	0.65-0.85	0.8	0.038-0.043	0.041	17.0	4.75

5B.2.4 Scaling Laws

Having established the output and winding coefficients, it is instructive to examine the origin of the 0.75 rules for scaling transformer losses. To illustrate, first of all, one needs to set relationships as follows:

$$\frac{V}{N} = K_{VS}\sqrt{S}$$

$$A_{Fe} = K_{AS}\sqrt{S}$$

$$A_{Cu} = K_{CS}\sqrt{S}\ ,\ \left(\text{where } K_{CS} = \frac{1}{K_{AS}}\right)$$

$$s \sim \left(A_{Fe}{}^{0.5} + \frac{b_w}{4}\right) \sim s^{0.25}$$

The shape of the window is set by voltage and the ratio h/s, which is essentially constant for a given voltage and size, thus setting b_w. Refer to Figure 5B.3 for dimensional definitions.

Now, one considers the load losses, P_{Cu} (in kW/phase):

$$P_{Cu} = \frac{I^2 R}{1000} = \left(\frac{S}{V}\right)^2 \frac{R}{1000}$$

$$= \frac{4.28\times10^{-17} S^2 sN}{A_{Cu}V^2} = K\sqrt{S}\times s = K'S^{0.75}$$

The other scaling laws are derived in a similar fashion.

5B.2.5 Deviations from .75

Although these laws dictate that an ideal transformer will yield a scaling exponent of 0.75, DOE recognizes that a different exponent may produce better behaved results based on real-world engineering. For the NOPR, DOE used unique scaling exponents for each equipment class. For each equipment class DOE derived an exponent to scale relative kVA rating by examining the proposals discussed during the negotiations. Because the proposals discussed during the negotiations included efficiency levels across multiple designs lines, a scaling relationship was implied by the proposal. The exponents used for each equipment class are shown below in Table 5B.3.

If one imagines the standard for a particular equipment class as a function on a plot of efficiency (y-axis) versus kVA (x-axis), then the efficiency levels in each design line are a series of points along an imaginary vertical line that intersects the x-axis at the design line's kVA. If there is more than one design line in a given equipment class, there will be more than one series of points. Because exponential scaling is performed on losses and because exponential function will appear as straight lines on logarithmic plots, the concept is more tractable if illustrated that way, as is done in Figure 5B.2 below. Note that efficiency and loss values have a one-to-one correspondence with each other, so one can use whichever coordinate is easier to illustrate identical information. Although standards are ultimately given in terms of efficiency, DOE performs the scaling in loss coordinates. Also note that the following figures are given to illustrate the scaling concept, and have no relation to actual transformer data.

If one is to select efficiency levels for each design line, as was done by the negotiating committee for MVDT transformers, the task remains to scale those chosen efficiencies at certain kVA ratings to all of the other kVA ratings that DOE covers. Drawing a straight line[1] through the chosen points accomplishes that goal, but may produce a slope different from .75.

Deriving the .75 rule requires a number of assumptions to be made, among them that the overall form and proportions of the transformer remain intact as it changes in size. This assumption may break down in a number of ways. For example, MVDT BIL ratings require fixed spacings between the edge of a winding and the window of a core. Proportionally, these fixed values will be much larger for smaller transformers than for larger units. Thus, while the rest of the transformer may behave closer to what the .75 rule would predict, the "fixed" portion will cause losses to fall more slowly with decreasing kVA. Stated alternatively, losses will grow more slowly with increasing kVA and imply a scaling behavior of less than .75.

[1] A straight line in logarithmic space is an exponential in the original dimensions, which is the logical scaling behavior for transformers to exhibit.

Figure 5B.2 Efficiency Levels within an Equipment Class (Logarithmic)

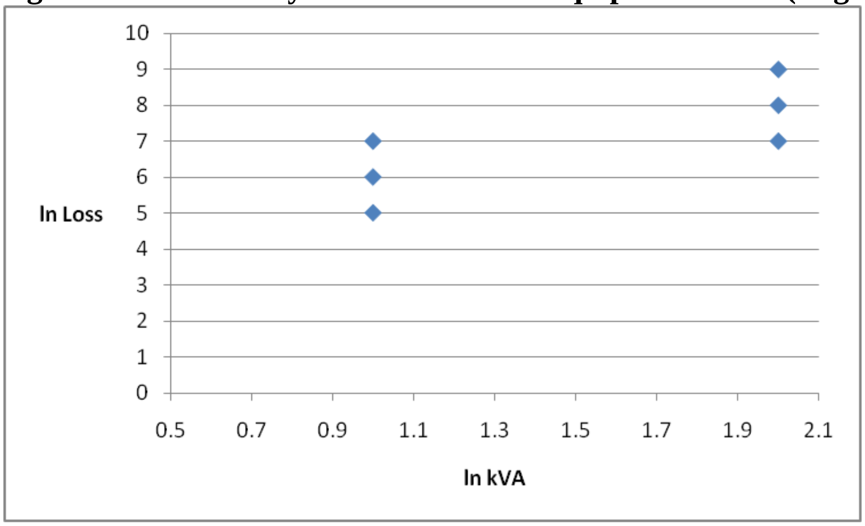

Table 5B.3 Scaling Exponents By Equipment Class

Distribution Transformer Equipment Class	Scaling Exponent
1. Liquid-immersed, medium-voltage, single-phase	.76
2. Liquid-immersed, medium-voltage, three-phase	.79
3. Dry-type, low-voltage, single-phase	.75
4. Dry-type, low-voltage, three-phase	.67
5. Dry-type, medium-voltage, single-phase, 20-45 kV BIL	.67
6. Dry-type, medium-voltage, three-phase, 20-45 kV BIL	.67
7. Dry-type, medium-voltage, single-phase, 46-95 kV BIL	.67
8. Dry-type, medium-voltage, three-phase, 46-95 kV BIL	.67
9. Dry-type, medium-voltage, single-phase, $\geq$ 96 kV BIL	.68
10. Dry-type, medium-voltage, three-phase, $\geq$ 96 kV BIL	.68

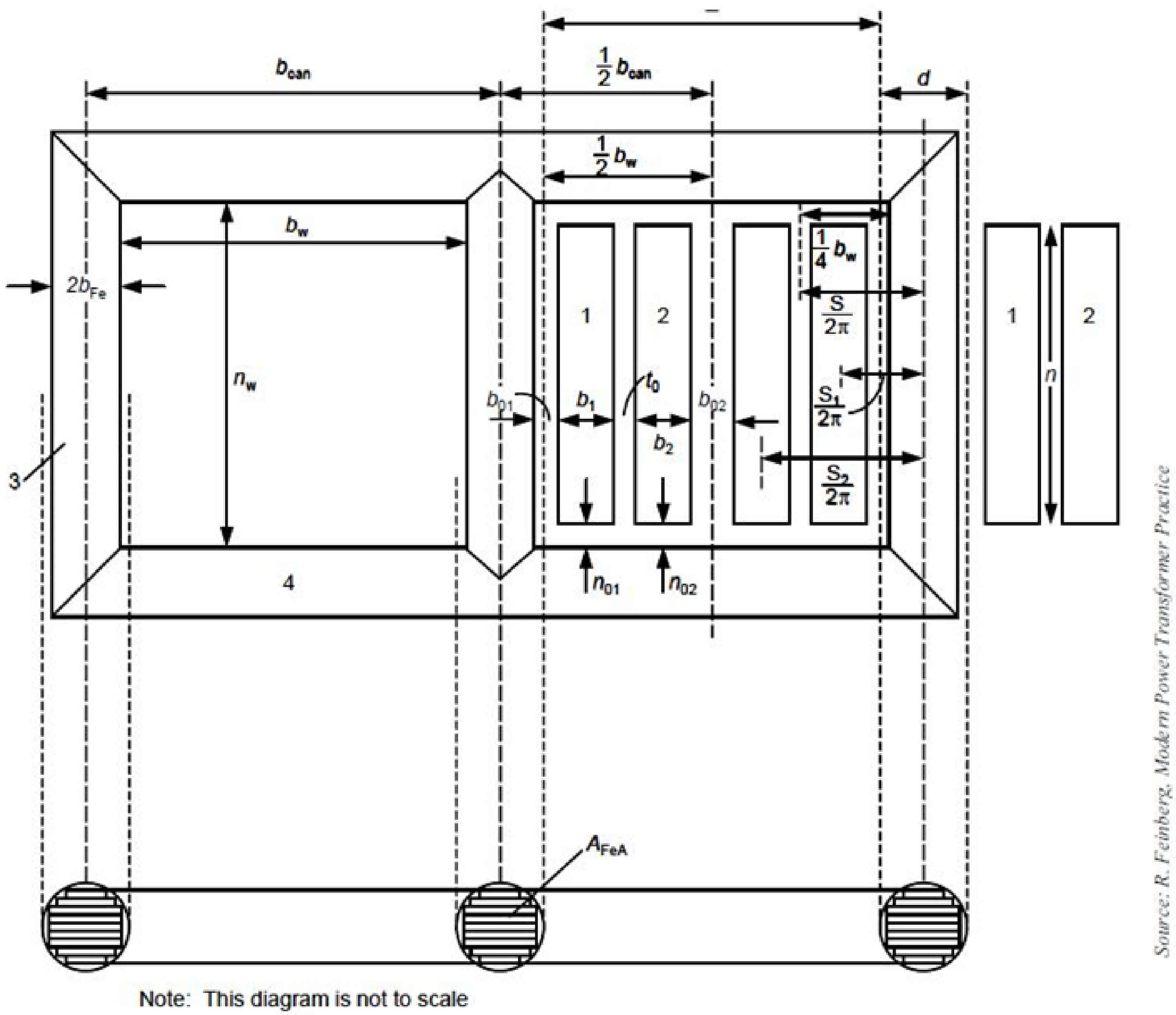

Figure 5B.3 Basic Three-Phase Transformer Dimensions

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[i] Modern power transformer practice, Edited by R Feinberg, Wiley Publishers, New York, NY, 1979. ISBN: 047026344X

APPENDIX 5C. 2008 MATERIAL PRICING ANALYSIS

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APPENDIX 5C. 2008 MATERIAL PRICING ANALYSIS

5C.1 INTRODUCTION

Core steel is one of the major cost drivers of a distribution transformer and is fundamentally linked to the efficiency of the finished transformer. When looking at energy conservation standards for distribution transformers, it is important to understand core steel pricing and influences on that pricing. Therefore, in addition to its analysis using the current 2011 material price, the Department of Energy (DOE) conducted a “high” price sensitivity analysis using the material prices from 2008, which represent a high price point over the 2006-2011 timeframe. The results of the 2011 material price reference case are presented in Chapter 5 of the technical support document (TSD). The results of the 2008 (high) material price sensitivity analysis are presented in this appendix for the reference case engineering analysis designs. DOE does not present 2008 material price sensitivities for the symmetric core or supplementary aluminum conductor designs. All material prices are expressed in terms of 2010$.

The life-cycle cost (LCC) results for the 2008 material price scenario can be found in TSD Appendix 8E, which presents DOE’s sensitivity analyses conducted on various LCC inputs, including material prices. In Chapter 8, the 2008 material price is referred to as the “high” price scenario and the 2011 price scenario is called the “medium” price scenario. DOE also created a “low” price scenario to establish a lower bound for the LCC sensitivity analysis. It based the low price scenario on material prices in 2006 (the calendar year with the lowest $/pound for most core steels). These material prices can be found in the material price tables in Chapter 5, and the low-price scenario manufacturer selling prices can be found in the LCC spreadsheets.

5C.2 MATERIAL PRICING TABLES

DOE completed a supplementary engineering analysis using 2008 material prices. The following table presents the 2011 reference case and the 2008 sensitivity of high material prices used for liquid-immersed units.

Table 5C.1 Liquid-Immersed Material Prices Used in the Engineering Analyses

Material	Units	2011 Price *2010$*	2008 Price (Max.) *2010$*
M6 core steel	*$/lb*	1.04	2.19
M5 core steel	*$/lb*	1.10	2.24
M4 core steel	*$/lb*	1.20	2.30
M3 core steel	*$/lb*	1.30	2.60
M3 core steel (Lite Carlite)	*$/lb*	1.95	2.44
M2 core steel	*$/lb*	1.40	2.79
M2 core steel (Lite Carlite)	*$/lb*	2.10	2.63
ZDMH (mechanically-scribed core steel)	*$/lb*	1.90	3.22
SA1 (amorphous) finished core, volume production	*$/lb*	2.20	3.64
Copper wire, formvar, round #10-20	*$/lb*	4.87	5.97
Copper wire, enameled, round #7-10	*$/lb*	4.84	5.93
Copper wire, enameled, rectangular sizes	*$/lb*	4.97	6.09
Aluminum wire, formvar, round #9-17	*$/lb*	3.07	3.91
Aluminum wire, formvar, round #7-10	*$/lb*	2.57	3.28
Copper strip, thickness range 0.02-0.045	*$/lb*	4.97	6.09
Copper strip, thickness range 0.030-0.060	*$/lb*	4.97	6.09
Aluminum strip, thickness range 0.02-0.045	*$/lb*	2.08	2.67
Aluminum strip, thickness range 0.045-0.080	*$/lb*	2.08	2.67
Kraft insulating paper with diamond adhesive	*$/lb*	1.52	1.93
Mineral oil	*$/gal*	3.35	3.84
Tank Steel	*$/lb*	0.38	0.60

Likewise, DOE used material prices from the 2008 sensitivity price analysis to conduct an additional engineering analysis for dry-type units. The following table presents the 2011 reference case and 2008 sensitivity of high material prices used for dry-type units.

Table 5C.2 Dry-Type Material Prices Used in the Engineering Analyses

Material	Units	2011 Price *2010$*	2008 Price (Max.) *2010$*
M12 core steel	*$/lb*	0.84	0.66
M6 core steel	*$/lb*	1.19	0.91
M5 core steel	*$/lb*	1.60	0.78
M4 core steel	*$/lb*	2.19	1.04
M3 core steel	*$/lb*	2.24	1.10
M2 core steel	*$/lb*	2.30	1.20
H-0 DR core steel (laser scribed)	*$/lb*	2.60	1.30
SA1 (amorphous) finished core, volume production	*$/lb*	2.79	1.40
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped	*$/lb*	3.23	1.70
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped	*$/lb*	3.64	2.20
Copper strip, thickness range 0.02-0.045	*$/lb*	5.53	4.52
Aluminum strip, thickness range 0.02-0.045	*$/lb*	3.78	2.97
Nomex insulation	*$/lb*	6.09	4.97
Cequin insulation	*$/lb*	2.67	2.08
Impregnation	*$/gal*	29.03	24.50
Winding combs	*$/lb*	6.09	5.53
Enclosure Steel	*$/lb*	27.31	22.55

DOE used the same markup percentages for both engineering analyses, including markups of 2.5 percent for the scrap factor, 4 percent for additional scrap due to the core steel mitering process, 12.5 percent for factory overhead, $0.22 per pound for shipping costs, and 25 percent for non-production costs.

5C.3 2008 MATERIAL PRICE ENGINEERING ANALYSIS RESULTS

This section provides a visual representation of the results of the 2008 material pricing analysis. The scatter plots in this section show the relationship between the manufacturer's selling price and efficiency relationships for each of the 13 design lines. Each dot on the plots represents one unique design created by the software at a given manufacturer's selling price and efficiency level. The placement of each dot (and the uniqueness of each design) is dictated by the design option combinations (core steel and windings), core shape, and combination of A and B factors (the capitalized cost per watt of no-load and load losses).

Additional scatter plots within each subsection illustrate the manufacturer selling price delta between transformer designs using 2011 material prices and 2008 material prices. Each scatter plot also visually presents the candidate standard levels chosen for consideration by DOE for that particular design line.

5C.2.1 Design Line 1 Engineering Analysis Results

Figure 5C.1 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 1. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

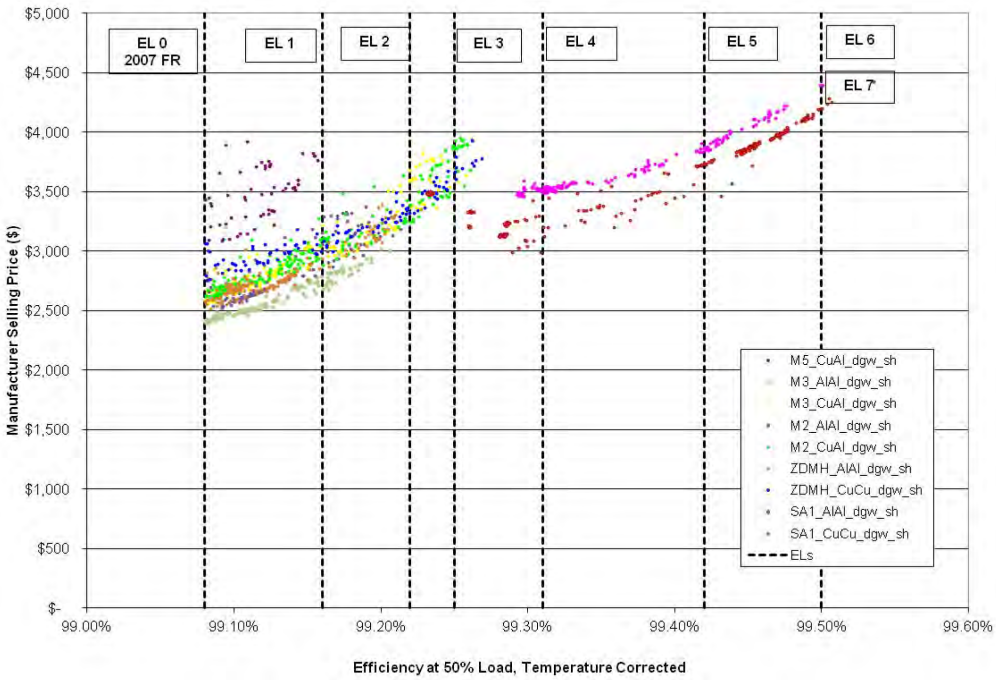

Figure 5C.1 Price and Efficiency for 2008 Material Sensitivity, Design Line 1

Figure 5C.2 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 1 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

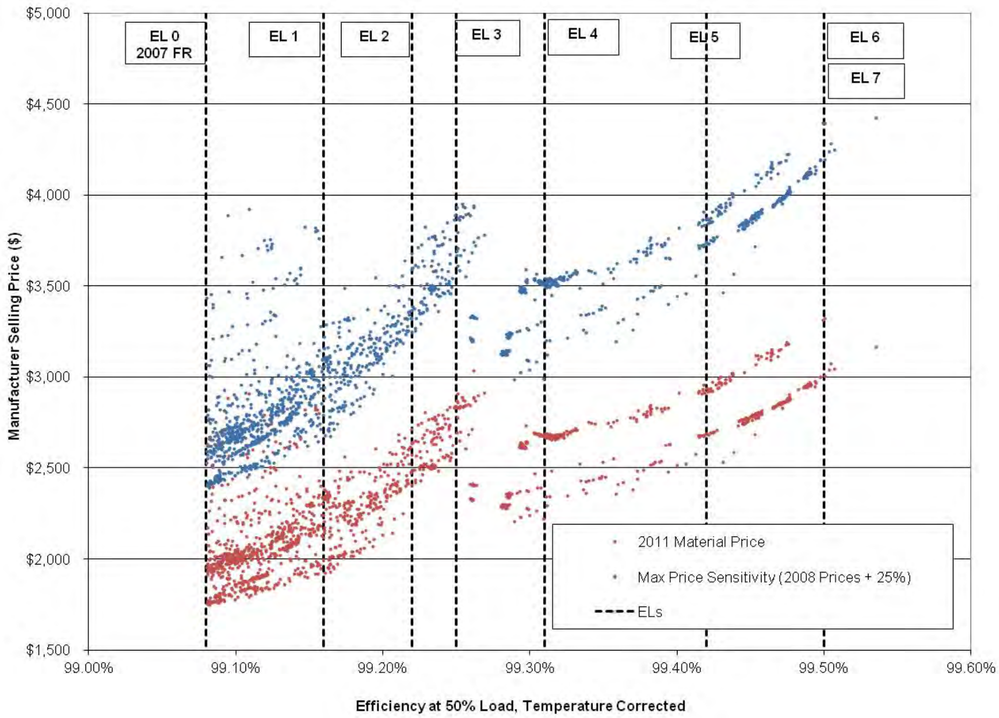

Figure 5C.2 Material Price Scenario Comparison Plot, Design Line 1

5C.2.2 Design Line 2 Engineering Analysis Results

Figure 5C.3 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 2. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

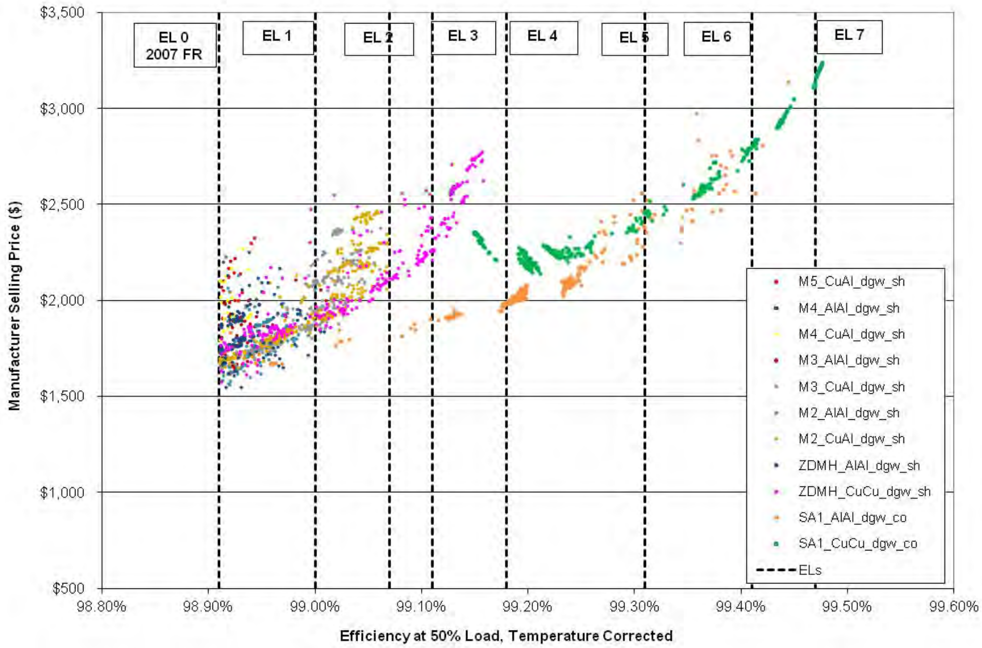

Figure 5C.3 Price and Efficiency for 2008 Material Sensitivity, Design Line 2

Figure 5C.4 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 2 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

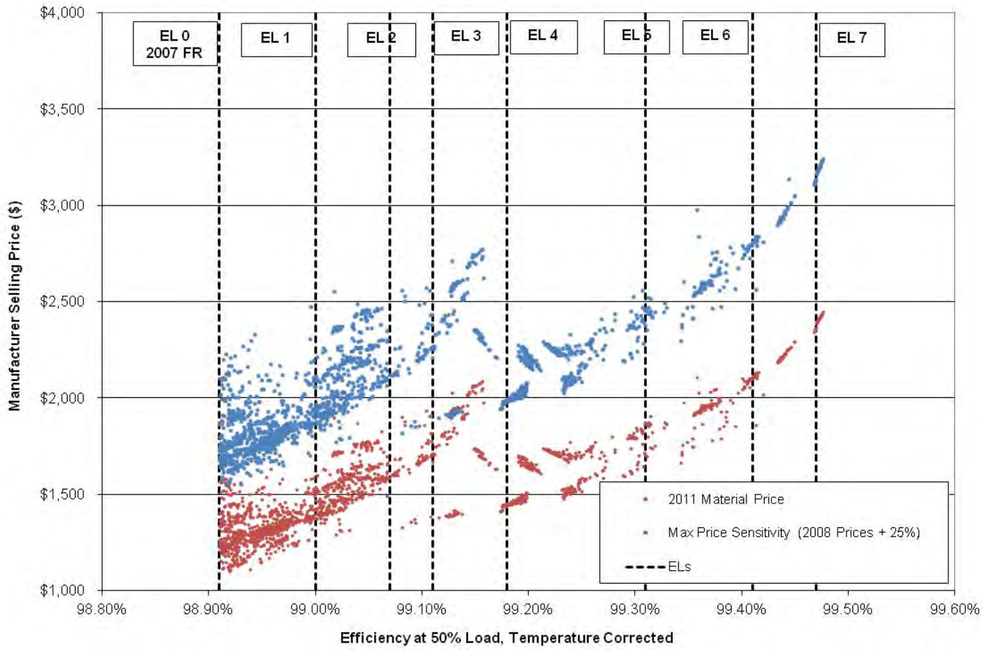

Figure 5C.4 Material Price Scenario Comparison Plot, Design Line 2

5C.2.3 Design Line 3 Engineering Analysis Results

Figure 5C.5 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 3. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

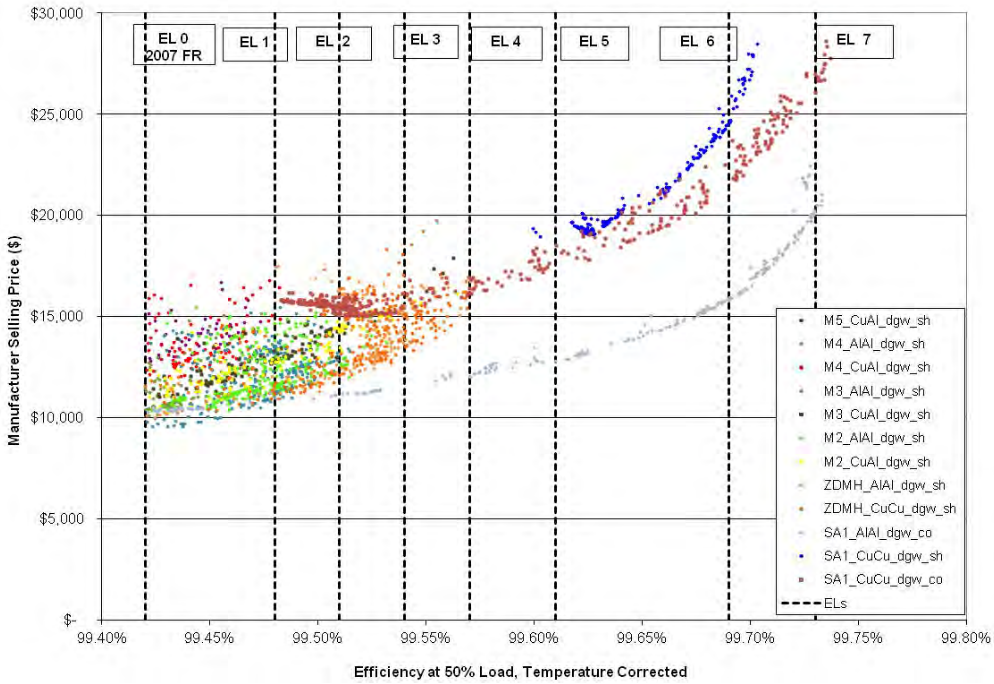

Figure 5C.5 Price and Efficiency for 2008 Material Sensitivity, Design Line 3

Figure 5C.6 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 3 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

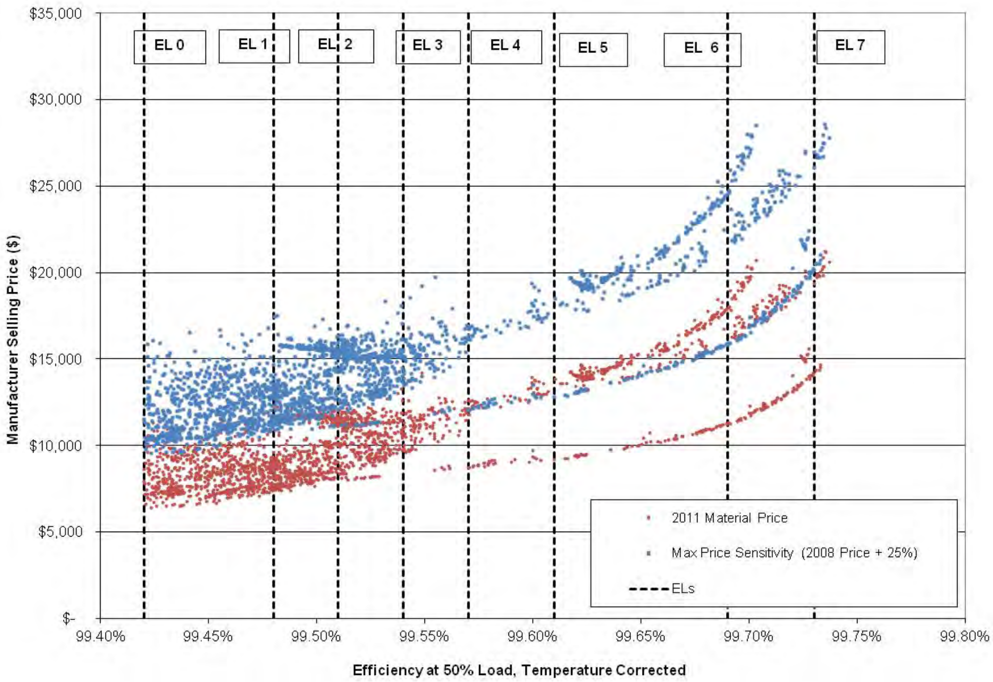

Figure 5C.6 Material Price Scenario Comparison Plot, Design Line 3

5C.2.4 Design Line 4 Engineering Analysis Results

Figure 5C.7 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 4. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

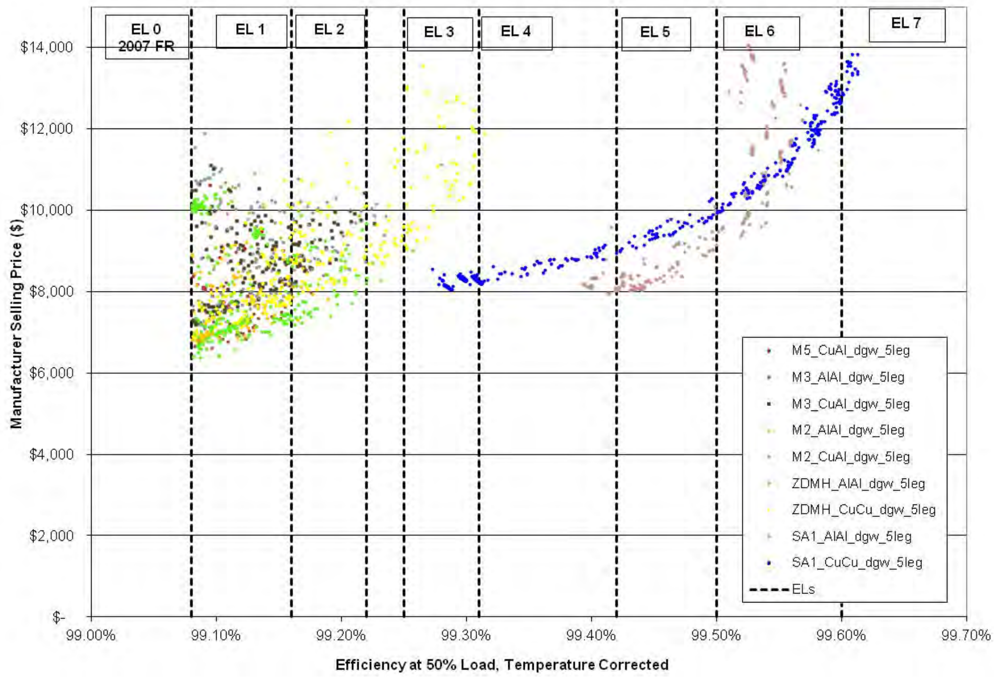

Figure 5C.7 Price and Efficiency for 2008 Material Sensitivity, Design Line 4

Figure 5C.8 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 4 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

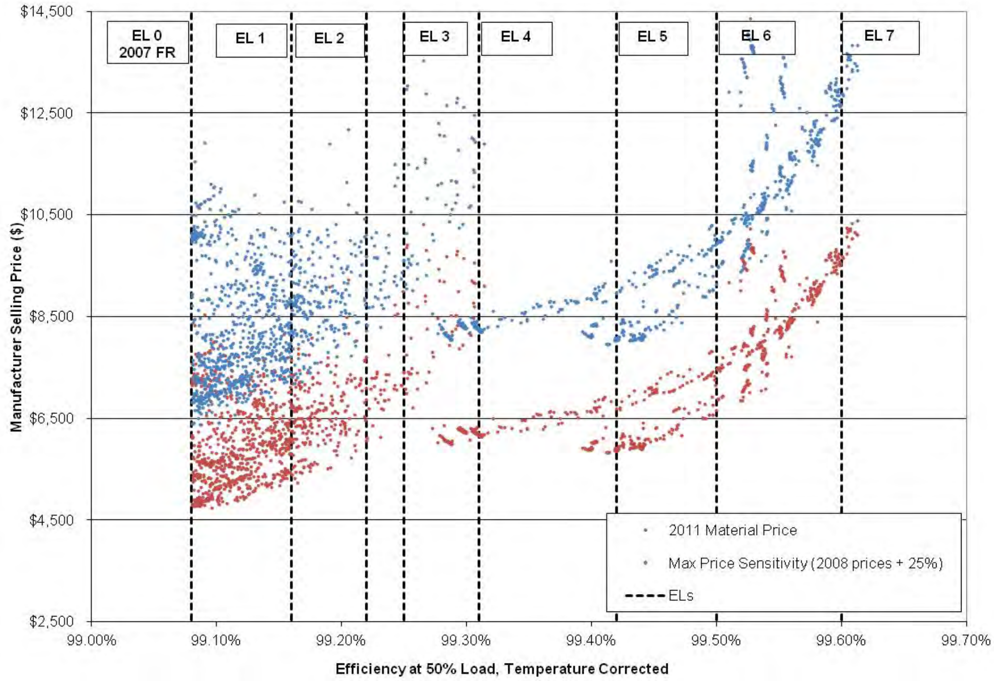

Figure 5C.8 Material Price Scenario Comparison Plot, Design Line 4

5C.2.5 Design Line 5 Engineering Analysis Results

Figure 5C.9 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 5. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

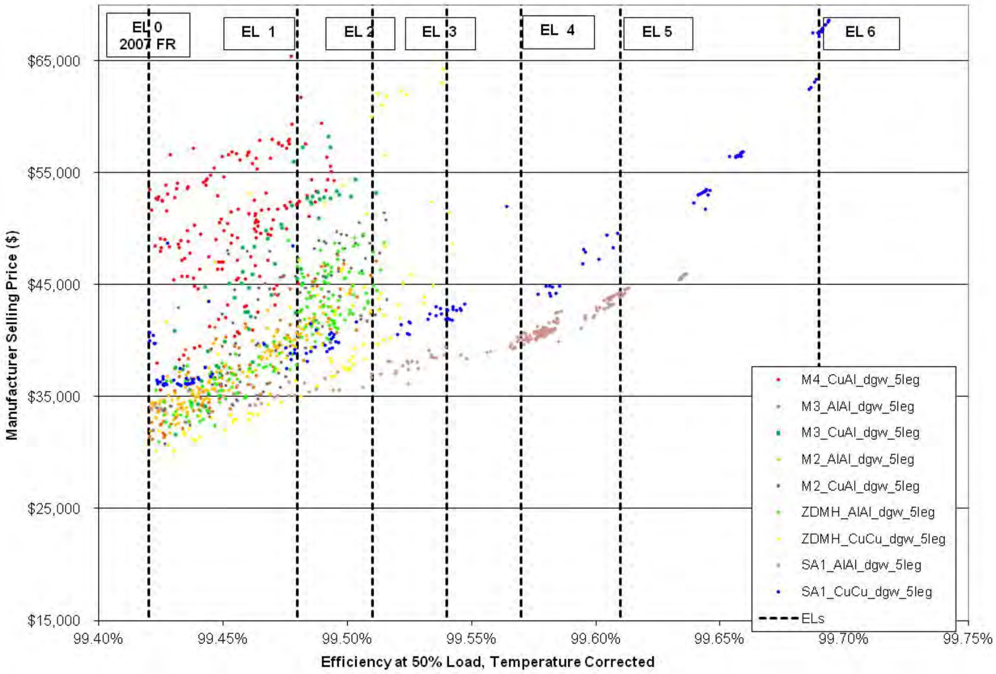

Figure 5C.9 Price and Efficiency for 2008 Material Sensitivity, Design Line 5

Figure 5C.10 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 5 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

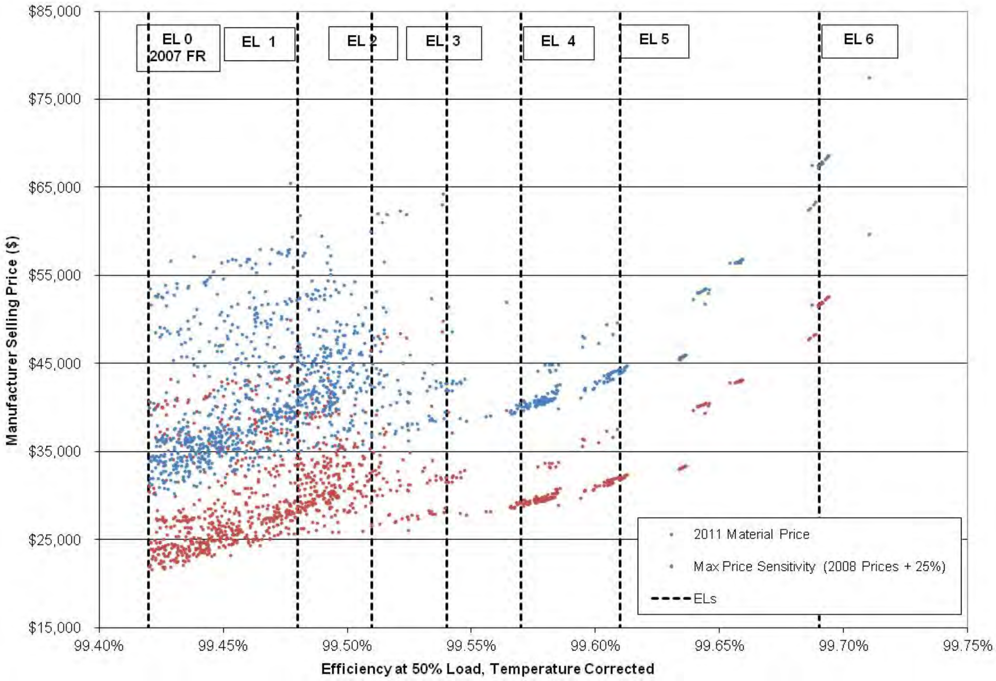

Figure 5C.10 Material Price Scenario Comparison Plot, Design Line 5

5C.2.6 Design Line 6 Engineering Analysis Results

Figure 5C.11 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 6. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature.

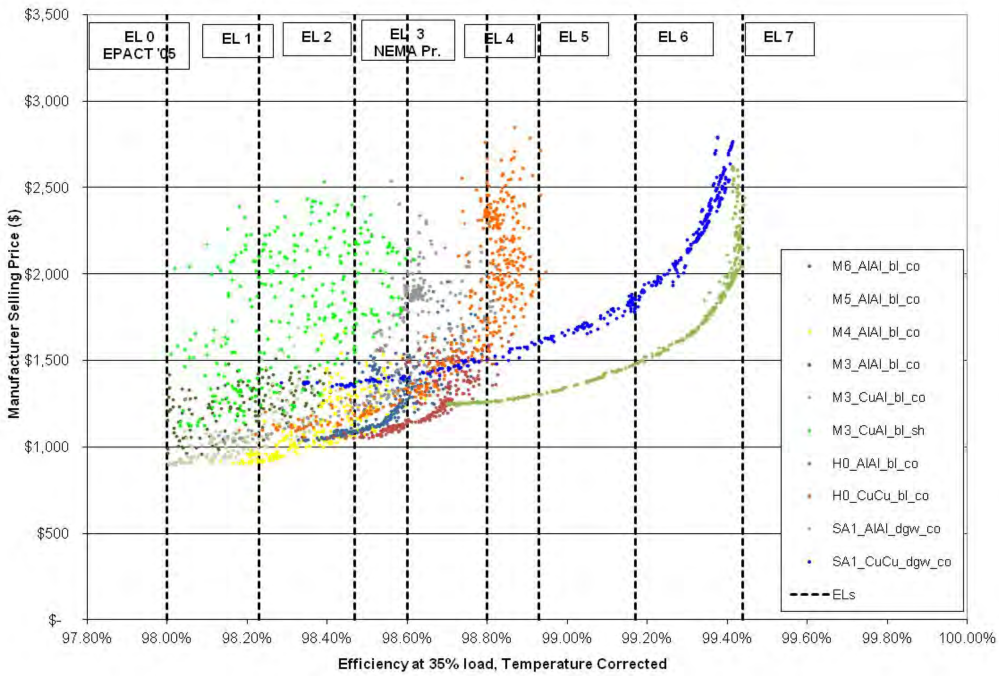

Figure 5C.11 Price and Efficiency for 2008 Material Sensitivity, Design Line 6

Figure 5C.12 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 6 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature.

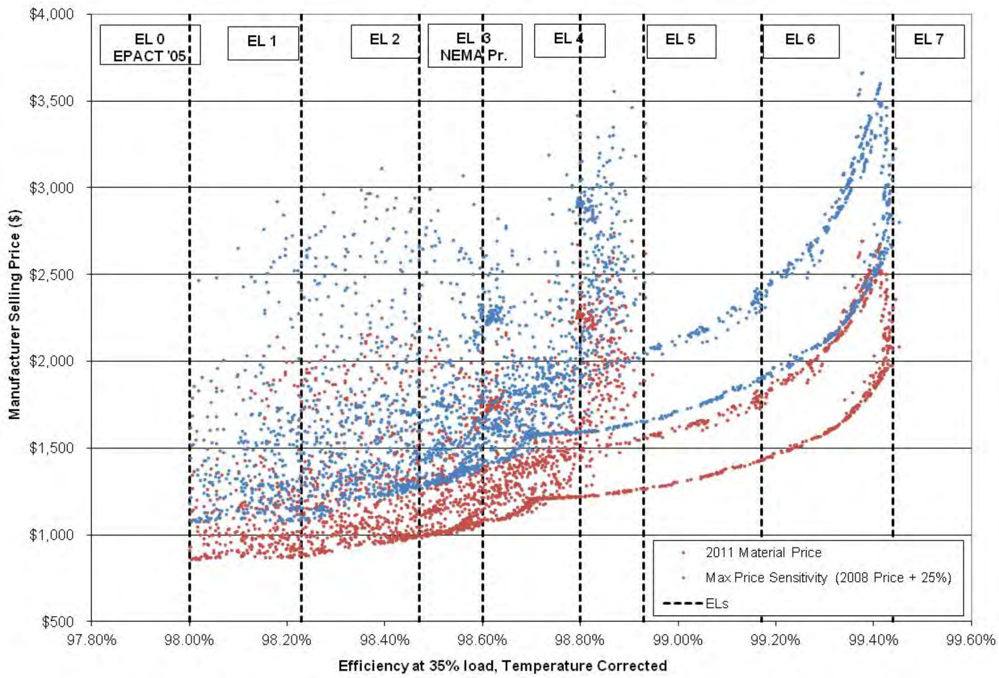

Figure 5C.12 Material Price Scenario Comparison Plot, Design Line 6

5C.2.7 Design Line 7 Engineering Analysis Results

Figure 5C.13 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 7. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature.

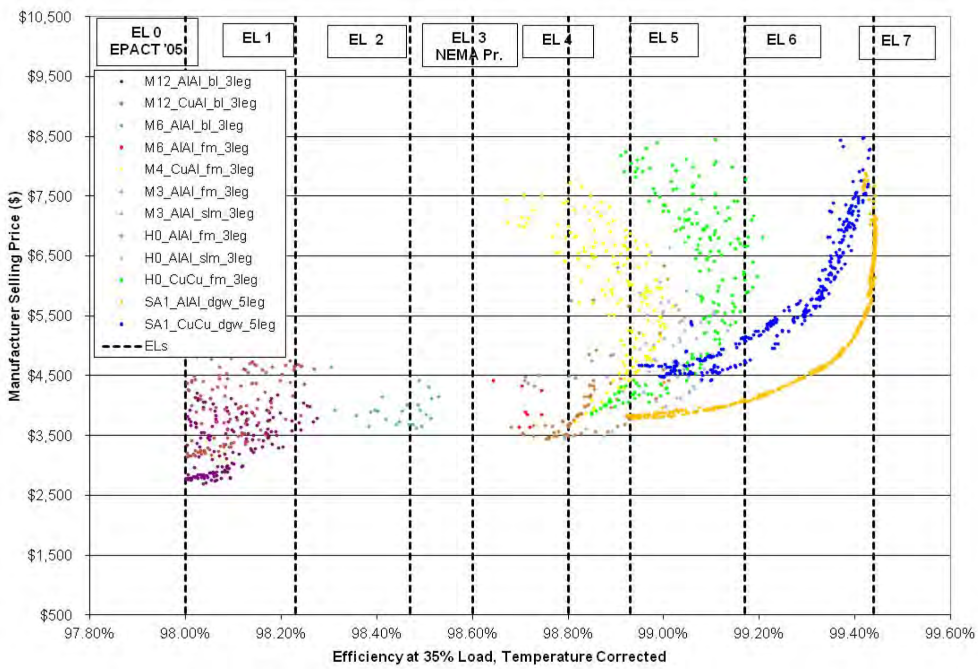

Figure 5C.13 Price and Efficiency for 2008 Material Sensitivity, Design Line 7

Figure 5C.14 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 7 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature.

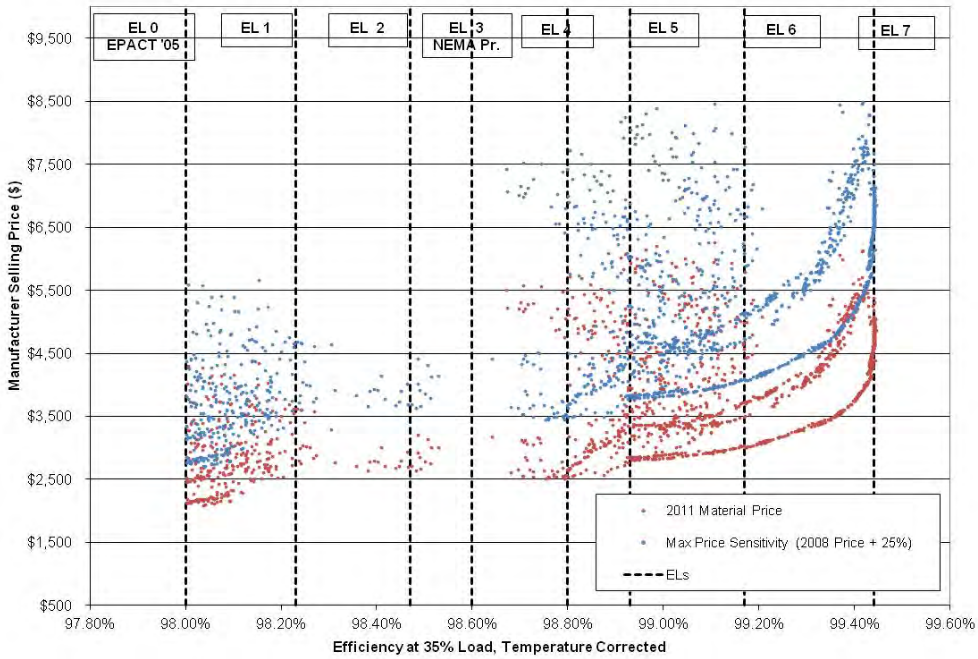

Figure 5C.14 Material Price Scenario Comparison Plot, Design Line 7

5C.2.8 Design Line 8 Engineering Analysis Results

Figure 5C.15 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 8. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature.

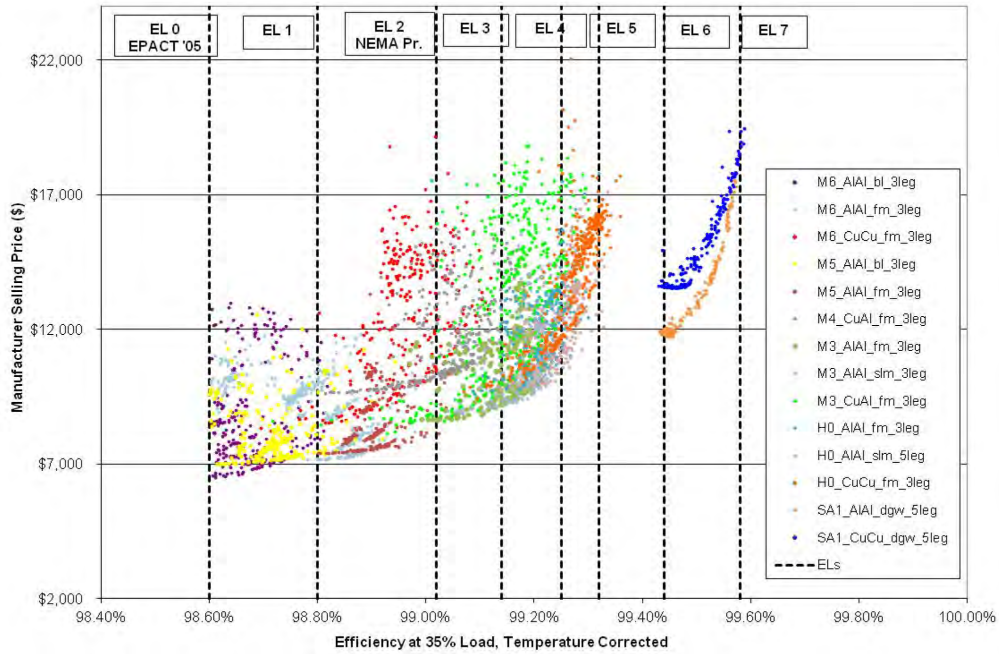

Figure 5C.15 Price and Efficiency for 2008 Material Sensitivity, Design Line 8

Figure 5C.16 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 8 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 35 percent of nameplate load and are corrected for temperature.

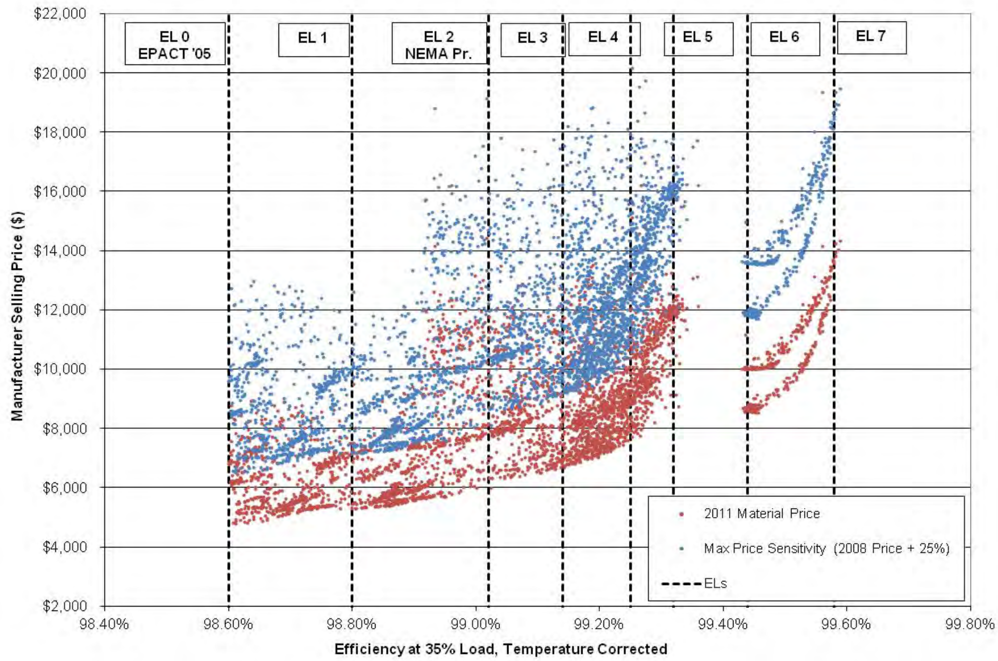

Figure 5C.16 Material Price Scenario Comparison Plot, Design Line 8

5C.2.9 Design Line 9 Engineering Analysis Results

Figure 5C.17 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 9. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

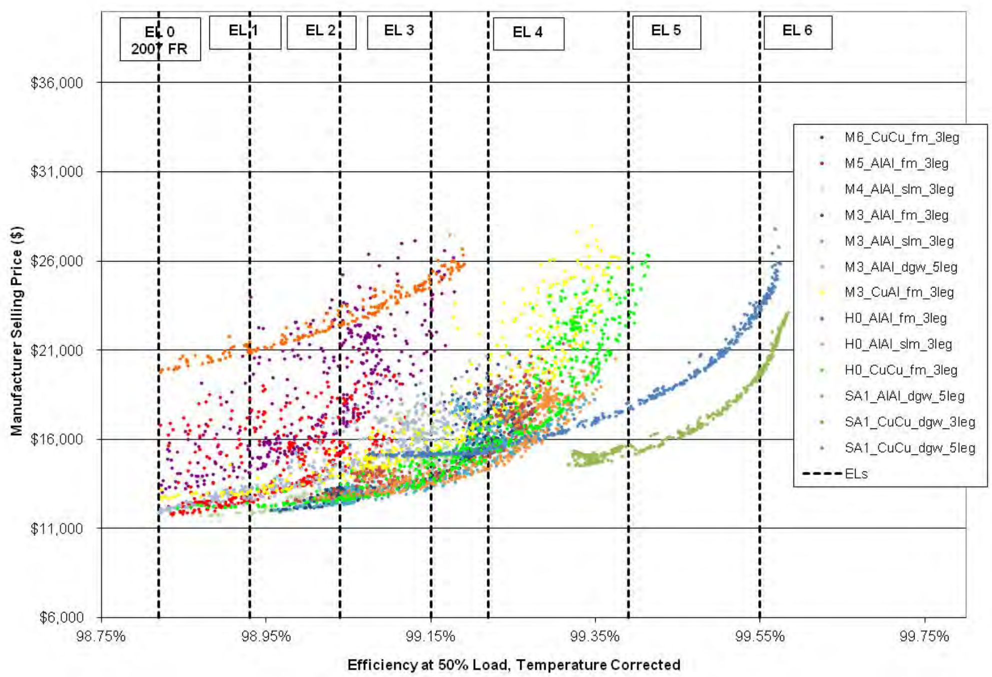

Figure 5C.17 Price and Efficiency for 2008 Material Sensitivity, Design Line 9

Figure 5C.18 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 9 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

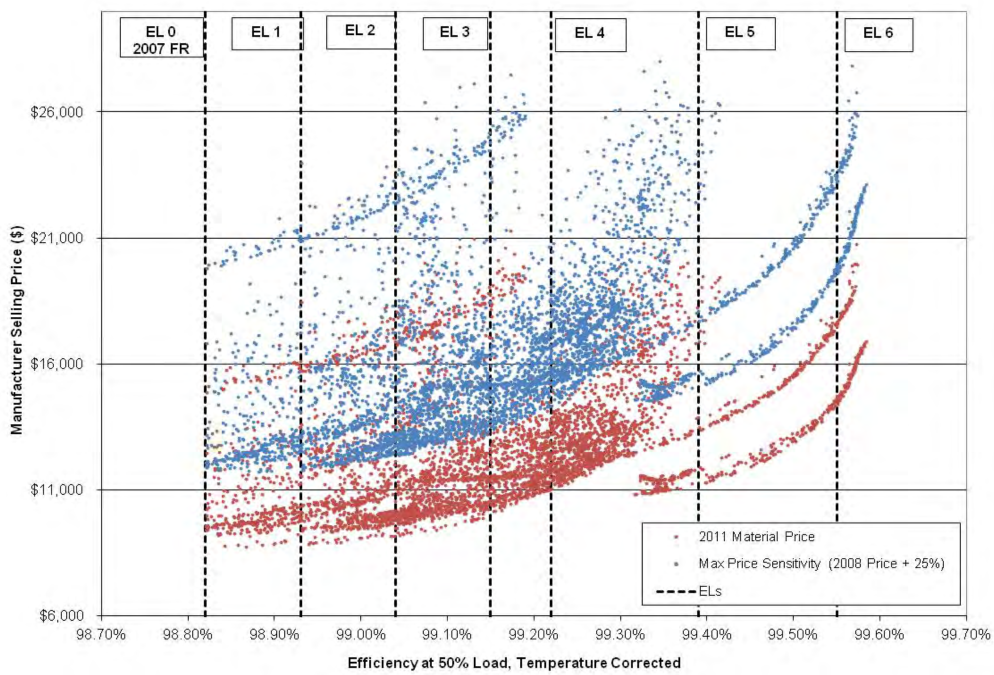

Figure 5C.18 Material Price Scenario Comparison Plot, Design Line 9

5C.2.10 Design Line 10 Engineering Analysis Results

Figure 5C.19 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 10. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

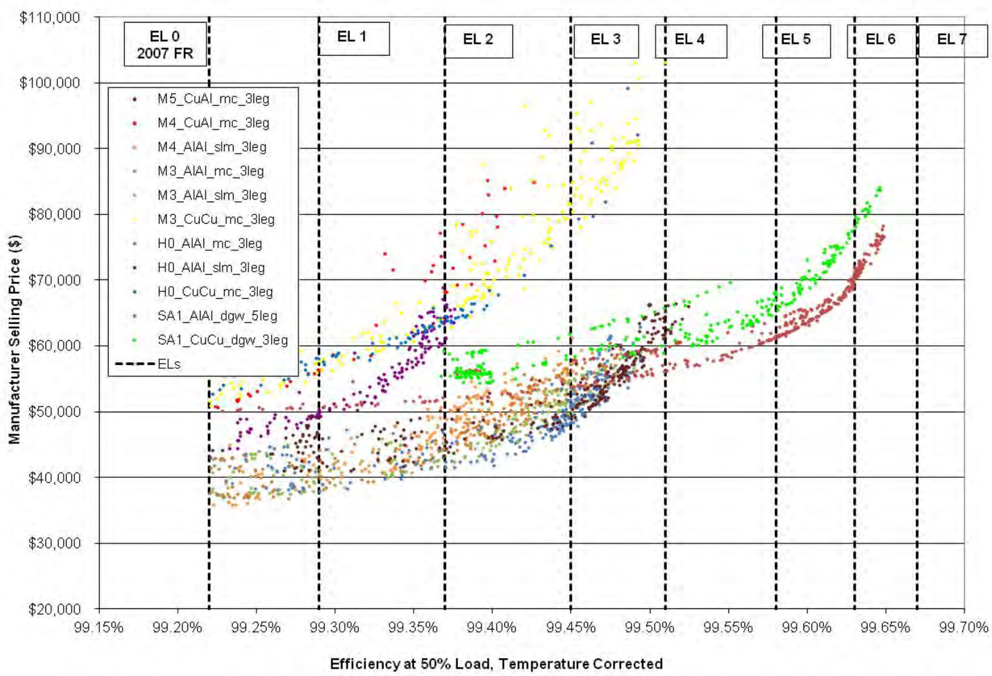

Figure 5C.19 Price and Efficiency for 2008 Material Sensitivity, Design Line 10

Figure 5C.20 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 10 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

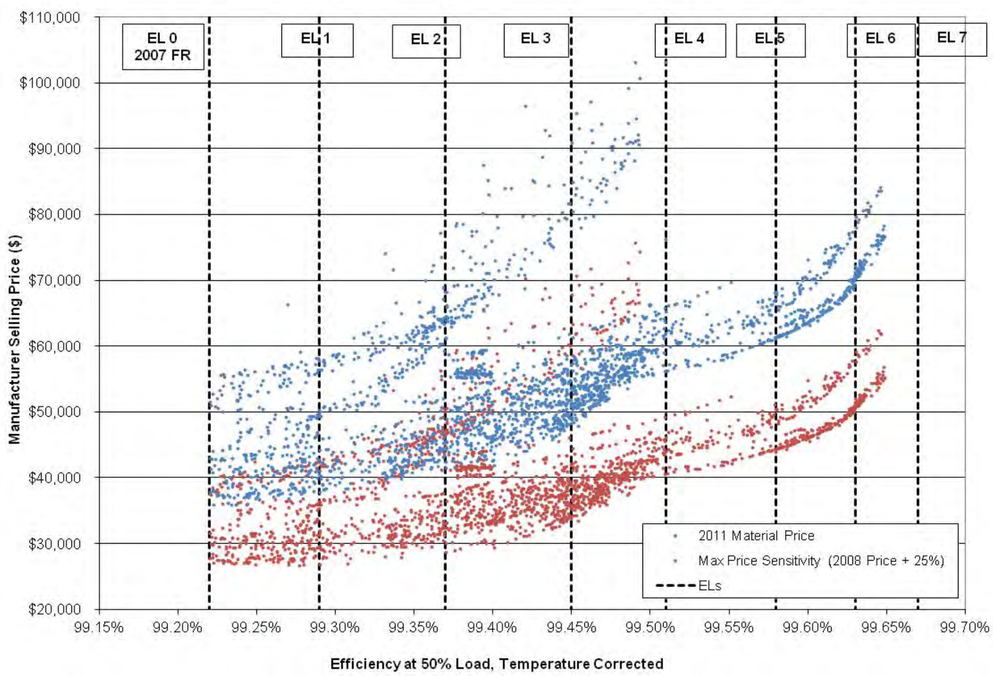

Figure 5C.20 Material Price Scenario Comparison Plot, Design Line 10

5C.2.11 Design Line 11 Engineering Analysis Results

Figure 5C.21 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 11. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

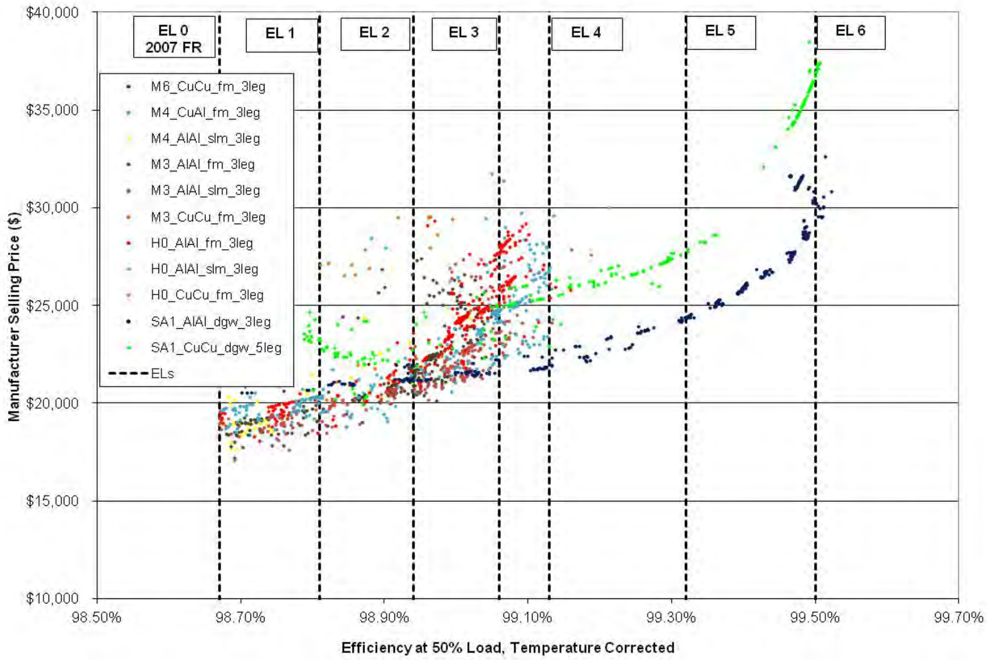

Figure 5C.21 Price and Efficiency for 2008 Material Sensitivity, Design Line 11

Figure 5C.22 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 11 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

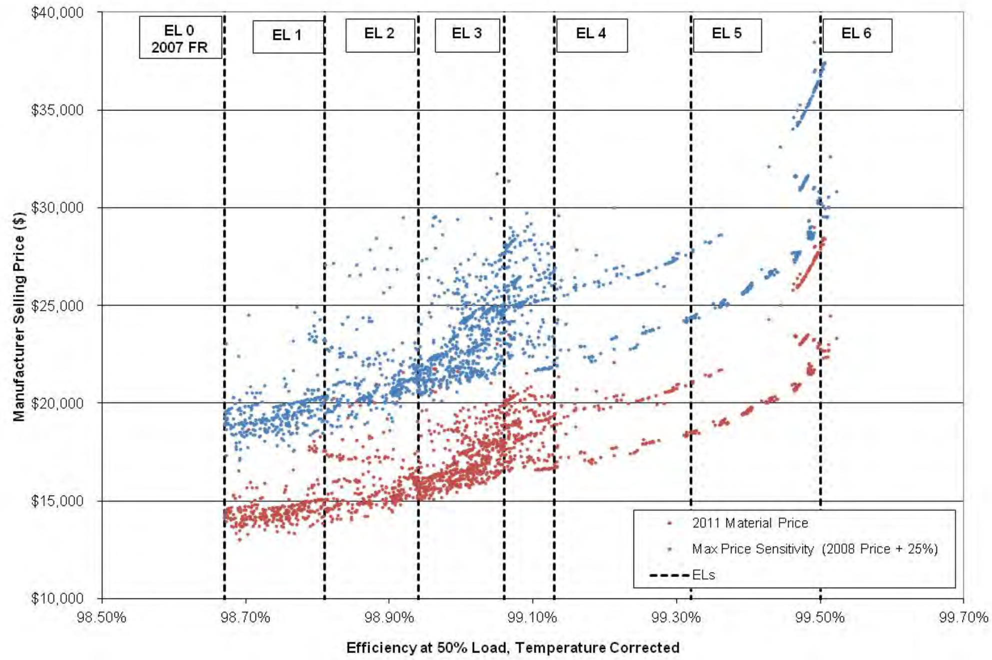

Figure 5C.22 Material Price Scenario Comparison Plot, Design Line 11

5C.2.12 Design Line 12 Engineering Analysis Results

Figure 5C.23 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 12. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

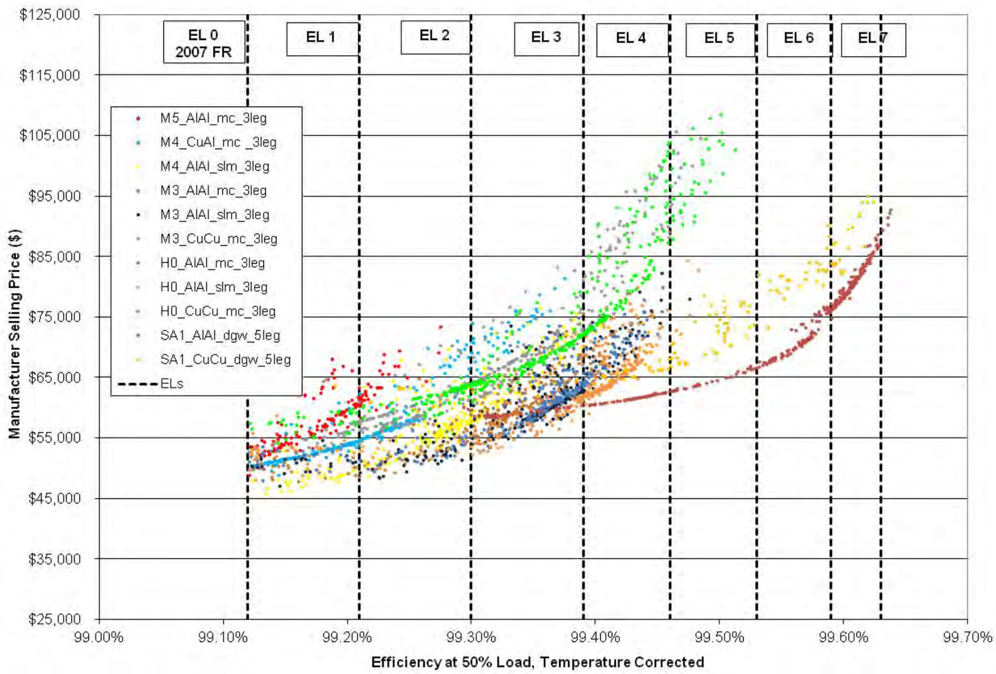

Figure 5C.23 Price and Efficiency for 2008 Material Price Sensitivity, Design Line 12

Figure 5C.24 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 12 using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

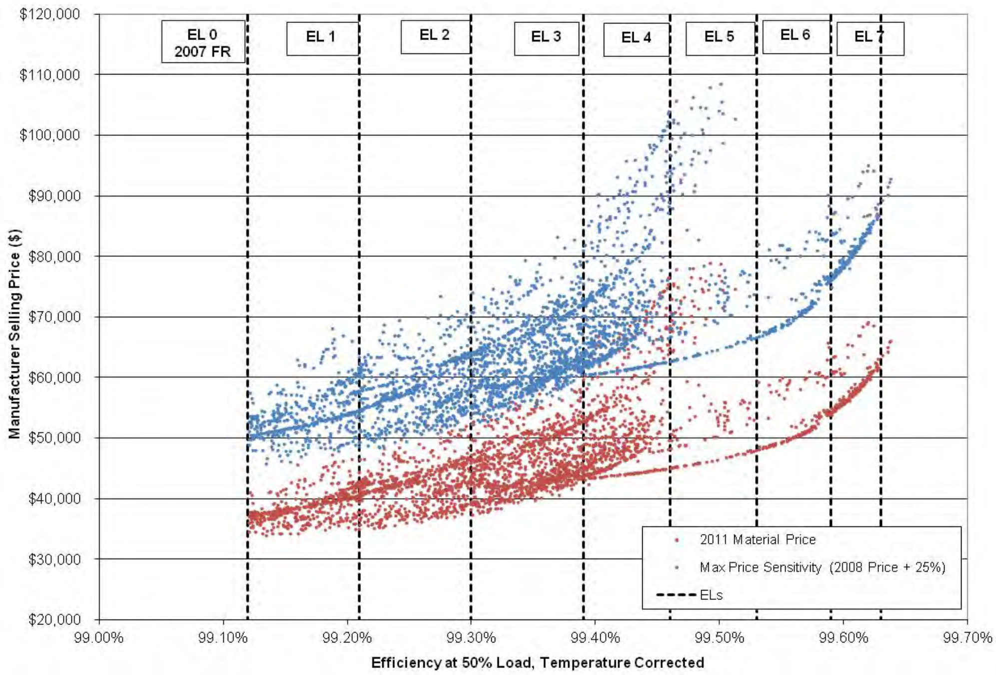

Figure 5C.24 Material Price Scenario Comparison Plot, Design Line 12

5C.2.13 Design Line 13A Engineering Analysis Results

Figure 5C.25 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 13. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

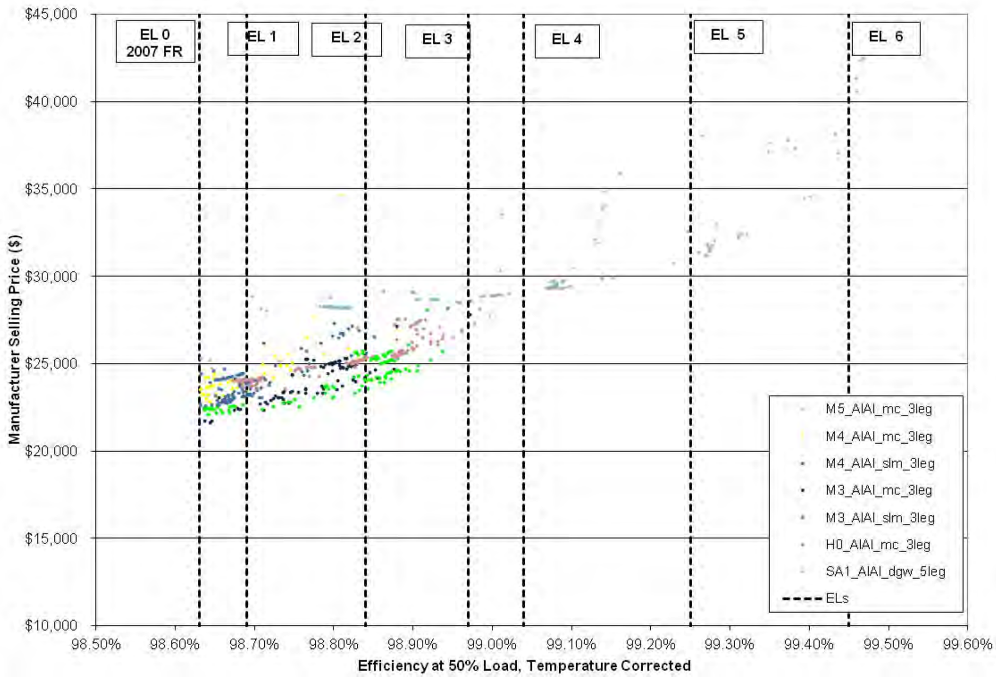

Figure 5C.25 Price and Efficiency for 2008 Material Sensitivity, Design Line 13A

Figure 5C.26 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 13A using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

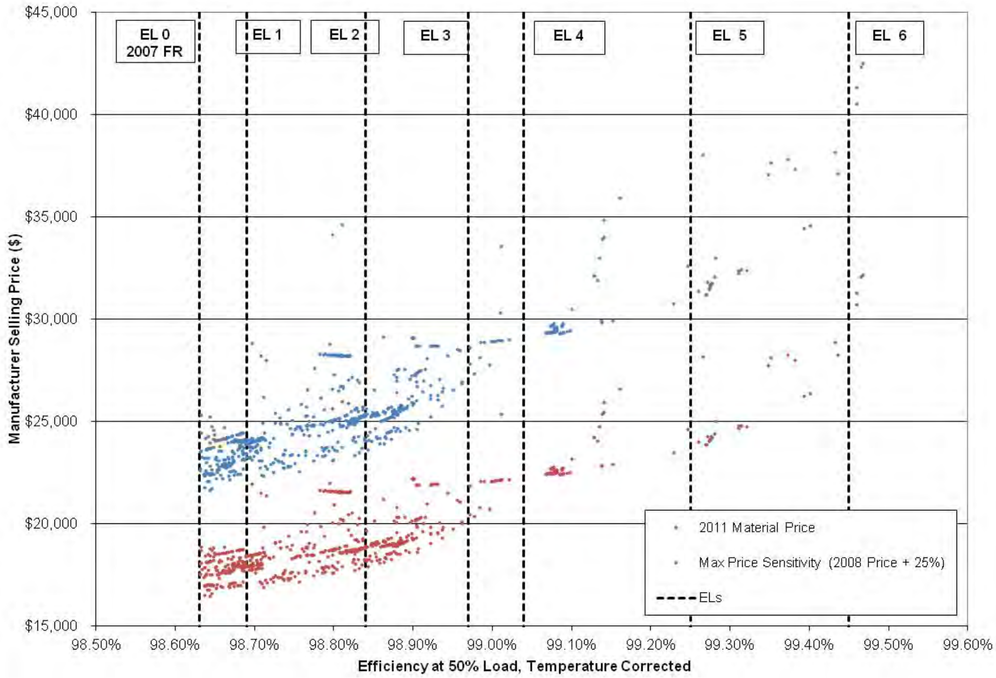

Figure 5C.26 Material Price Scenario Comparison Plot, Design Line 13A

5C.2.14 Design Line 13B Engineering Analysis Results

Figure 5C.27 presents a plot of the 2008 manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 13B. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

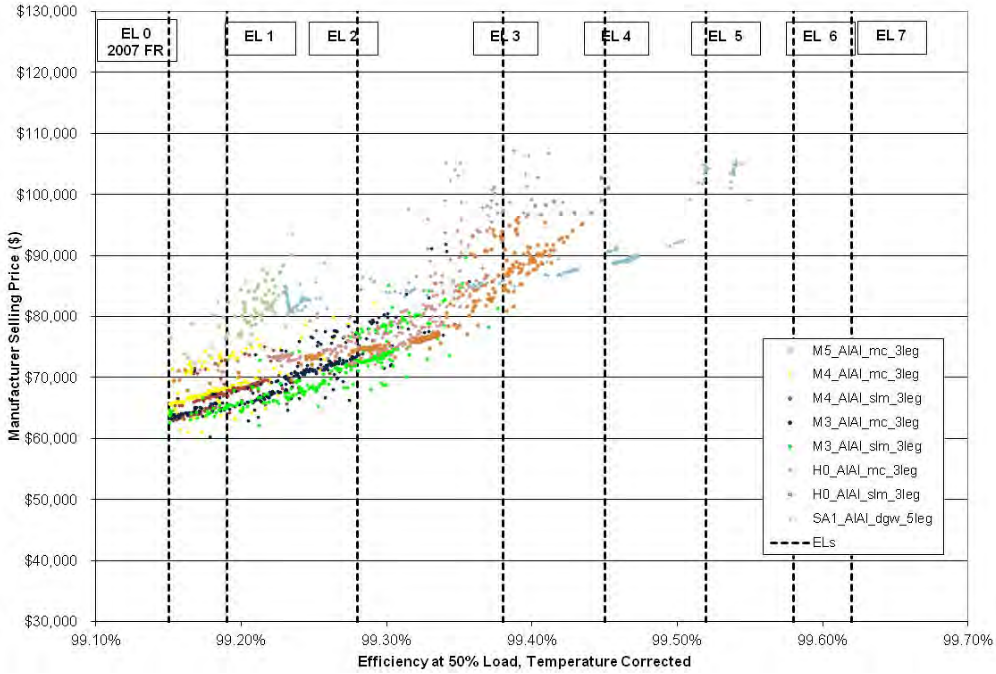

Figure 5C.27 Price and Efficiency for 2008 Material Sensitivity, Design Line 13B

Figure 5C.26 presents a plot of the manufacturer selling prices and efficiency levels for the full database of designs for the representative unit from design line 13B using both 2011 material prices and 2008 material prices. The efficiency levels shown in this plot represent transformers at 50 percent of nameplate load and are corrected for temperature.

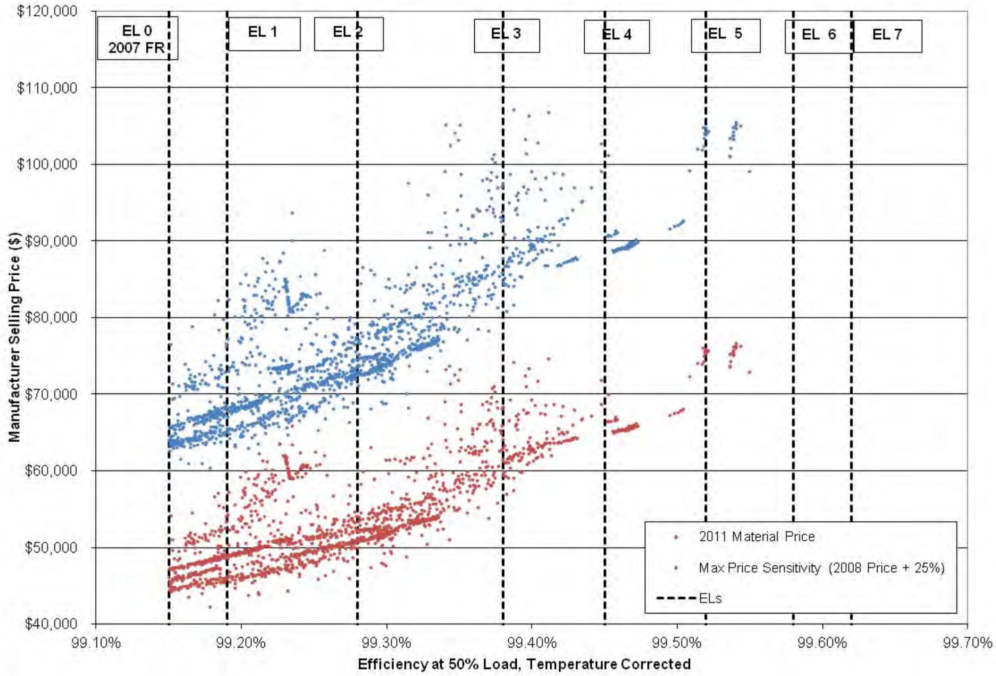

Figure 5C.28 Material Price Scenario Comparison Plot, Design Line 13B

APPENDIX 7A. TECHNICAL ASPECTS OF THE ENERGY USE AND END-USE LOAD CHARACTERIZATION ANALYSIS

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7A.1 LOADING ANALYSIS FOR LIQUID-IMMERSED TRANSFORMERS

This section provides technical details regarding the methodologies the U.S. Department of Energy (DOE) used to estimate the energy savings and coincident peak demand reductions associated with higher efficiency for liquid-immersed transformers. These types of transformers are owned primarily by utility companies. From the utility perspective, the economic value of transformer energy losses is determined by (1) the marginal price for electricity and (2) the utility's avoided capacity costs. The marginal price for electricity is both time-dependent and a property of the system or control area to which the utility belongs. For this analysis, we assign each utility to a geographic region, for which we calculate a price that varies hourly. The regions used here are the set of Electricity Market Module (EMM) regions used in the Energy Information Administration's National Energy Modeling System.[1] Regarding a utility's capacity costs, the type of generation capacity avoided depends on the shape of the load duration curve for the losses, while the amount of capacity avoided depends on the value of the transformer load when the system load is at its peak. Hence, correct estimation of the value of transformer efficiency requires an understanding of the load shape of the energy losses.

7A.2 ENERGY LOSSES

Transformer energy losses are the sum of two terms: the no-load losses (NLL), which are approximately constant in time and occur whenever the transformer is energized, and the load losses (LL), which are proportional to the square of the instantaneous load on the transformer. Including losses, the total energy used by a transformer experiencing instantaneous load E is:

$$\boldsymbol{E_T} = \in_{\boldsymbol{NLL}} + \boldsymbol{E} + \in_{\boldsymbol{LL}} \left(\boldsymbol{E}/\boldsymbol{E_{max}} \right)^{\boldsymbol{2}}. \quad \textbf{Eq. 7A.2.1}$$

Here $\in_{NLL}$ is a parameter that represents the constant (or no-load) loss rate, and $\in_{LL}$ is a parameter that expresses the load-loss rate. Because $\in_{LL}$ is defined assuming that the transformer is fully loaded, actual losses depend on the size of the scaled load E/E_{max}, where E_{max} is the expected peak load on the transformer, here assumed to be equal to its capacity. The transformer losses are E_T-E, and the transformer efficiency rating is defined as E/E_T.

For this analysis we assume that each transformer is part of a local system for which either a market-clearing price or system lambda is defined. The hourly price is denoted $p(h)$. The annual energy cost associated with transformer energy losses is the sum of two terms:

$$\boldsymbol{EC} = \boldsymbol{EC_{LL}} + \boldsymbol{EC_{NLL}} \quad \textbf{Eq. 7A.2.2}$$

where EC_{NLL} is due to the no-load losses and EC_{LL} to the load losses. Because the no-load losses are flat,

$$\boldsymbol{EC_{NLL}} = \in_{\boldsymbol{NLL}} < p > 8{,}760, \qquad \textbf{Eq. 7A.2.3}$$

where <p> is the average over all hours of the hourly marginal production cost. For the load losses,

$$\boldsymbol{EC_{LL}} = \in_{\boldsymbol{LL}} \sum_{\boldsymbol{h}} \boldsymbol{p}(\boldsymbol{h})\, \boldsymbol{e}^{\boldsymbol{2}}(\boldsymbol{h}). \qquad \textbf{Eq. 7A.2.4}$$

Here we use the variable $e(h) = E(h)/E_{max}$ to represent the hourly scaled transformer load. This term depends on the correlation between the transformer's hourly load and the system hourly price. Because we expect individual transformer loads to be correlated with the system load, it follows that they also will be correlated with the system price. Failure to correctly represent this correlation will result in underestimating the value of the load losses.

The sum over hours in equation Eq. 7-A.2.4 can be converted to a sum over load levels as follows: Let $L(h)$ be the hourly system load, and $l(h)$ the hourly scaled system load (the hourly system load divided by the annual system load maximum). Both the transformer loads and the system loads can be represented as a set of discrete load levels l_j and e_k, with $j = 1, \dots N_S$ and $k = 1, \dots N_T$. This means that in each hour we replace the actual load value with the closest discrete value. This procedure does not introduce a bias and will not lead to a significant loss of precision. The shape of the system load can be characterized by a distribution function n_j, where n_j is the number of times the system load is at level l_j. It is also reasonable to assume that the system price P can be represented as a function f of the system load:

$$\boldsymbol{p}(\boldsymbol{h}) = \boldsymbol{f}(\boldsymbol{l}(\boldsymbol{h})). \qquad \textbf{Eq. 7A.2.5}$$

This function is equivalent to assuming that variation in the system price is driven by variation in the system load. Given the function f and the load level l_j, a price is defined as $p_j = f(l_j)$. The last required term is a function that represents the correlation between the transformer load levels e_k and the system load levels l_j. Let w_{jk} be the probability that the transformer load is at level e_k when the system load is at level l_j. Combining the terms defined above, the hourly sum becomes:

$$\sum_{\boldsymbol{h}} \boldsymbol{p}(\boldsymbol{h})\, \boldsymbol{e}^{\boldsymbol{2}}(\boldsymbol{h}) \;=\; \sum_{\boldsymbol{j}} \sum_{\boldsymbol{k}} \boldsymbol{n_j p_j w_{jk} e_k^2}. \qquad \textbf{Eq. 7A.2.6}$$

7A.2.1 Price-Load Function

This section describes how DOE developed a function that expresses the system price as a function of system load. For each EMM region, we calculated hourly time series for system loads and system prices based on 2008 hourly load and price data for individual utilities and control areas, obtained from Federal Energy Regulatory Commission (FERC) Form 714 filings. Then we calculated the system load distribution function n_j by defining a set of bins to contain the load levels, and counting the number of times the system load falls into each bin. The system price function is estimated assuming:

$$\boldsymbol{p_j = \bar{p}_j + \delta_j}, \qquad \textbf{Eq. 7A.2.7}$$

where $\bar{p}_j$ is a constant term and δ_j is a random increment that may be positive or negative.

The calculation steps are described in more detail below.

1. Each load and price time series obtained from FERC is assigned to an EMM region, based either on the appropriate North American Electric Reliability Corporation (NERC) region or the set of states in which the utility operates. Table 7-A.2.1 lists the EMM regions, the NERC regions they belong to.
2. The load time series for an EMM region is defined as the sum of the load data for each of the utilities or control areas in that region.
3. The price time series is defined as the average load-weighted sum of the price data for each utility or control area in the region.
4. The minimum and maximum system loads are calculated, followed by the scaled system load $l(h) = L(h)/L_{max}$. The values of l satisfy $L_{min}/L_{max} \leq l \leq 1$.
5. The number of bins N_S, bin sizes Δ_j, and bin boundaries l_j are defined. The bin widths may vary with j. Widths are chosen to satisfy two criteria: (1) that the number of points in each bin is of the same order of magnitude, and (2) that the range of variation in price within each bin is not too large.
6. The number of hourly values $l(h)$ that fall into each bin is counted; this number is defined as n_j, with $\sum_j n_j = 8{,}760$.
7. The average value of $l(h)$ in each bin is calculated; this value is written as $\bar{l}_j$.
8. The average value of the price during the hours in which the load is in bin j, ($\bar{p}_j$), is calculated.

Table 7A.2.1 Definition of EMM regions and NERC regions in terms of States

EMM Region	NERC Region
NE	NPCC
NY	NPCC
SPP	SPP
ERCOT	TRE
FL	FRCC
RA	WECC
RA	WECC
NPP	WECC
CA	WECC
ECAR	RFC
MAAC	RFC
MAIN	RFC
MAIN	MRO
MAPP	MRO
MAIN	SERC
ECAR	SERC
SERC	SERC

The price load-relationship, and the way the data are sorted into bins, is illustrated in Figure 7-A.2.1.

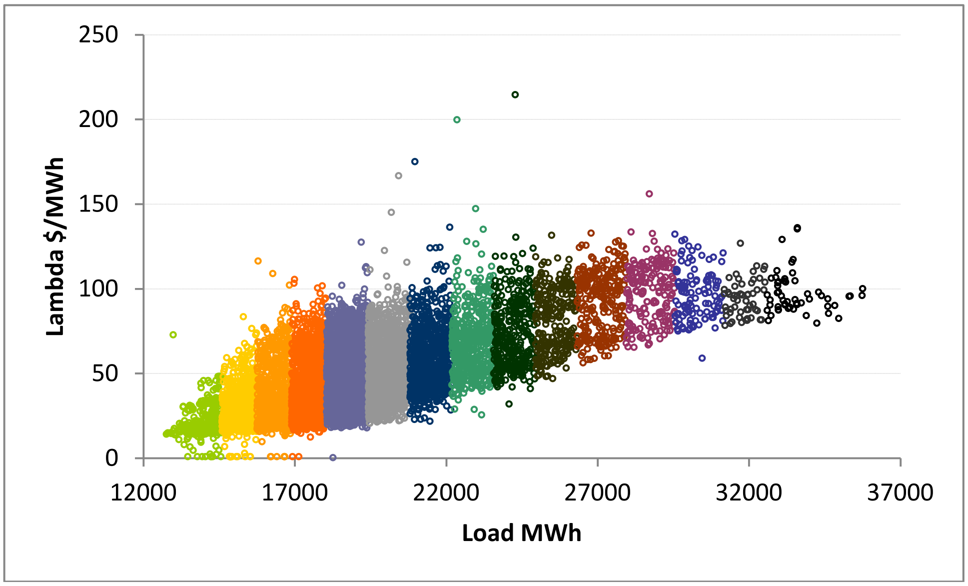

Figure 7A.2.1 System Load and Price for the SPP Region. Fifteen Load Bins are Defined in the Figure, Indicated by the Different Colors

Figure 7-A.2.1 shows a scatter plot of hourly prices (on the vertical axis) and loads (on the horizontal axis) for the SPP region. The load data, and corresponding price values, have been distributed into a set of fifteen bins, which are given different colors in the figure. The plot shows that there is a large range of price variability within each bin, and that the range also varies with the bin index. In this region the price variability is lowest in the low and high bins, and highest near the center. Other regions may differ in the details of this relationship. To capture this effect, the price model includes a random increment δ_j, which may be positive or negative, and which is chosen from an empirically determined probability distribution function (PDF). Each region and bin has its own parameters for the PDF. The data used to define this PDF are the differences $z = P(h) - \bar{p}_j$; there is one z for each hourly price $P(h)$ in bin j. For simplicity, the PDF is assumed to be triangular and centered at zero. Mathematically, the distribution is defined by three parameters: a_j, b_j, and c_j, where:

$-a_j$ = is the point at which the triangular distribution intersects the negative z-axis,
b_j = is the point at which the triangular distribution intersects the positive z-axis, and
c_j = is the value of the probability distribution function at z = 0.

By definition, the area under the distribution is equal to one, which leads to the following expression for c_j:

$$\boldsymbol{c_j = {}^{2}\!/\!(b_j + a_j)}. \qquad \textbf{Eq. 7A.2.8}$$

There generally are various possible ways to map data onto a triangular distribution. Here, the primary concern is to include the effect of variability without introducing any price bias into the model. To this end, the parameters a_j and b_j are defined so that the average positive (or negative) value of the difference $z = P(h) - \bar{p}_j$ is the same for the triangular model distribution as it is for the real distribution. These constraints can be written:

$$\boldsymbol{S_j^- = {}^{c_j a_j}\!/_{6}\,;\;\; S_j^+ = {}^{c_j a_j}\!/_{6}}, \qquad \textbf{Eq. 7A.2.9}$$

where S_j^- is the sum of all negative differences z in bin j, and S_j^+ is the sum of all positive differences. These equations allow us to determine a_j, b_j, and c_j from the data. The model is validated by using the PDF to generate a series of δ-values for each bin, then comparing the standard deviation of the δ's for the original data and for the simulated data. For each region and each bin, the standard deviations for the model data typically are within about 10 percent (higher or lower) of the standard deviation values calculated for the original data.

7A.2.2 Joint Distribution of System and Transformer Loads

In this section we describe how DOE calculated the joint probability distribution function (JPDF) of transformer loads and system loads. The data set available at the time of this analysis was a set of hourly building loads indexed by x, $e_x(h)$, x=1,...M. Each hourly load is scaled by its annual maximum, so that they all range in magnitude between zero and one. We assume that the loads on individual transformers are similar in shape to the loads on buildings. The relationship expressed by the function w_{jk} is the correlation between an individual load and the total load of the system of which the individual load is a part. To estimate this relationship from the available data, we defined a (scaled) proxy system load $pl(h)$ as the sum of the individual building loads:

$$\boldsymbol{pl(h)} = \left({}^{\boldsymbol{1}}/_{\boldsymbol{M}}\right) \sum_{x} \boldsymbol{e_x(h)} \qquad \textbf{Eq. 7A.2.10}$$

The function w_{jk} is estimated by distributing the hourly load pairs $\left(e_x(h), pl(h)\right)$ into a set of N_T by N_S bins and counting the number of points in each bin. The modeling steps are described in more detail below.

1. Construct the set of scaled data pairs $\left(pl(h), e_x(h)\right), h = 1,2 \ldots, 8760.$
2. Define the bins for the proxy load *pl*; these are identical to the bins used in the system load analysis described in section 7-A.2.1 above. There are N_S bins having index *j*.
3. Define the bins for the individual transformer loads; here the number of bins is N_T, the bin index is *k*, and the bin width is constant and equal to $1/N_T$.
4. Count the number of points (*j*, *k*) in each bin; this count is defined as m_{jk}^x.
5. Calculate the average of the m_{jk}^x for all the transformer load time series and divide by 8,760 to convert this count to a probability:

$$\boldsymbol{w_{jk}} = (\boldsymbol{1/8760})(\boldsymbol{1/M}) \sum_{x} \boldsymbol{m_{jk}^x}. \qquad \textbf{Eq. 7A.2.11}$$

The number w_{jk} is an estimate of the probability of finding a transformer load in bin *k*, given a system load in bin *j*. The value of the transformer load in bin *k* is estimated as the average value for all points in the bin, irrespective of the value of *j*.

The building data set available for this analysis included residential, commercial and industrial buildings for three data years. Because the correlation patterns may depend on building type, separate JPDFs were calculated for residential, commercial and industrial buildings. The proxy system load is always defined as the sum of residential, commercial, and industrial building loads. To make use of multiple years of building data, we estimated w_{jk} separately for each data year, then averaged the results. An example of the output is shown in Figure 7-A.2.2. The plot shows the JPDF calculated for the commercial building data. In this plot, lower bin indices correspond to lower load levels. The plot shows the expected feature that transformer loads in commercial installations are correlated loosely with system load when system loads are low, and are correlated more tightly when system loads are high. The industrial and residential JPDF, shown in figure 7-A.2.3 and figure 7-A.2.3, shows that transformers in residential and industrial installations generally are not strongly correlated with system loads.

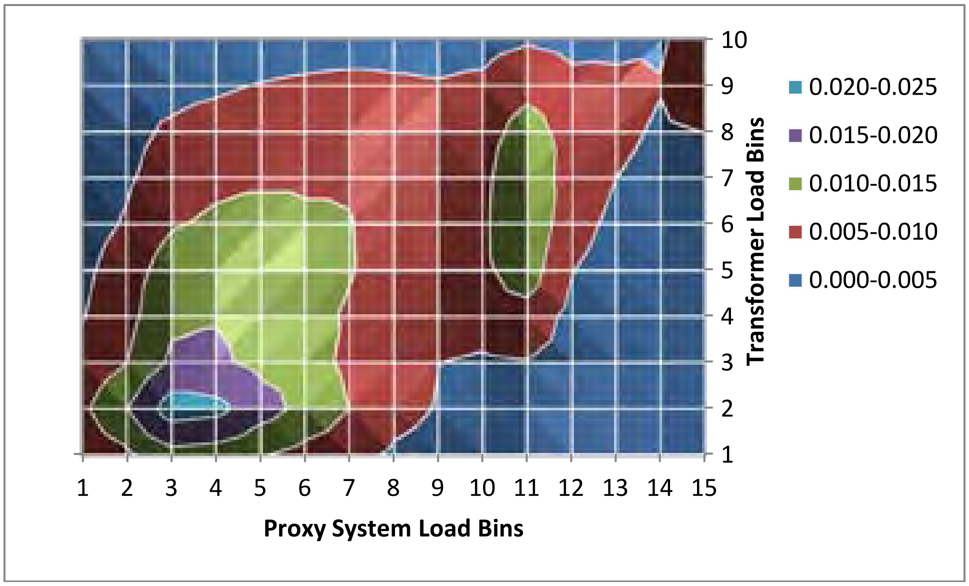

Figure 7A.2.2 Joint Probability Distribution Function for Commercial Load Data; the Function is an Average of Three Functions Calculated Separately for 1998, 1999, and 2000

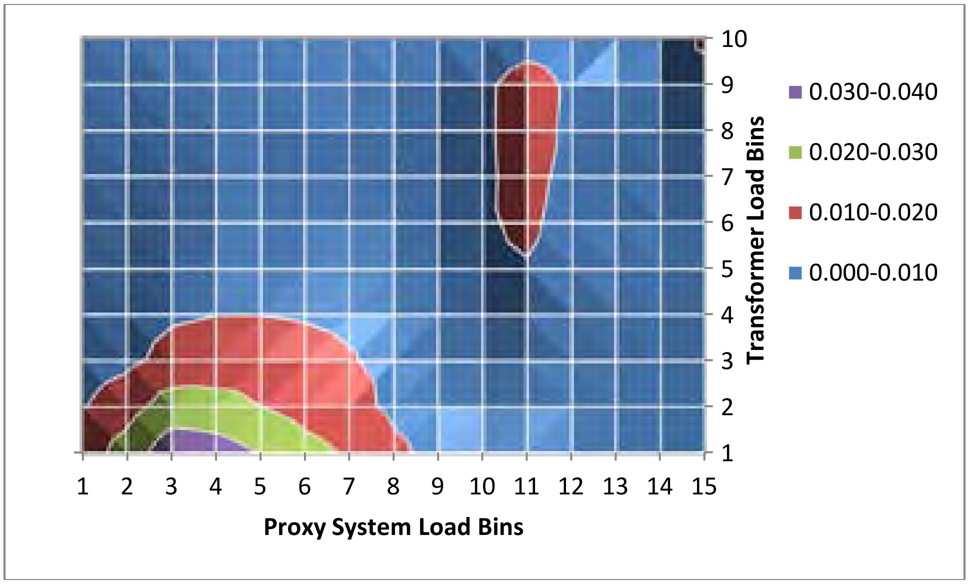

Figure 7A.2.3 **Joint Probability Distribution Function for Industrial Load Data; the Function is an Average of Three Functions Calculated Separately for 1998, 1999, and 2000**

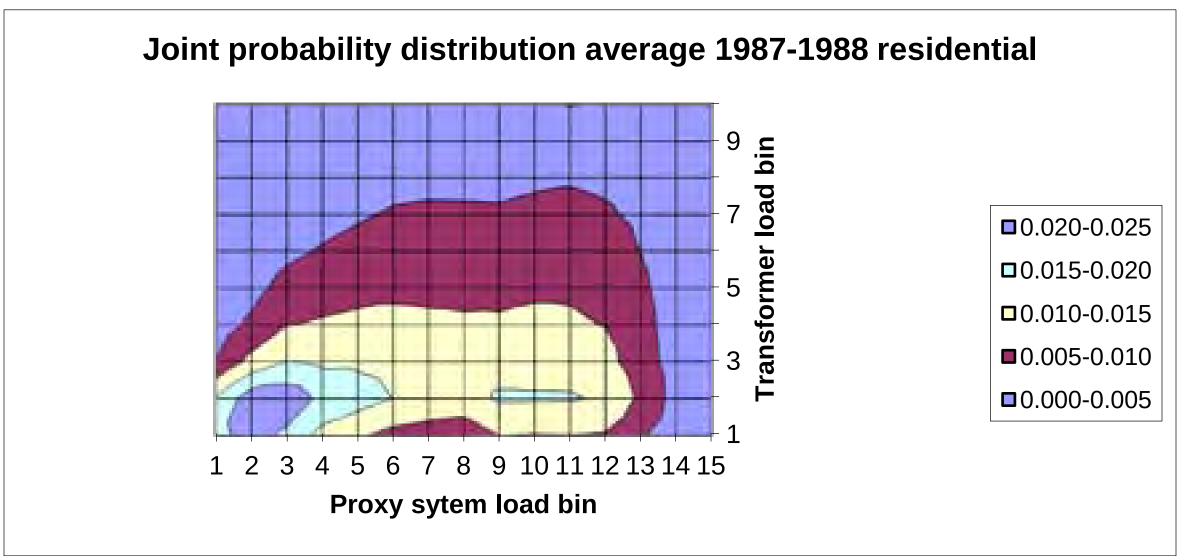

Figure 7A.2.4 **Joint Probability Distribution Function for Residential Load Data; the Function is an Average of Three Functions Calculated Separately for 1998, 1999, and 2000**

There are insufficient data to validate the JPDF directly. We examined the robustness of the JPDFs by calculating test JPDFs using subsets of the full set of available hourly loads. The total number of buildings in a single sample varies with year and with building type, from about 50 to about 300. The difference between the JPDF calculated using a fraction of the full data set and a JPDF calculated using all buildings was quantified using the L1 norm.[a] The tests showed that the JPDF is insensitive to the subset of buildings chosen as long as there are about 100 buildings or more in the data set. The JPDFs calculated with different subsets of 100 or more buildings do not vary significantly.

7A.2.3 Transformer Peak Responsibility Factor

Reductions in transformer losses can reduce the system peak load, and hence avoid capacity costs. The size of the reduction in system peak load depends on the size of the transformer load loss during the hour of the system peak. This value is known as the transformer peak responsibility factor. A probability distribution for the responsibility factor can be estimated easily from the JPDF w_{jk}. We define the probability r_k that the transformer load level is e_k when the system load is at a peak as:

$$\boldsymbol{r_k = {w_{N_S,k}} \Big/ {\sum_k \left(w_{N_S,k}\right)}}. \qquad \textbf{Eq. 7A.2.12}$$

Strictly speaking, r_k gives the probability that the transformer load is in bin k when the system load is in its highest bin (j=N_S). When averaged over the lifetime of the transformer, this value should give a reasonably estimate of the distribution of the responsibility factor.

7A.3 LOADING ANALYSIS FOR DRY-TYPE TRANSFORMERS

This appendix provides technical details regarding the methodologies the U.S. Department of Energy (DOE) used to estimate the energy use and peak demand for dry-type transformers. This type of equipment is used primarily in commercial buildings and is owned by the building owner or operator. The economic value of energy losses therefore is determined by the marginal price of electricity for the building, which is set by the prevailing electricity tariff. In this analysis, the Department draws on a previous, detailed study of energy prices for commercial buildings.[2] That study showed that each building's electricity costs can be represented as a marginal price for energy (MPE) and a marginal price for demand (MPD), which vary by region and by season. In an economic analysis, these prices are used as follows:

$$\Delta B = (\Delta E_{LL} + \Delta E_{NLL}) * MPE + (\Delta D_{LL} + \Delta D_{NLL}) * MPD \qquad \textbf{Eq. 7A.3.1}$$

Where:

ΔB = the total change in the electricity bill for the transformer owner;

MPE = the marginal price for building electricity consumption (dollars per kilowatt-hour [$/kWh]);

[a]The L1 norm is equal to the absolute value of the difference between the two functions.

MPD	=	the marginal price for building electricity demand ($/kW)
ΔE_{LL}	=	the change in electricity consumption due to load losses (kWh);
ΔE_{NLL}	=	the change in electricity consumption due to no-load losses (kWh);
ΔD_{LL}	=	the change in electricity billing demand due to load losses (kW); and
ΔD_{NLL}	=	the change in electricity billing demand due to no-load losses (kW).

The electricity billing demand is the building peak load during the billing period, which is assumed to be one calendar month. Hence, the change in demand is equal to the change in transformer losses at the time of the building peak load. The life-cycle (LCC) analysis (chapter 8 of this preliminary TSD) calculates the change in the bill for each month in a calendar year for each efficiency standard, and totals those changes to estimate the annual operating cost savings for a given transformer owner. The load profiles for both the building and the transformer vary by month, but the marginal MPE and MPD vary by season only (summer and winter). For both no-load and load losses, the change in electricity consumption and demand depend on the difference between the base-case transformer loss rates, and the standards-case loss rates. The rest of this appendix explains how those changes are calculated in the LCC spreadsheet.

7A.3.4 No-load losses

No-load losses are independent of the load on the transformer and thus have a perfectly flat load shape. The change in the transformer no-load losses is equal to the difference between the base-case transformer loss rate and the standards-case loss rates, times the number of hours per year the transformer is energized:

$$\Delta E_{NLL} = (NLL_{BaseCase} - NLL_{StandardsCase})*HPY \qquad \textbf{Eq. 7A.3.2}$$

Where:

$NLL_{BaseCase}$	=	the no-load loss rate in the base case (kW);
$NLL_{StandardsCase}$	=	the no-load loss rate in the standards case (kW); and
HPY	=	the hours per year that the transformer is energized, equal to 8,760.

Because the no-load losses are flat (constant in every hour), the change in billing demand is equal only to the change in the no-load loss rate:

$$\Delta D_{NLL} = (NLL_{BaseCase} - NLL_{StandardsCase}).$$

7A.3.5 Load Losses

This section describes the load losses for distribution transformers, used to calculate both the energy and demand savings in the LCC spreadsheet.

7A.3.5.1 Energy Savings

Load-dependent losses are proportional to the square of the load on the transformer. The change in transformer losses is equal to the change in the load loss rate times the square of the hourly load $L(h)$, summed over all hours in the year:

$$\Delta E_{LL} = (LL_{BaseCase} - LL_{StandardsCase})*[\ \textstyle\sum_h (L(h)/PL)^2\ ]*(PL/CAP)^2 \qquad \textbf{Eq. 7A.3.3}$$

Where:

$LL_{BaseCase}$	=	the load loss rate in the base case (kW),
$LL_{StandardsCase}$	=	the load loss rate in the standards case (kW),
$L(h)$	=	the hourly transformer load *h*,
PL	=	the annual peak load on the transformer, and
CAP	=	the transformer capacity.

The above equation follows the convention whereby hourly loads are expressed as a fraction of the annual transformer peak load *PL*, and the peak load is expressed relative to the transformer capacity. The annual *PL* is equal to the initial peak load times an annual growth factor, both of which parameters are inputs to the spreadsheet. Load shape information is contained in the sum of squared hourly loads. For the LCC, the sum should be calculated for each monthly billing period:

$$LSF_M = [\ \textstyle\sum_h (L(h)/PL)^2\ ]/NH$$

Where:

LSF_M	=	the monthly transformer loss factor, and
NH	=	the number of hours during the billing period that the transformer is energized, defined here as 8,760/12

A statistical model is used to estimate LSF_M as a function of the building's monthly load factor. This approach is based on the well-known "rule-of-thumb":[3]

$$LSF = \alpha*LF + (1-\alpha)*LF^2$$

Where:

α	=	alpha, a numerical parameter defined so that $0 < \alpha < 0.5$;
LSF	=	the transformer loss factor defined for a given, fixed period; and
LF	=	the load factor, equal to the average load divided by the peak load, using the same period as for the *LSF*.

The equation can be rearranged to give:

$$\alpha = (LSF - LF^2)/(LF - LF^2) \qquad \textbf{Eq. 7A.3.4}$$

A distribution of values for the parameter α is estimated using hourly building load data. First we process the data to produce monthly values of the load factor LF_M and loss factor LSF_M. For each building and each month, we use the values of LF_M and LSF_M to calculate a value of α. Finally, we calculate a frequency distribution for α from the set of monthly values. Because electricity prices are seasonal, we examined the data to evaluate whether the α-distributions varied with season, but found no significant dependence. The α-distributions do vary as a function of load factor, however. To capture this effect, we calculated three separate distributions for three ranges of load factor: low ($0 < LF_M \leq 1.3$), medium ($1/3 < LF_M \leq 2/3$), and high ($2/3 < LF_M \leq 1$). The distributions are shown in Figure 7-A.3.2.

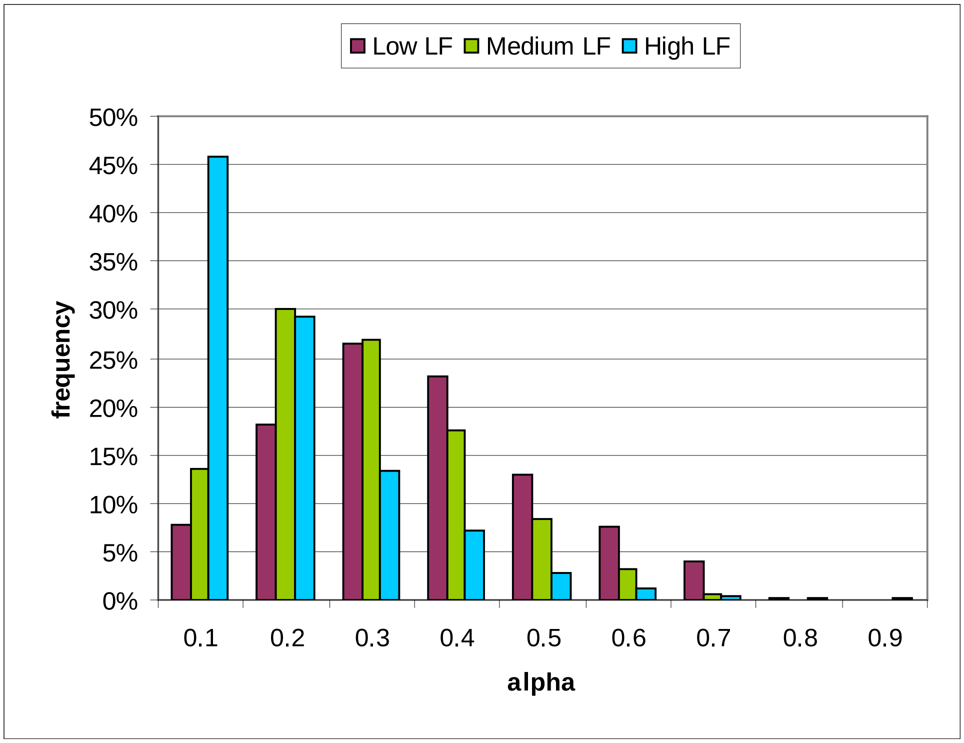

Figure 7A.3.2 Frequency Distributions for the LSF

Within the LCC, the consumer data include monthly values for the building load factor, which are used as proxies for the transformer load factor. For each month, the distributions shown in Figure 7-A.3.1 are used to select a value of α, and Eq. 5-P.1.4 is used to estimate the loss factor.

7A.3.5.2 Demand Savings

The billing demand savings associated with each possible standard are equal to the change in the transformer load loss rate times the square of the transformer load during the hour of the building peak load:

$$\Delta D_{LL} = (LL_{BaseCase} - LL_{StandardsCase})*(L(hmax)/PL)^2 *(PL/CAP)^2 \qquad \textbf{Eq. 7A.3.5}$$

Where:

hmax	=	the hour of the building peak load, and
L(hmax)	=	the transformer load during hour *hmax*.

The ratio L(hmax)/PL is defined as the coincident peak load (CPL) for the building. Using this parameter, the equation for the billing demand savings becomes:

$$\Delta D_{LL} = (LL_{BaseCase} - LL_{StandardsCase})*CPL^2 *(PL/CAP)^2 \qquad \textbf{Eq. 7A.3.6}$$

The square of the CPL is known as the peak responsibility factor (RF). The LCC calculation uses a statistical model to estimate monthly values of CPL/RF. The data available for this study included only whole building loads, not individual transformer loads. To approximate the behavior of a building containing several transformers, we manipulated the building data as follows.

1. We summed the individual hourly loads to create a single aggregate load.
2. For each month, we calculated the hour *hmax* of the peak aggregate load.
3. For each individual hourly load and each month, we calculated the value of the individual load during hour *hmax*.
4. From this procedure, we derived a set of monthly values of CPL.

The distribution of values of the coincident peak loads calculated in this way is illustrated in Figure 7-A.3.2, which shows the cumulative distribution function for CPL as well as several powers of CPL.

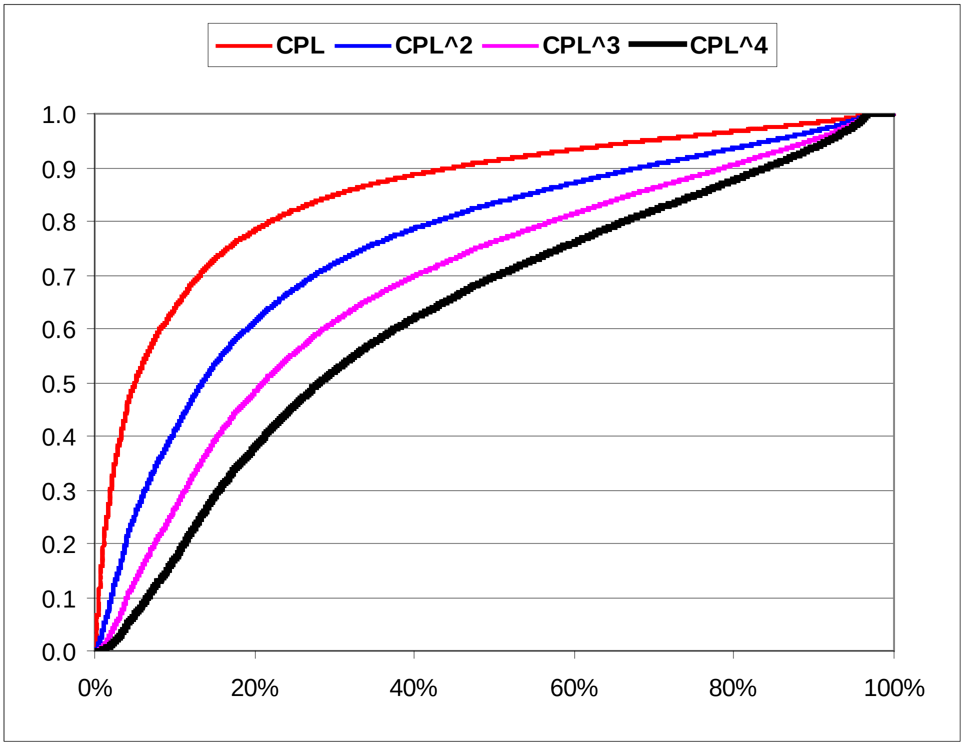

Figure 7A.3.3 Cumulative Distribution Function for the Coincident Peak Load

Roughly 80 percent of the CPL values in the sample are greater than 0.8. Examination of the data showed that the value of CPL is sensitive to season; this makes sense as space conditioning should lead to higher coincidence and therefore higher values for CPL in summer than in winter. The values of CPL also are sensitive to the building's monthly load factor. We defined a statistical model capturing these effects, as follows.

1. To even out the distribution, we use the fourth power of the CPL (square of the responsibility factor); the data for each building and each month provide a set of sample pairs (LF_M, CPL^4). Both variables have a range from zero to one.
2. We distributed the data into a set of 10 x 10 bins, according to the values of CPL^4 and LF_M. The bin sizes are constant for each variable. An example of the distribution for summer data is shown in Figure 7-A.3.3.
3. We used the number of values in each bin, divided by the total number of values in the sample, as an estimate of the probability that CPL^4 is in a particular bin, given that the load factor is in a given bin.
4. We converted the probabilities into a distribution for CPL^2 by taking the square root of the bin limits defined for CPL^4.

Within the LCC, the building's monthly load factor is used as a proxy for the transformer load factor. For each month, we used the value of this load factor and the probability distribution defined above to select a random value for CPL^2, which then was used to calculate the demand savings from the load losses.

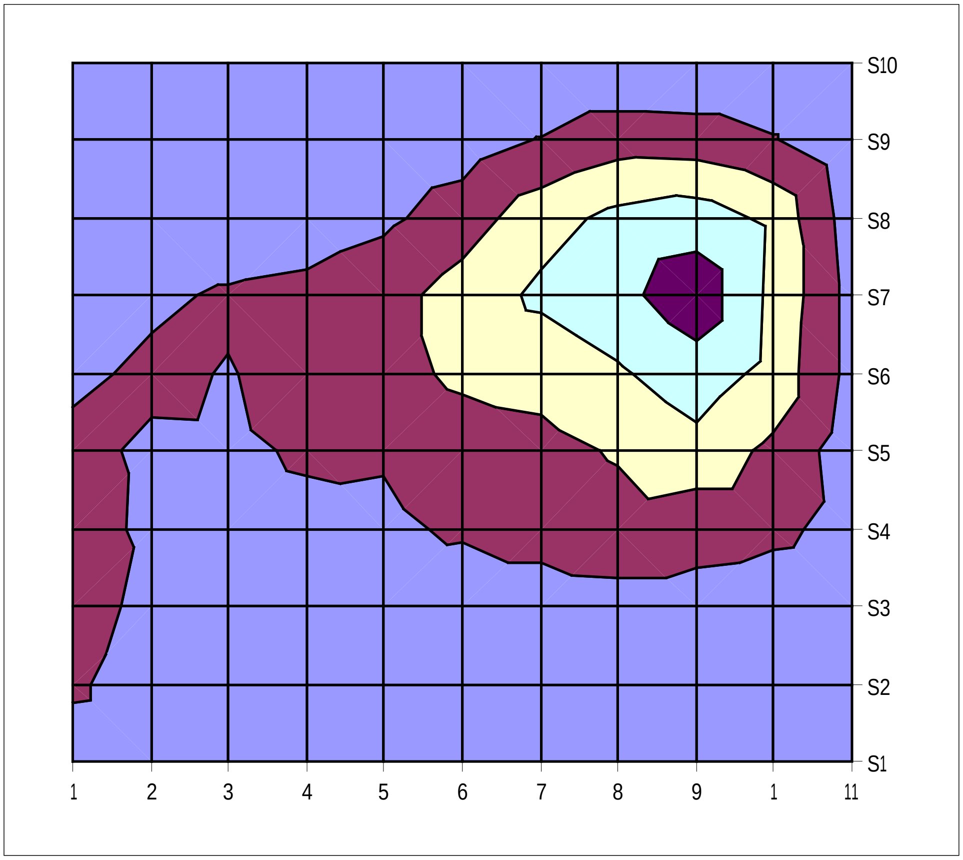

Figure 7A.3.4 Distribution of Values of the Pairs CPL^4 (Horizontal Axis) and LF_M (Vertical Axis), Summer

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APPENDIX 7B. SAMPLE UTILITIES

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APPENDIX 7B. SAMPLE UTILITIES

7B.1 SAMPLE UTILITIES

The following tables contain the list of electric utilities whose hourly load and lambda data were used in Chapter 7, with their designated service territories and Electricity Markets Module[1] (EMM) regions.

Table 7B.1.1 Definition of EMM Regions

Index	Abbreviation	Definition
1	ECAR	East Central Area Reliability Coordination Agreement
2	ERCOT	Electric Reliability Council of Texas
3	MAAC	Mid-Atlantic Area Council
4	MAIN	Mid-America Interconnected Network
5	MAPP	Mid-Continent Area Power Pool
6	NY	New York
7	NE	New England
8	FL	Florida Reliability Coordinating Council
9	SERC	Southeastern Electric Reliability Council
10	SPP	Southwest Power Pool
11	NPP	Northwest Power Pool
12	RA	Rocky Mountain Power Area
13	CA	California

Table 7B.1.2 Mapping of selected utilities to EMM Regions and Control Areas

EMM Region		Control Area Operator		Utility	
ID	Name	ID	Name	ID	Name
1	ECAR	5580	East Kentucky Power Cooperative	5580	East Kentucky Power Cooperative
1	ECAR	9267	Hoosier Energy REC Inc.	9267	Hoosier Energy REC Inc.
1	ECAR	9273	Indianapolis Power & Light Company	9273	Indianapolis Power & Light Company
1	ECAR	9273	Indianapolis Power & Light Company	40211	Wabash Valley Power Association Inc.
1	ECAR	11249	Louisville Gas & Electric and Kentucky Utilities	1692	Big Rivers Electric Corporation
1	ECAR	11249	Louisville Gas & Electric and Kentucky Utilities	11249	Louisville Gas & Electric and Kentucky Utilities
1	ECAR	13756	Northern Indiana Public Service Company	9234	Indiana Municipal Power Agency

1	ECAR	13756	Northern Indiana Public Service Company	13756	Northern Indiana Public Service Company
1	ECAR	13756	Northern Indiana Public Service Company	40211	Wabash Valley Power Association Inc.
1	ECAR	14725	PJM Interconnection LLC	14725	PJM Interconnection LLC
1	ECAR	17633	Southern Indiana Gas & Electric Company	17633	Southern Indiana Gas & Electric Company
1	ECAR	32208	FirstEnergy Corporation	32208	FirstEnergy Corporation
1	ECAR	99005	PJM Interconnection LLC	14725	PJM Interconnection LLC
1	ECAR	99006	PJM Interconnection LLC	14725	PJM Interconnection LLC
1	ECAR	99007	PJM Interconnection LLC	14725	PJM Interconnection LLC
2	ERCOT	5723	ERCOT	5723	ERCOT
3	MAAC	14725	PJM Interconnection LLC	14725	PJM Interconnection LLC
3	MAAC	99005	PJM Interconnection LLC	14725	PJM Interconnection LLC
3	MAAC	99006	PJM Interconnection LLC	14725	PJM Interconnection LLC
3	MAAC	99007	PJM Interconnection LLC	14725	PJM Interconnection LLC
4	MAIN	11479	Madison Gas & Electric Company	11479	Madison Gas & Electric Company
4	MAIN	14725	PJM Interconnection LLC	14725	PJM Interconnection LLC
4	MAIN	17828	City of Springfield	17828	City of Springfield
4	MAIN	20847	Wisconsin Electric Power Company	19578	Upper Peninsula Power Company
4	MAIN	20847	Wisconsin Electric Power Company	20847	Wisconsin Electric Power Company
4	MAIN	20847	Wisconsin Electric Power Company	20858	Wisconsin Public Power Inc.
4	MAIN	20847	Wisconsin Electric Power Company	20860	Wisconsin Public Service Corporation
4	MAIN	20856	Alliant Energy-East	20856	Alliant Energy-East
4	MAIN	99005	PJM Interconnection LLC	14725	PJM Interconnection LLC
4	MAIN	99006	PJM Interconnection LLC	14725	PJM Interconnection LLC
4	MAIN	99007	PJM Interconnection LLC	14725	PJM Interconnection LLC
5	MAPP	4716	Dairyland Power Cooperative	4716	Dairyland Power Cooperative
5	MAPP	9392	Alliant Energy-West	9392	Alliant Energy-West
5	MAPP	12431	MidAmerican Energy Company	12431	MidAmerican Energy Company
5	MAPP	13337	Nebraska Public Power District	11018	Lincoln Electric System
5	MAPP	13337	Nebraska Public Power District	13337	Nebraska Public Power District
5	MAPP	13781	Northern States Power Company	12647	Allete (Minnesota Power)
5	MAPP	13781	Northern States Power Company	12667	Minnesota Municipal Power Agency
5	MAPP	13781	Northern States Power Company	12710	Missouri River Energy Services
5	MAPP	13781	Northern States Power Company	12819	Montana-Dakota Utilities Company
5	MAPP	13781	Northern States Power Company	13781	Northern States Power Company
5	MAPP	13781	Northern States Power Company	13809	NorthWestern Energy (South Dakota)
5	MAPP	13781	Northern States Power Company	14232	Otter Tail Power Company
5	MAPP	13781	Northern States Power Company	17858	Square Butte Electric Coop

5	MAPP	13781	Northern States Power Company	40580	Southern Minnesota Municipal Power Agency
5	MAPP	14127	Omaha Public Power District	14127	Omaha Public Power District
5	MAPP	19514	Great River Energy	19514	Great River Energy
6	NY	13501	New York Independent System Operator Inc.	13501	New York Independent System Operator Inc.
7	NE	13434	ISO New England Inc.	13434	ISO New England Inc.
8	FL	6452	Florida Power & Light Company	6452	Florida Power & Light Company
8	FL	6455	Progress Energy (Florida Power Corp.)	6455	Progress Energy (Florida Power Corp.)
8	FL	6909	Gainsville Regional Utilities	6909	Gainsville Regional Utilities
8	FL	9617	JEA	9617	JEA
8	FL	14610	Orlando Utilities Commission	6567	Florida Municipal Power Agency
8	FL	14610	Orlando Utilities Commission	10623	Lakeland Electric
8	FL	14610	Orlando Utilities Commission	14610	Orlando Utilities Commission
8	FL	18445	City of Tallahassee	18445	City of Tallahassee
8	FL	18454	Tampa Electric Company	18454	Tampa Electric Company
8	FL	21554	Seminole Electric Cooperative Inc.	21554	Seminole Electric Cooperative Inc.
9	SERC	189	Alabama Electric Cooperative Inc.	189	Alabama Electric Cooperative Inc.
9	SERC	3046	Progress Energy (Carolina Power & Light Company)	3046	Progress Energy (Carolina Power & Light Company)
9	SERC	3046	Progress Energy (Carolina Power & Light Company)	7639	Greenville Utilities Commission
9	SERC	12506	Entergy Corporation/Services (Entergy System)	4280	City of Conway
9	SERC	12506	Entergy Corporation/Services (Entergy System)	9096	City of Lafayette Utilities System
9	SERC	12506	Entergy Corporation/Services (Entergy System)	12506	Entergy Corporation/Services (Entergy System)
9	SERC	12506	Entergy Corporation/Services (Entergy System)	13718	Duke Energy Control Area Services LLC (North Little Rock)
9	SERC	12506	Entergy Corporation/Services (Entergy System)	18679	Tex-La Electric Cooperative of Texas Inc.
9	SERC	12506	Entergy Corporation/Services (Entergy System)	26253	Louisiana Energy & Power Authority
9	SERC	12506	Entergy Corporation/Services (Entergy System)	40233	Sam Rayburn G&T Electric Coop.
9	SERC	14725	PJM Interconnection LLC	14725	PJM Interconnection LLC
9	SERC	17543	South Carolina Public Service Authority	17539	South Carolina Electric & Gas
9	SERC	17543	South Carolina Public Service Authority	17543	South Carolina Public Service Authority
9	SERC	17543	South Carolina Public Service Authority	40218	Central Electric Power Cooperative Inc.
9	SERC	17568	South Mississippi Electric Power Association	17568	South Mississippi Electric Power Association
9	SERC	18642	Tennessee Valley Authority	3408	Electric Power Board of Chattanooga
9	SERC	18642	Tennessee Valley Authority	4958	Decatur Utilities

9	SERC	18642	Tennessee Valley Authority	12293	Memphis Light Gas and Water
9	SERC	18642	Tennessee Valley Authority	18642	Tennessee Valley Authority
9	SERC	99005	PJM Interconnection LLC	14725	PJM Interconnection LLC
9	SERC	99006	PJM Interconnection LLC	14725	PJM Interconnection LLC
9	SERC	99007	PJM Interconnection LLC	14725	PJM Interconnection LLC
10	SPP	829	American Electric Power Company Inc.	829	American Electric Power Company Inc.
10	SPP	829	American Electric Power Company Inc.	13670	Northeast Texas Electric Cooperative
10	SPP	5860	Empire District Electric Company (the)	5860	Empire District Electric Company (the)
10	SPP	10015	Westar Energy (KPL)	10015	Westar Energy (KPL)
10	SPP	14063	Oklahoma Gas & Electric Company	7490	Grand River Dam Authority
10	SPP	14063	Oklahoma Gas & Electric Company	14063	Oklahoma Gas & Electric Company
10	SPP	14063	Oklahoma Gas & Electric Company	14077	Oklahoma Municipal Power Authority
10	SPP	17718	Southwestern Public Service Company (Xcel)	7349	Golden Spread Electric Cooperative Inc.
10	SPP	17718	Southwestern Public Service Company (Xcel)	17718	Southwestern Public Service Company (Xcel)
10	SPP	20447	Western Farmers Electric Cooperative	14077	Oklahoma Municipal Power Authority
10	SPP	20447	Western Farmers Electric Cooperative	20447	Western Farmers Electric Cooperative
11	NPP	17166	Sierra Pacific Resources	1738	Bonneville Power Administration USDOE
11	NPP	17166	Sierra Pacific Resources	3413	PUD No. 1 of Chelan County
11	NPP	17166	Sierra Pacific Resources	5326	PUD No. 1 of Douglas County
11	NPP	17166	Sierra Pacific Resources	6022	Eugene Water & Electric Board
11	NPP	17166	Sierra Pacific Resources	9191	Idaho Power Company
11	NPP	17166	Sierra Pacific Resources	12825	NorthWestern Energy
11	NPP	17166	Sierra Pacific Resources	14624	PUD No. 2 of Grant County
11	NPP	17166	Sierra Pacific Resources	15248	Portland General Electric Company
11	NPP	17166	Sierra Pacific Resources	15500	Puget Sound Energy Inc.
11	NPP	17166	Sierra Pacific Resources	16868	Seattle City Light
11	NPP	17166	Sierra Pacific Resources	17166	Sierra Pacific Resources
11	NPP	17166	Sierra Pacific Resources	18429	City of Tacoma Dept. of Public Utilities
11	NPP	17166	Sierra Pacific Resources	20169	Avista Corporation
11	NPP	17166	Sierra Pacific Resources	25471	Western Area Power Administration - Upper Missouri West (Upper Great Plains Regi
11	NPP	99004	PacifiCorp - Part II Sch 2 (East & West combined)	99004	PacifiCorp - Part II Sch 2 (East & West combined)
12	RA	803	Arizona Public Service Company	803	Arizona Public Service Company
12	RA	803	Arizona Public Service Company	19610	Western Area Power Administration - Lower Colorado control area (Desert Southwe

12	RA	5701	El Paso Electric Company	5701	El Paso Electric Company
12	RA	9216	Imperial Irrigation District	9216	Imperial Irrigation District
12	RA	13407	Nevada Power Company	13407	Nevada Power Company
12	RA	15466	Public Service Company of Colorado	3989	Colorado Springs Utilities
12	RA	15466	Public Service Company of Colorado	15143	Platte River Power Authority
12	RA	15466	Public Service Company of Colorado	15466	Public Service Company of Colorado
12	RA	15466	Public Service Company of Colorado	19545	Black Hills Corporation
12	RA	15466	Public Service Company of Colorado	30151	Tri-State G & T Assn. Inc.
12	RA	15473	Public Service Company of New Mexico	15473	Public Service Company of New Mexico
12	RA	15473	Public Service Company of New Mexico	30151	Tri-State G & T Assn. Inc.
12	RA	16572	Salt River Project	16572	Salt River Project
12	RA	24211	Tucson Electric Power Company	796	Arizona Electric Power Cooperative Inc.
12	RA	24211	Tucson Electric Power Company	24211	Tucson Electric Power Company
13	CA	229	California Independent System Operator	229	California Independent System Operator
13	CA	229	California Independent System Operator	16534	Sacramento Municipal Utility District (& City of Redding Electric Utility)
13	CA	11208	Los Angeles Department of Water and Power	2507	City of Burbank
13	CA	11208	Los Angeles Department of Water and Power	11208	Los Angeles Department of Water and Power
13	CA	19281	Turlock Irrigation District	19281	Turlock Irrigation District

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APPENDIX 8A. USER INSTRUCTIONS FOR LIFE-CYCLE COST AND PAYBACK PERIOD SPREADSHEETS

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APPENDIX 8A. USER INSTRUCTIONS FOR LIFE-CYCLE COST AND PAYBACK PERIOD SPREADSHEETS

To execute the LCC spreadsheet, it is necessary for the user to have the appropriate hardware and software tools. DOE assumed the user has a reasonably current computer operating under the Windows operating system. The development team uses relatively new systems and has not defined the minimum system requirements. At a minimum, users need Microsoft Excel to execute the spreadsheet. For full functionality in running Monte Carlo simulations, users will need a copy of a spreadsheet add-in called Crystal Ball, in addition to Excel. Without Crystal Ball, one can still use the LCC spreadsheet moEL, but will not be able to examine inputs and outputs as distributions. Approximate results are provided through a sample calculation that uses average values for the inputs and outputs, as displayed in the "Summary" worksheet.

8A.1 STARTUP

The LCC spreadsheet is a stored Excel file. It can be found on the DOE website at http://www.eere.energy.gov/buildings/appliance_standards/commercial/distribution_transformers.html. Open the file. (Each computer system will have a unique setup for loading a file. Users should refer to their software manuals if they have problems loading the spreadsheet file.) For users new to Excel and/or Crystal Ball, section 8.8.2 contains basic instructions for operating the LCC spreadsheets.

8A.1.1 Liquid-Immersed Transformers Worksheet Overview

Each of the LCC spreadsheets for the five liquid-immersed transformer design lines (DLs) contains the following worksheets:

8A.1.1.1 Options

This worksheet contains the variables used to create the spreadsheet options on the Summary worksheet.

8A.1.1.2 Description

The Life-Cycle Cost (LCC) spreadsheet is used to estimate consumer economic impacts of efficiency standards. It does this by calculating the present value impacts of two regulatory scenarios. The first scenario is a regulatory base case in which no standard is imposed, and the second is a standard case where future purchases of an appliance must conform to a minimum energy efficiency performance standard.

8A.1.1.3 Summary

This worksheet provides a summary of the LCC and PBP results for each draft efficiency level (EL). The spreadsheet/user interface is centered in the "Summary" worksheet. This worksheet contains a number of user-selectable options. These options, each with its own pull-down menu, are:

- Transformer Load Growth/Year
- Transformer Loading
- Electricity Prices
- Transformer Customer As & Bs
- Future Energy Price Trend
- Equipment Price Scenario
- Efficiency Standard Effective Date

Changing user-selectable options will produce average results shown on the "Summary," i.e., results using the mean inputs. Because of the very nature of Monte Carlo mathematics, the average results will not be identical to the mean of the distribution produced from Monte Carlo Crystal Ball simulations, but will provide quick feedback reflecting nominal results to spreadsheet users.

8A.1.1.4 Summary Results

This worksheet contains the summary results tables and chart from the most recent simulation.

8A.1.1.5 Capacity Costs

This worksheet contains utility capacity cost calculations for both regulated markets and markets with fully functioning capacity markets.

8A.1.1.6 A & B Dist.

This worksheet contains utility A and B models and data derived from utility transformer bids.

8A.1.1.7 Design Table

This worksheet contains the database of transformer design options. These are the results from the engineering analysis (Chapter 5). For each transformer design option these include: manufacture selling prices, and load and no-load loss coefficients. This worksheet also contains transformer markup and cost parameters and, for the appropriate design lines, pole cost parameters.

8A.1.1.8 System Loads

This worksheet contains the regional hourly electrical system load calculations as an input to the Price Load MoEL worksheet. This calculation is described in greater detail in Chapter 7.

8A.1.1.9 Price Load MoEL

This worksheet contains the regional hourly electrical system price calculations as an input to the Joint PDF worksheet. This calculation is described in greater detail in Chapter 7.

8A.1.1.10 Joint PDF

This worksheet calculates the load and system price of that load for the selected transformer and the probability of the transformer load being coincident with system peak. This calculation is described in greater detail in Chapter 7.

8A.1.1.11 Utilities

This worksheet provides a listing of the utilities and the operating regions that were used to determine system prices.

8A.1.1.12 LCC & Payback Calc.

This worksheet is used to estimate consumer economic impacts of efficiency standards. It does this by calculating the present value impacts of two regulatory scenarios. The first scenario is a regulatory base case in which no standard is imposed, and the second is a standard case where future purchases of an appliance must conform to a minimum energy efficiency performance standard.

8A.1.1.13 Annual Energy Price Forecast

This worksheet contains regional electricity price trend data for the analysis period.

8A.1.1.14 Discount Rate

This worksheet contains the discount rate analysis. It also contains the transformer market share data.

8A.1.1.15 Lifetime

This worksheet contains the transformer lifetime distribution.

8A.1.1.16 Forecast Cells

This worksheet contains the statistical results from the most recent simulation.

8A.1.2 Dry-Type Transformers Worksheet Overview

Each of the LCC spreadsheets for the eight dry-type transformer design lines contains the following worksheets:

8A.1.2.1 Options

This worksheet contains the variables used to create the spreadsheet options on the Summary worksheet.

8A.1.2.2 Description

The Life-Cycle Cost (LCC) spreadsheet is used to estimate consumer economic impacts of efficiency standards. It does this by calculating the present value impacts of two regulatory scenarios. The first scenario is a regulatory base case in which no standard is imposed, and the second is a standard case where future purchases of an appliance must conform to a minimum energy efficiency performance standard.

8A.1.2.3 Summary

This worksheet provides a summary of the LCC and PBP results for each draft efficiency level (EL). The spreadsheet/user interface is centered in the "Summary" worksheet. This worksheet contains a number of user-selectable options. These options, each with its own pull-down menu, are:

- Transformer Load Growth/Year
- Transformer Loading
- Electricity Prices
- Transformer Customer As & Bs
- Future Energy Price Trend
- Equipment Price Scenario
- Efficiency Standard Effective Date

Changing user-selectable options will produce average results shown on the "Summary," i.e., results using the mean inputs. Because of the very nature of Monte Carlo mathematics, the average results will not be identical to the mean of the distribution produced from Monte Carlo Crystal Ball simulations, but will provide quick feedback reflecting nominal results to spreadsheet users.

8A.1.2.4 Summary Results

This worksheet contains the summary results tables and chart from the most recent simulation.

8A.1.2.5 Design Table

This worksheet contains the database of transformer design options. These are the results from the engineering analysis (Chapter 5). For each transformer design option these include: manufacture selling prices, and load and no-load loss coefficients. This worksheet also contains transformer markup and cost parameters and, for the appropriate design lines, pole cost parameters.

8A.1.2.6 Demand & Usage

This worksheet contains the sample of transformer customers that are used in the simulation. For each of those customers this worksheet contains: monthly electricity demand and usage rates, seasonal marginal energy and demand prices, and A and B parameters.

8A.1.2.7 LCC & Payback Calc.

This worksheet is used to estimate consumer economic impacts of efficiency standards. It does this by calculating the present value impacts of two regulatory scenarios. The first scenario is a regulatory base case in which no standard is imposed, and the second is a standard case where future purchases of an appliance must conform to a minimum energy efficiency performance standard.

8A.1.2.8 Annual Energy Price Forecast

This worksheet contains regional electricity price trend data for the analysis period.

8A.1.2.9 Discount Rate

This worksheet contains the discount rate analysis. It also contains the transformer market share data.

8A.1.2.10 Lifetime

This worksheet contains the transformer lifetime distribution.

8A.1.2.11 Forecast Cells

This worksheet contains the statistical results from the most recent simulation.

8A.2 Basic Instructions for Operating the Life-Cycle Cost Spreadsheets

1. Once you have downloaded the LCC file from the Web, open the file using Excel. At the bottom, click on the tab for sheet "Summary."
2. Use Excel's View/Zoom commands at the top menu bar to change the size of the display to make it fit your monitor.
3. You can interact with the spreadsheet by clicking choices or entering data using the graphical interface that comes with the spreadsheet. Select choices from the various user-selectable options.
4. Click the "Run" button to run the simulation using DOE's parameters.

To produce custom sensitivity results using directly Crystal Ball, select *Run* from the *Run* menu (on the menu bar). To make basic changes in the *Run* sequence, including altering the number of trials, select *Run Preferences* from the *Run* menu. After each simulation run, the user needs to select *Reset* (also from the *Run* menu) before *Run* can be selected again. Once Crystal Ball has completed its run sequence, it will produce a series of distributions. Using the menu bars on the distribution results, it is possible to obtain further statistical information. The time taken to complete a run sequence can be reduced by minimizing the Crystal Ball window in Excel. A step-by-step summary of the procedure for running a distribution analysis is outlined below:

1. Find the Crystal Ball toolbar (at top of screen).
2. Click on *Run* from the menu bar.
3. Select *Run Preferences* and choose either Monte Carlo or Latin Hypercube.[a] Select number of Trials (DOE suggests 10,000).
4. To run the simulation, choose the following sequence (on the Crystal Ball toolbar): *Run, Reset, Run*
5. Now wait until the program informs you that the simulation is completed.

DOE provides the following instructions to view the output generated by Crystal Ball:

1. After the simulation has finished, click on the Windows tab bar labeled Crystal Ball to see the distribution charts.

2. The LCC savings and paybacks are defined as *Forecast* cells. The frequency charts display the results of the simulations, or trials, performed by Crystal Ball. Click on any chart to bring it into view. The charts show the low and high endpoints of the forecasts. The *View* selection on the Crystal Ball toolbar can be used to specify whether cumulative or frequency plots are to be shown.

   2a. To calculate the probability that a particular value of LCC savings will occur, either type 0 in the box by the left arrow, or move the arrow key with the cursor to 0 on

[a]Because of the nature of the program, there is some variation in results due to random sampling when MonteCarlo or Latin Hypercube sampling is used.

the scale. The value in the *Certainty* box shows the likelihood that the LCC savings will occur.

2b. To calculate the certainty of the payback period being below a certain number of years, insert that value in the far-right box.

3. To generate a printed report, select *Create Report* from the *Run* menu. The toolbar choice of *Forecast Windows* allows you to select the charts and statistics in which you are interested. For further information on Crystal Ball outputs, refer to *Understanding the Forecast Chart* in the Crystal Ball manual.

APPENDIX 8B. UNCERTAINTY AND VARIABILITY

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APPENDIX 8B. UNCERTAINTY AND VARIABILITY

8B.1 INTRODUCTION

Analysis of a potential energy efficiency standard involves calculating effects, for example, the effect of a standard on consumer life-cycle cost (LCC). To perform the calculation, the analyst must first: (1) specify the equation or model that will be used; (2) define the quantities in the equation or model; and (3) provide numerical values for each quantity. In the simplest case, the equation is unambiguous (it contains all relevant quantities and no others), each quantity has a single numerical value, and the calculation produces a single value. Unambiguousness and precision are rarely the case, however. In most 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. Although the simplest analysis involves a single numerical value for each quantity in the calculation, arguments can arise about the appropriate value for each quantity. Explicit analysis of uncertainty and variability provides 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 consumed by a particular type of appliance (such as the average residential clothes washer) is not recorded directly, but rather estimated based on available information. Even direct laboratory measurements have a margin of error. When estimating numerical values expected for quantities at some future date, the exact outcome rarely is known.

8B.3 VARIABILITY

Variability in the calculation of a quantity means that different applications or situations produce different numerical values. Specifying an exact value for a quantity may be difficult because the value depends on something else. For example, the number of hours a household operates a clothes washer depends on the specific circumstances and behaviors of the occupants (*e.g.*, number of persons, personal habits). Variability makes specifying an appropriate population value more difficult, because no one value is likely to 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.*, number of 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. Numerous calculations are performed, which provide some indication of the extent to which the result depends on the assumptions. For example, the LCC of an appliance could be calculated based on electricity costs of 2, 8, and 14 cents per kilowatt-hour.

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 LCC is reduced, holding all other inputs constant; that is, the energy rate at which the consumer achieves savings in operating costs that more than compensate for the increased purchase price.) 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 characterized by 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 subject to electricity rates at particular levels) to estimate the probability of each value. For quantities characterized by uncertainty, statistical or subjective measures can be used to provide probabilities (*e.g.*, manufacturing cost to improve energy efficiency to a given 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 more 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 a policy given the identified 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 analyses, DOE used Microsoft Excel spreadsheets combined with Crystal Ball, a commercially available add-in software, to conduct probability analyses. The probability analyses used Monte Carlo simulation and probability distributions.

Simulation refers to any analytical method meant to duplicate a real-life system, especially when other analyses are too mathematically complex or difficult to reproduce. Without the aid of simulation, a spreadsheet model will reveal only a single outcome, generally the most likely or average outcome. 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 numerous times. 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 number for any particular roll. So too with variables that have a known range of values but an uncertain value for any particular time or event (*e.g.*, product lifetime, discount rate, and installation cost).

For each uncertain variable (a variable that has a range of possible values), a probability distribution is used to define possible values. The type of distribution selected is based on the conditions surrounding that variable. Types of probability distributions include the following.

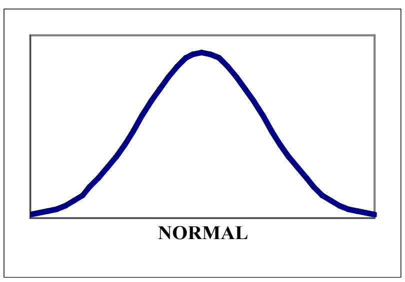

Figure 8B.5.1 Normal Probability Distribution

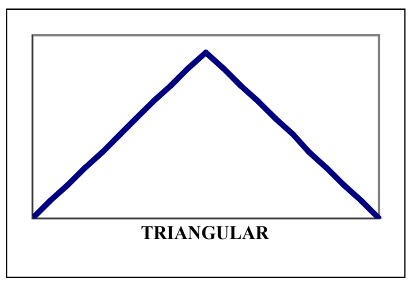

Figure 8-B.5.2 Triangular Probability Distribution

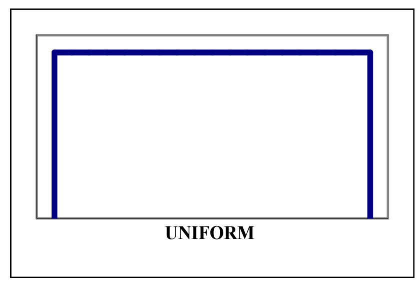

Figure 8-B.5.3 Uniform Probability Distribution

During a simulation, multiple scenarios are calculated by sampling values repeatedly from the probability distributions for the uncertain variables. 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. LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS

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APPENDIX 8C. LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS

8C.1 LIFE-CYCLE COST & PAYBACK RESULTS FOR LIQUID-IMMERSED TRANSFORMERS, DESIGN LINES 1-5

8C.1.1 Design Line 1 Results

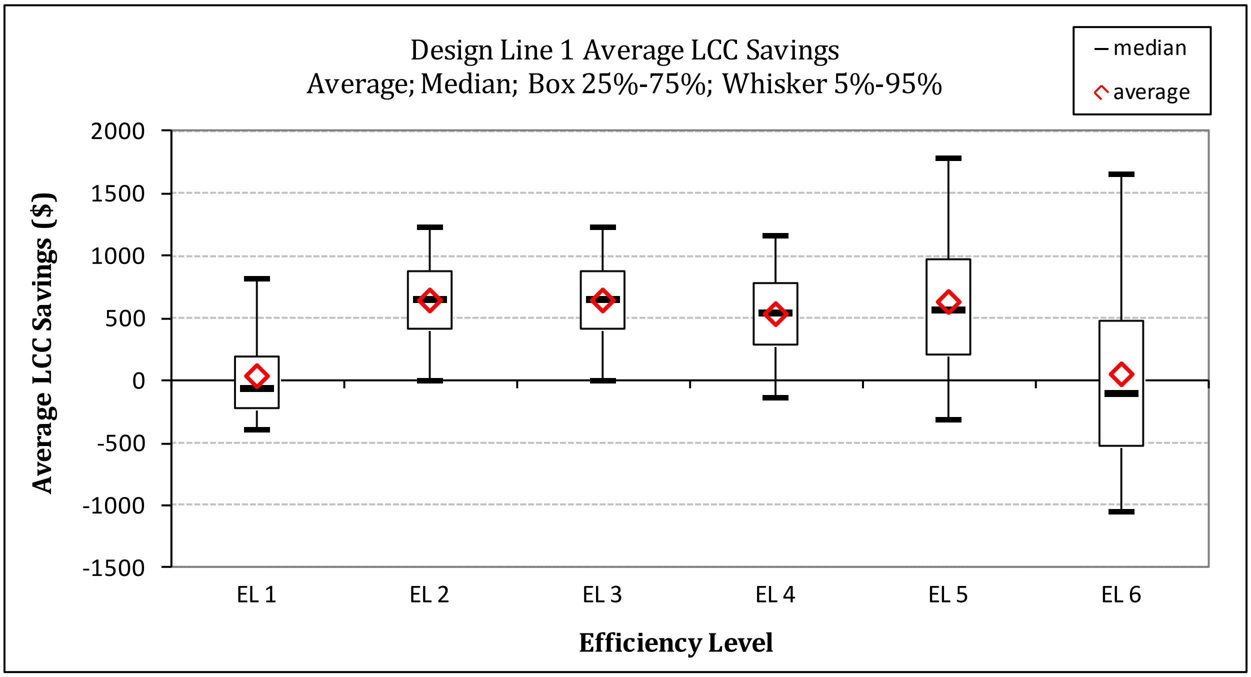

Figure 8C.1.1 Design Line 1, Range of LCC Savings by Efficiency Level

Table 8C.1.1 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.16	99.22	99.25	99.31	99.42	99.50
Transformers with Net Increase in LCC (%)	57.94	4.77	4.77	8.00	13.63	55.36
Transformers with No Impact on LCC (%)	0.23	0.23	0.23	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	41.83	95.00	95.00	92.00	86.37	44.64
Mean LCC Savings ($)	36	641	641	532	629	50
Median LCC Savings ($)	-64	650	650	540	563	-104

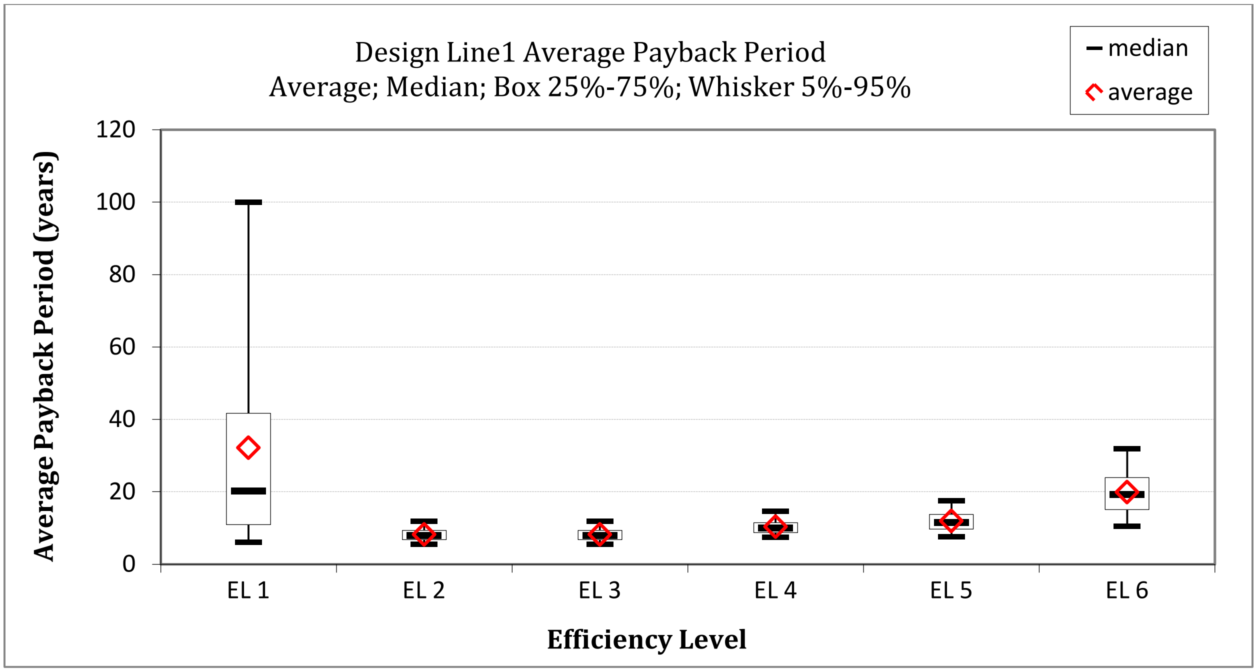

Figure 8C.1.2 Design Line 1, Range of Payback Periods by Efficiency Level

Table 8C.1.2 Summary Payback Period Results for Design Line 1 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	32.2	8.2	8.2	10.4	12.0	19.9
Median Payback (Years)	20.2	7.9	7.9	10.0	11.5	19.2
Transformers having Well Defined Payback (%)	85.02	99.77	99.77	99.89	99.99	99.95
Transformers having Undefined Payback (%)	14.98	0.23	0.23	0.11	0.01	0.05
Mean Retail Cost ($)	2,244	2,446	2,446	2,549	2,802	3,333
Mean Installation Costs ($)	2,230	2,271	2,271	2,344	2,415	2,606
Mean Operating Costs ($)	209	156	156	153	132	126
Mean Incremental First Cost ($)	327	569	569	746	1,070	1,792
Mean Operating Cost Savings ($)	18	71	71	74	95	100
Payback of Average Transformer	18.2	8.0	8.0	10.1	11.2	17.8

8C.1.2 Design Line 2 Results

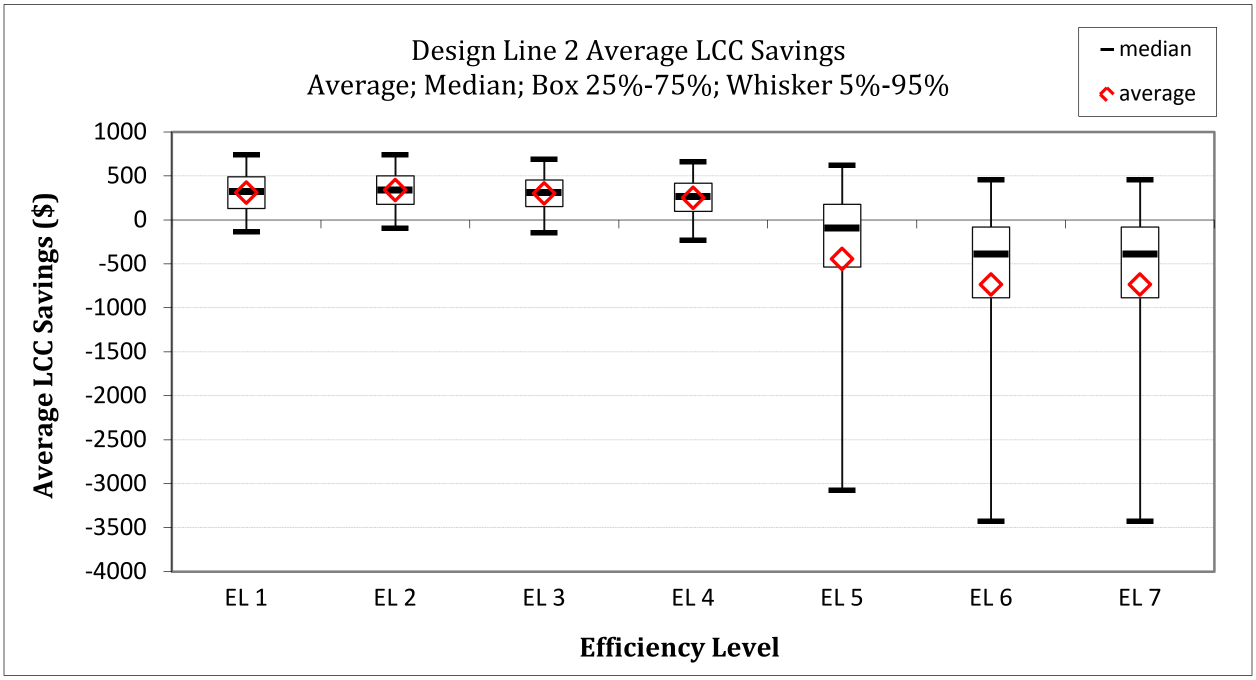

Figure 8C.1.3 Design Line 2, Range of LCC Savings by Efficiency Level

Table 8C.1.3 Summary Life-Cycle Cost Results for Design Line 2 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.00	99.07	99.11	99.18	99.31	99.41	99.46
Transformers with Net LCC Cost (%)	14.23	9.82	11.20	15.75	58.18	80.16	86.51
Transformers with No Change in LCC (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transformers with Net LCC Benefit (%)	85.77	90.18	88.80	84.25	41.82	19.84	13.49
Mean LCC Savings ($)	309	338	300	250	-445	-736	-599
Median LCC Savings ($)	322	341	308	262	-91	-390	-535

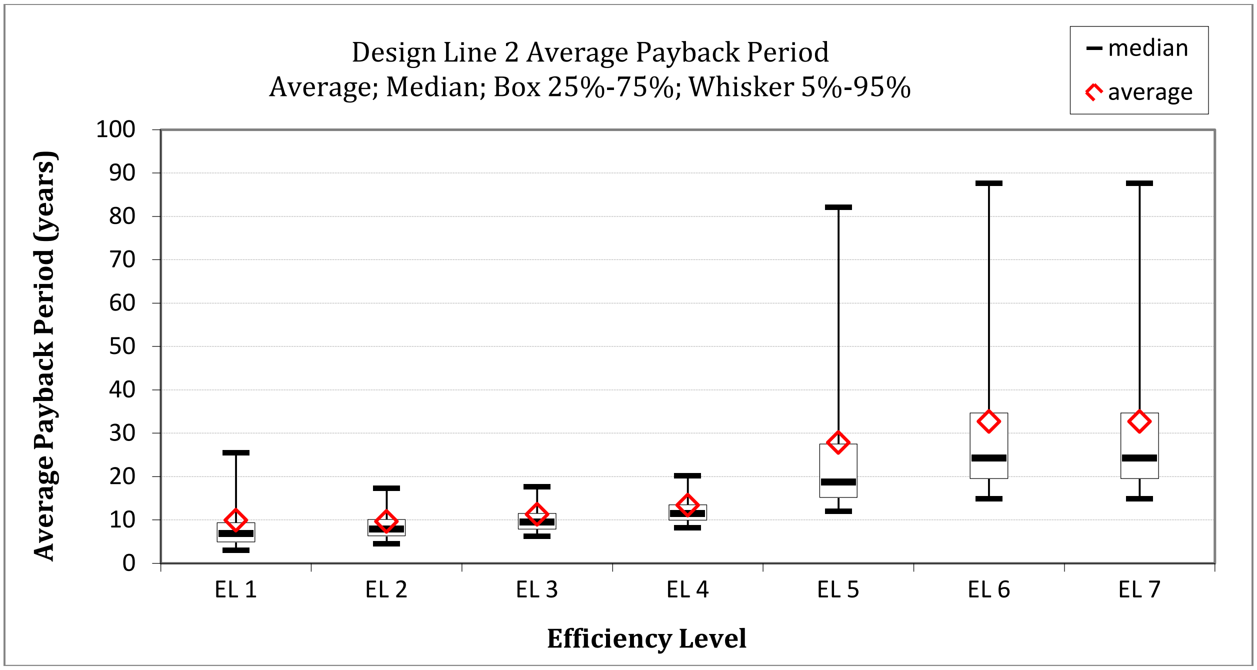

Figure 8C.1.4 Design Line 2, Range of Payback Periods by Efficiency Level

Table 8C.1.4 Summary Payback Period Results for Design Line 2 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	10.0	9.7	11.3	13.4	27.9	32.7	30.3
Median Payback (Years)	6.9	8.0	9.5	11.5	18.7	24.3	26.3
Transformers having Well Defined Payback (%)	98.55	99.93	99.71	99.83	99.75	99.77	99.90
Transformers having Undefined Payback (%)	1.45	0.07	0.29	0.17	0.25	0.23	0.10
Mean Retail Cost ($)	1,437	1,480	1,530	1,598	1,846	2,052	2,577
Mean Installation Costs ($)	1722	1761	1790	1859	2500	2678	2093
Mean Operating Costs ($)	101	95	93	89	79	75	71
Mean Incremental First Cost ($)	235	317	396	533	1,422	1,807	1,746
Mean Operating Cost Savings ($)	34	40	41	46	55	60	64
Payback of Average Transformer	7.0	8.0	9.6	11.7	25.8	30.2	27.4

8C.1.3 Design Line 3 Results

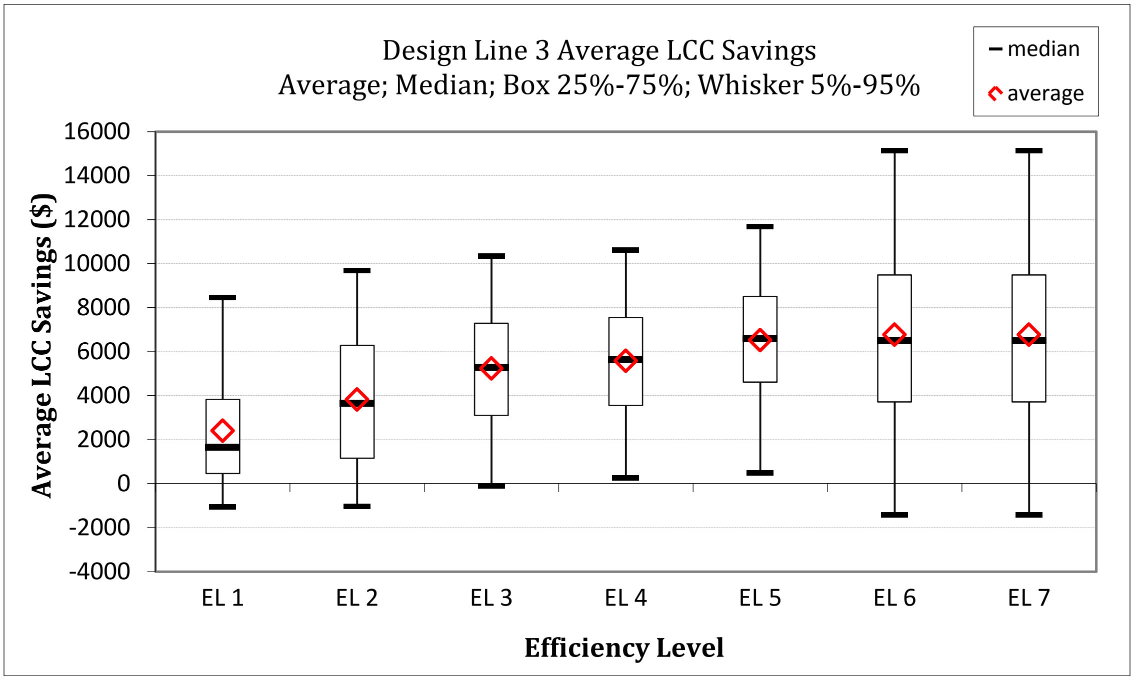

Figure 8C.1.5 Design Line 3, Range of LCC Savings by Efficiency Level

Table 8C.1.5 Summary Life-Cycle Cost Results for Design Line 3 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.48	99.51	99.54	99.57	99.61	99.69	99.73
Transformers with Net Increase in LCC (%)	15.68	11.17	5.33	4.02	3.87	7.60	25.07
Transformers with No Impact on LCC (%)	1.35	1.18	0.03	0.02	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	82.97	87.65	94.64	95.96	96.13	92.40	74.93
Mean LCC Savings ($)	2413	3831	5245	5591	6531	6780	4135
Median LCC Savings ($)	1665	3664	5304	5642	6593	6500	3301

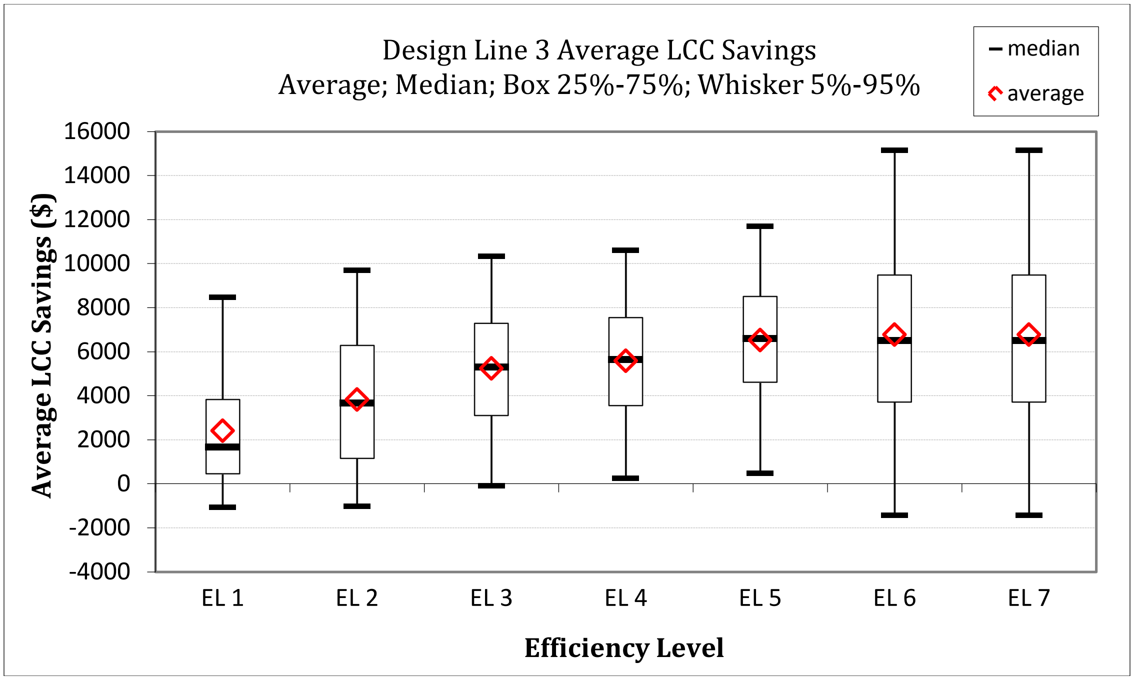

Figure 8C.1.6 Design Line 3, Range of Payback Periods by Efficiency Level

Table 8C.1.6 Summary Payback Period Results for Design Line 3 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	9.2	6.7	5.6	5.5	6.1	9.6	15.4
Median Payback (Years)	6.3	4.0	4.6	4.7	5.2	8.1	13.3
Transformers having Well Defined Payback (%)	94.83	96.53	99.82	99.97	100.00	99.91	99.65
Transformers having Undefined Payback (%)	5.17	3.47	0.18	0.03	0.00	0.09	0.35
Mean Retail Cost ($)	8,550	8,942	9,535	9,678	10,280	12,499	15,917
Mean Installation Costs ($)	4,333	4,311	4,370	4,402	4,523	4,997	5,679
Mean Operating Costs ($)	1,203	1,085	966	939	857	714	650
Mean Incremental First Cost ($)	938	1,308	1,960	2,135	2,858	5,550	9,650
Mean Operating Cost Savings ($)	201	319	439	465	547	690	754
Payback of Average Transformer	4.7	4.1	4.5	4.6	5.2	8.0	12.8

8C.1.4 Design Line 4 Results

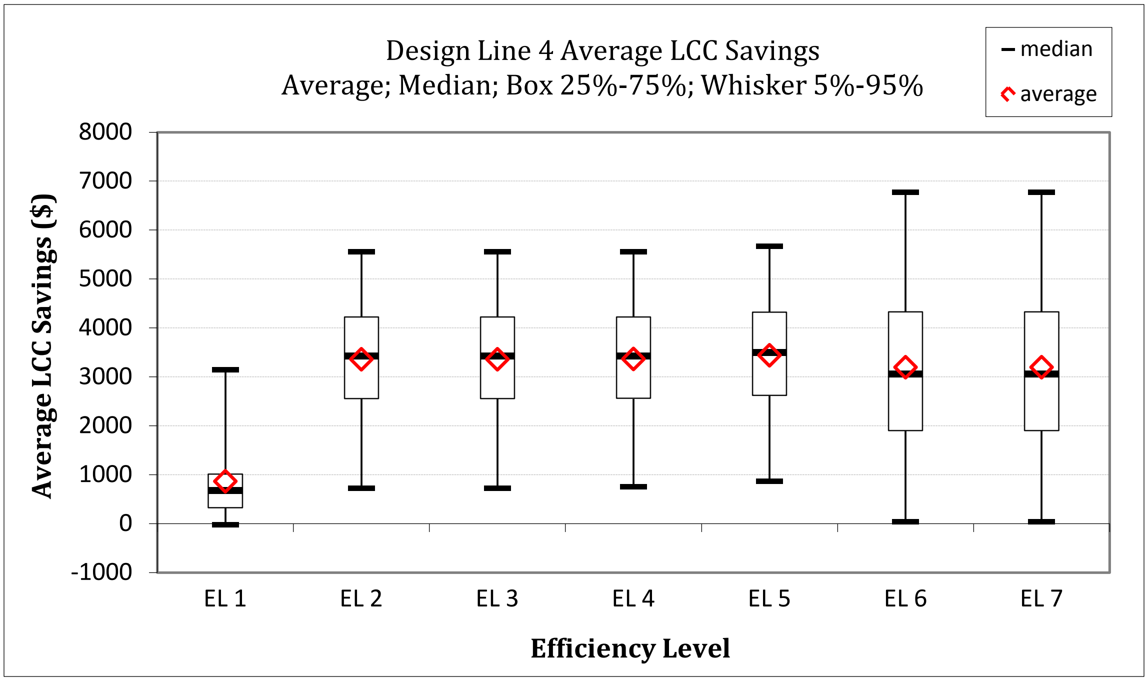

Figure 8C.1.7 Design Line 4, Range of LCC Savings by Efficiency Level

Table 8C.1.7 Summary Life-Cycle Cost Results for Design Line 4 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.16	99.22	99.25	99.31	99.42	99.50	99.60
Transformers with Net LCC Cost (%)	5.95	1.91	1.91	1.86	1.82	4.87	31.10
Transformers with No Change in LCC (%)	0.58	0.58	0.58	0.58	0.17	0.00	0.00
Transformers with Net LCC Benefit (%)	93.47	97.51	97.51	97.56	98.01	95.13	63.87
Mean LCC Savings ($)	862	3356.0	3356.0	3362.3	3437.2	3193	1274
Median LCC Savings ($)	670	3418.7	3418.7	3423.6	3489.8	3054	956

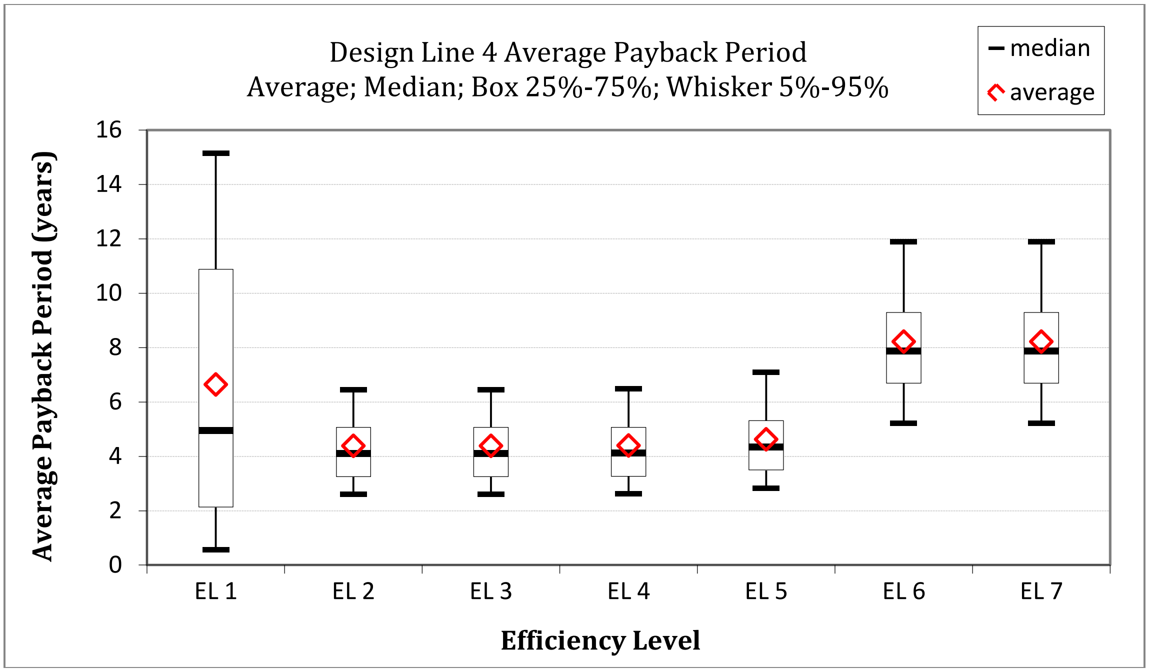

Figure 8C.1.8 Design Line 4, Range of Payback Periods by Efficiency Level

Table 8C.1.8 Summary Payback Period Results for Design Line 4 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	6.6	4.4	4.4	4.4	4.6	8.2	15.1
Median Payback (Years)	5.0	4.1	4.1	4.1	4.3	7.9	14.6
Transformers having Well Defined Payback (%)	99.37	99.27	99.27	99.33	99.81	99.94	94.96
Transformers having Undefined Payback (%)	0.63	0.73	0.73	0.67	0.19	0.06	0.01
Mean Retail Cost ($)	5,894	6,443	6,443	6,451	6,536	7,615	10,601
Mean Installation Costs ($)	4,090	4,184	4,184	4,183	4,223	4,584	4,709
Mean Operating Costs ($)	668	483	483	482	471	400	334
Mean Incremental First Cost ($)	438	1,081	1,081	1,088	1,214	2,653	5,763
Mean Operating Cost Savings ($)	76	261	261	262	274	344	414
Payback of Average Transformer	5.7	4.1	4.1	4.1	4.4	7.7	13.9

8C.1.5 Design Line 5 Results

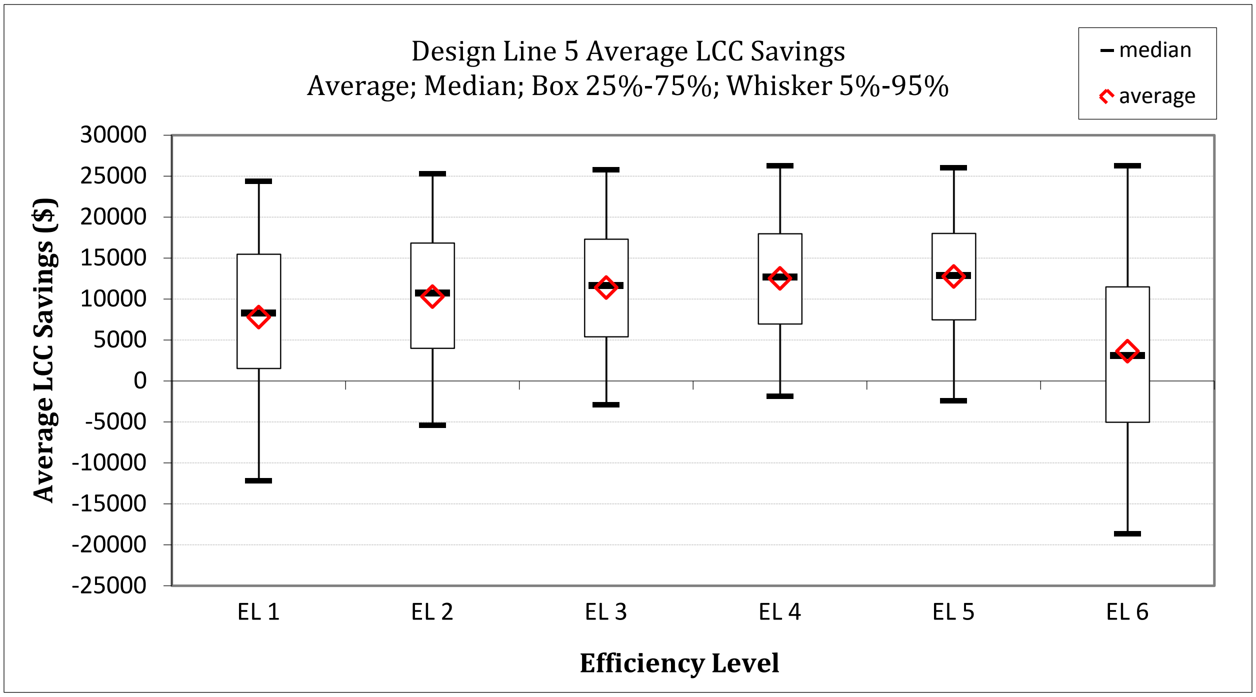

Figure 8C.1.9 Design Line 5, Range of LCC Savings by Efficiency Level

Table 8C.1.9 Summary Life-Cycle Cost Results for Design Line 5 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.48	99.51	99.54	99.57	99.61	99.69
Transformers with Net Increase in LCC (%)	19.05	13.15	10.41	7.77	7.88	39.92
Transformers with No Impact on LCC (%)	0.39	0.09	0.01	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	80.56	86.76	89.58	92.23	92.12	60.08
Mean LCC Savings ($)	7787	10288	11395	12513	12746	3626
Median LCC Savings ($)	8300	10741	11658	12666	12838	3083

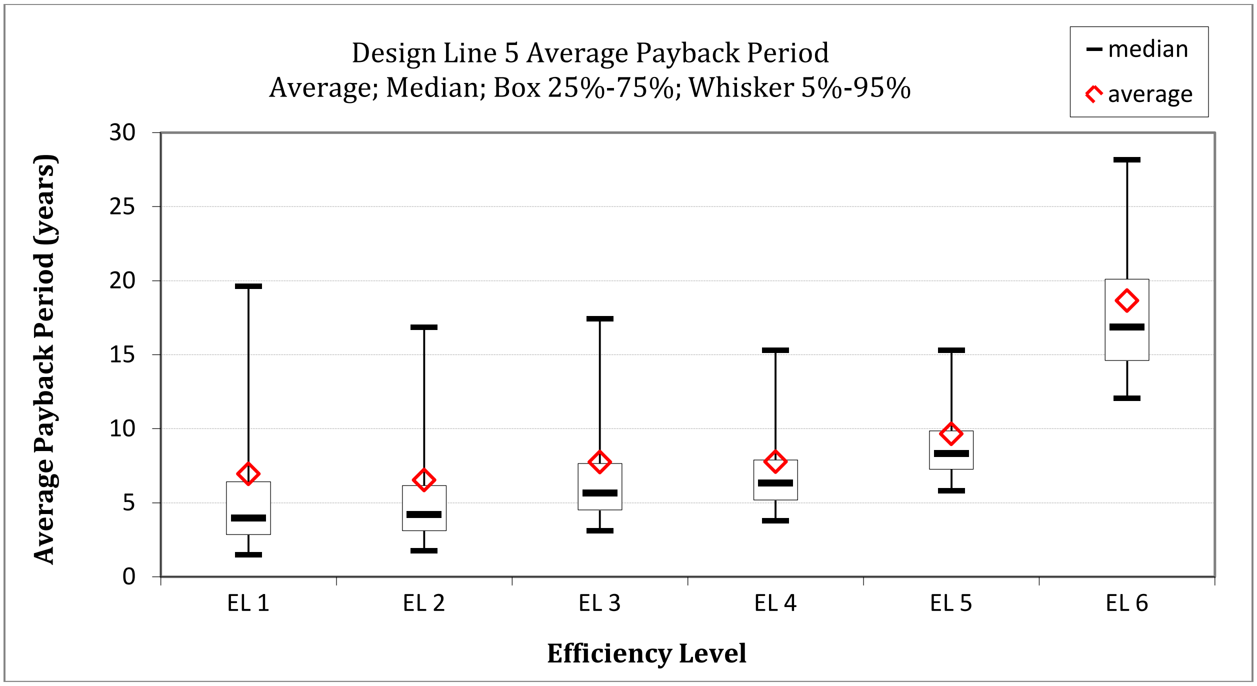

Figure 8C.1.10 Design Line 5, Range of Payback Periods by Efficiency Level

Table 8C.1.10 Summary Payback Period Results for Design Line 5 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	7.0	6.5	7.8	7.8	9.7	18.7
Median Payback (Years)	4.0	4.2	5.7	6.3	8.3	16.9
Transformers having Well Defined Payback (%)	91.63	96.04	98.89	99.82	99.97	100.00
Transformers having Undefined Payback (%)	8.37	3.96	1.11	0.18	0.03	0.00
Mean Retail Cost ($)	28,574	29,040	30,872	31,980	35,448	56,798
Mean Installation Costs ($)	8,551	8,631	8,875	9,030	9,498	9,834
Mean Operating Costs ($)	3,407	3,259	3,105	2,994	2,802	2,185
Mean Incremental First Cost ($)	3,296	3,842	5,918	7,181	11,116	32,803
Mean Operating Cost Savings ($)	718	866	1,020	1,131	1,323	1,940
Payback of Average Transformer	4.6	4.4	5.8	6.3	8.4	16.9

8C.2 LIFE-CYCLE COST & PAYBACK RESULTS FOR LOW-VOLTAGE DRY TYPE TRANSFORMERS, DESIGN LINES 6-8

8C.2.1 Design Line 6 Results

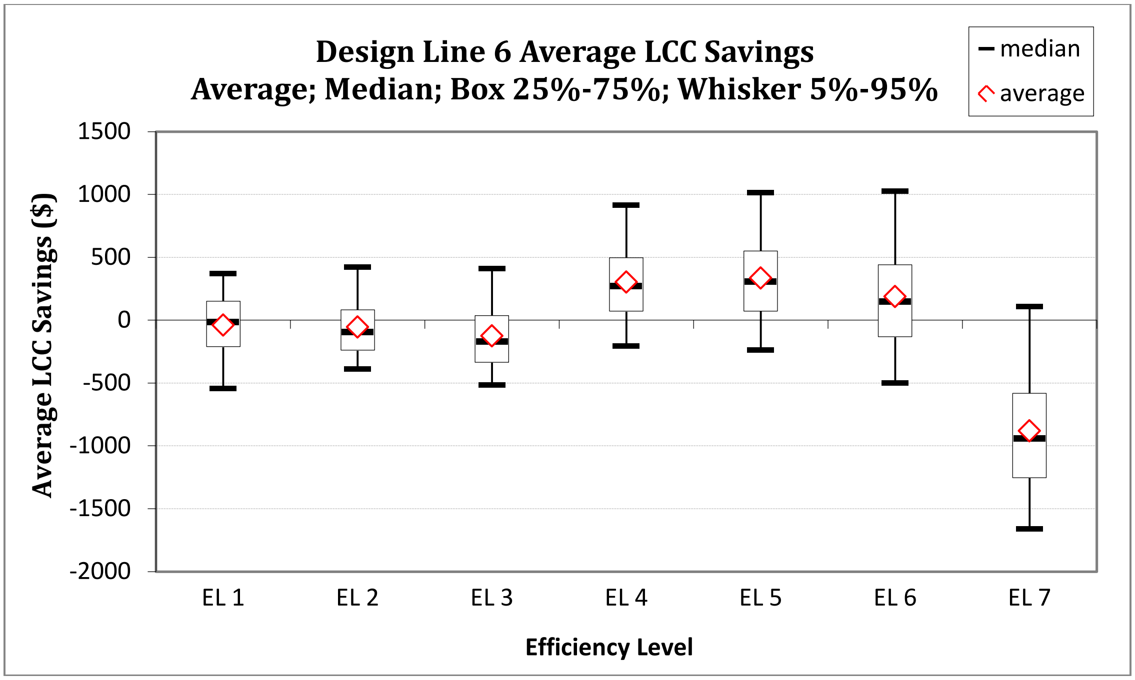

Figure 8C.2.1 Design Line 6, Range of LCC Savings by Efficiency Level

Table 8C.2.1 Summary Life-Cycle Cost Results for Design Line 6 Representative Unit

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23	98.47	98.60	98.80	98.93	99.17	99.44
Transformers with Net Increase in LCC (%)	51.85	64.97	71.51	17.59	17.57	36.16	93.36
Transformers with Net LCC Savings (%)	47.95	35.03	28.49	82.41	82.43	63.84	6.64
Transformers with No Impact on LCC (%)	0.20	0.00	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	-39	-55	-125	303	335	187	-881
Median LCC Savings ($)	-14	-96	-172	270	306	147	-940

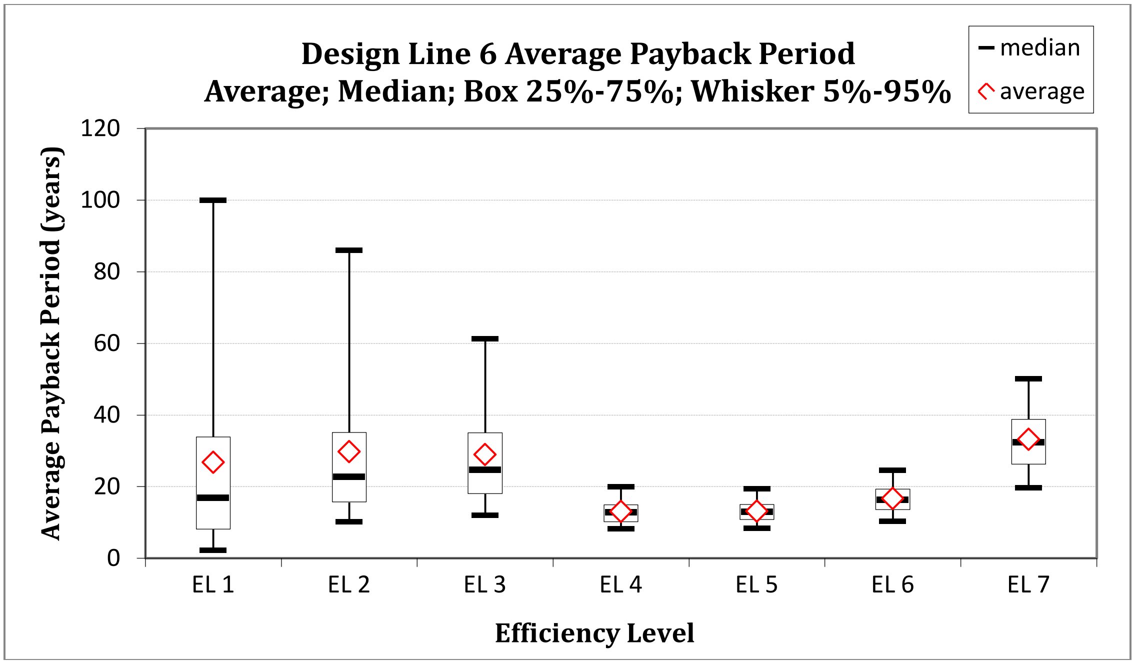

Figure 8C.2.2 Design Line 6, Range of Payback Periods by Efficiency Level

Table 8C.2.2 Summary Payback Period Results for Design Line 6 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	26.8	29.8	29.0	13.1	13.2	16.7	33.2
Median Payback (Years)	16.9	22.7	24.7	12.8	13.0	16.3	32.4
Transformers having Well Defined Payback (%)	91.32	99.04	99.94	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	8.68	0.96	0.06	0.00	0.00	0.00	0.00
Mean Retail Cost ($)	1,208	1,272	1,403	1,683	1,743	1,977	2,864
Mean Installation Costs ($)	1,202	1,305	1,369	1,026	1,059	1,164	1,490
Mean Operating Costs ($)	140	132	125	106	99	89	81
Mean Incremental First Cost ($)	275	442	638	573	667	1,006	2,220
Mean Operating Cost Savings ($)	13	21	28	47	54	64	72
Payback of Average Transformer	21.6	21.2	23.1	12.1	12.3	15.6	30.7

8C.2.2 Design Line 7 Results

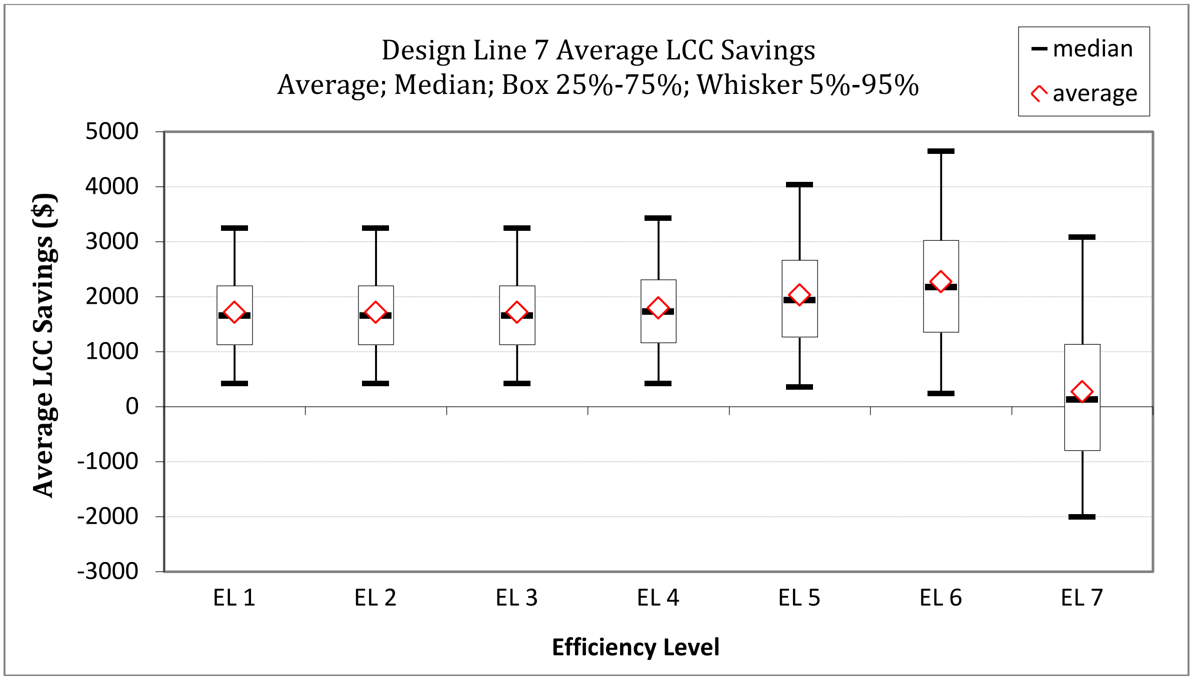

Figure 8C.2.3 Design Line 7, Range of LCC Savings by Efficiency Level

Table 8C.2.3 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	98.23	98.47	98.60	98.80	98.93	99.17	99.44
Transformers with Net Increase in LCC (%)	1.8	1.8	1.8	2.0	2.8	3.7	46.4
Transformers with No Impact on LCC (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transformers with Net LCC Savings (%)	98.2	98.2	98.2	98.0	97.2	96.3	53.6
Mean LCC Savings ($)	1714	1714	1714	1793	2030	2270	270
Median LCC Savings ($)	1649	1649	1649	1724	1931	2174	123

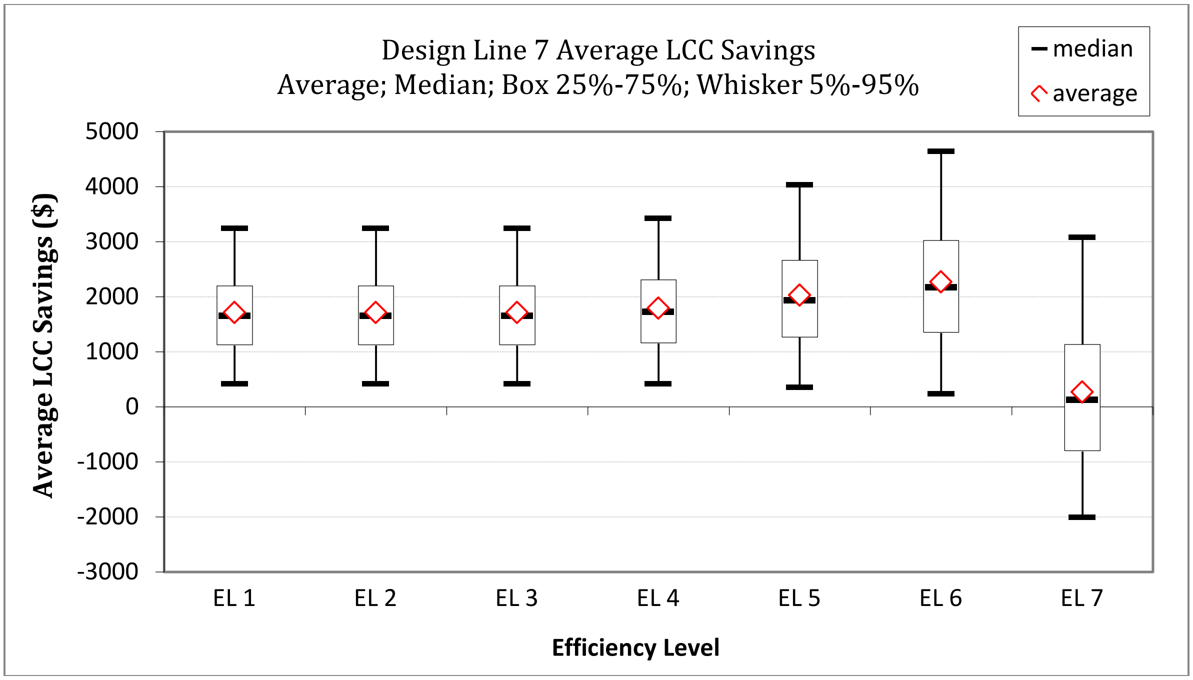

Figure 8C.2.4 Design Line 7, Range of Payback Periods by Efficiency Level

Table 8C.2.4 Summary Payback Period Results for Design Line 7 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	4.7	4.7	4.7	4.9	5.9	7.0	18.6
Median Payback (Years)	4.5	4.5	4.5	4.7	5.8	6.9	18.1
Transformers having Well Defined Payback (%)	100	100	100	100	100	100	100
Transformers having Undefined Payback (%)	0	0	0	0	0	0	0
Mean Retail Cost	3,537	3,537	3,537	3,583	3,881	4,161	6,049
Mean Installation Costs ($)	1,743	1,743	1,743	1,761	1,731	1,839	2,362
Mean Operating Costs ($)	222	222	222	214	187	153	131
Mean Incremental First Cost ($)	531	531	531	594	863	1,250	3,662
Mean Operating Cost Savings ($)	121	121	121	129	156	190	212
Payback of Average Transformer	4.4	4.4	4.4	4.6	5.5	6.6	17.3

8C.2.3 Design Line 8 Results

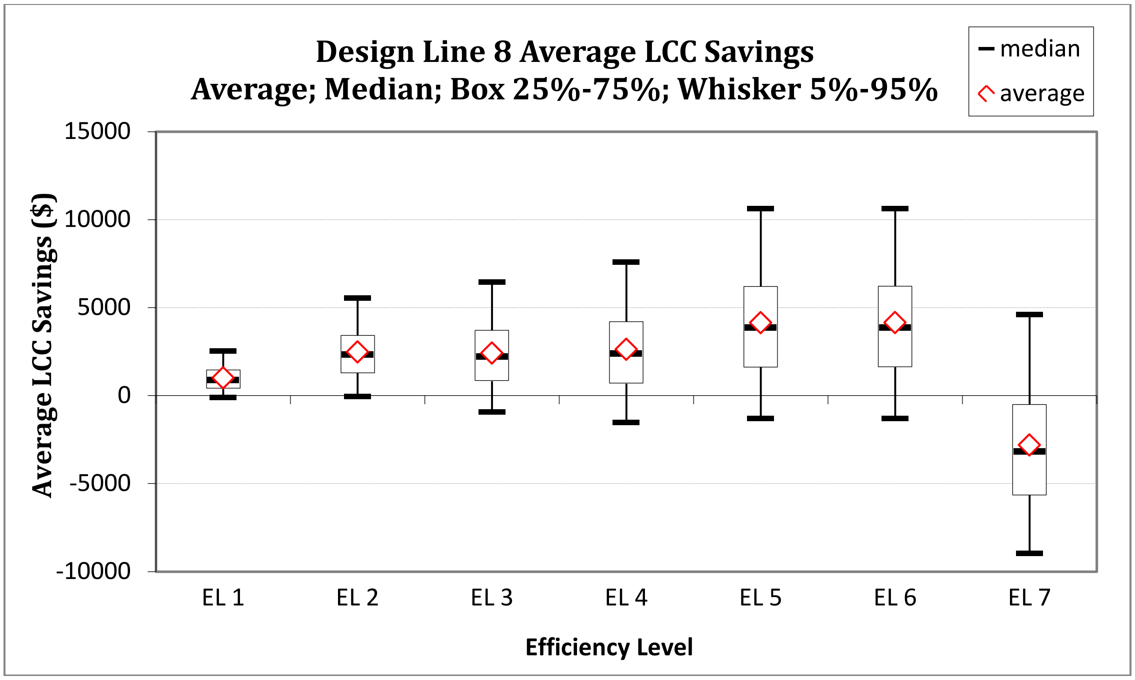

Figure 8C.2.5 Design Line 8, Range of LCC Savings by Efficiency Level

Table 8C.2.5 Summary Life-Cycle Cost Results for Design Line 8 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	98.80	99.02	99.14	99.25	99.32	99.44	99.58
Transformers with Net Increase in LCC (%)	7.61	5.18	12.24	15.33	10.51	10.46	78.46
Transformers with No Impact on LCC (%)	92.39	94.82	87.76	84.67	89.49	89.54	21.54
Transformers with Net LCC Savings (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	1004	2476	2412	2625	4137	4145	-2812
Median LCC Savings ($)	882	2329	2211	2388	3858	3867	-3171

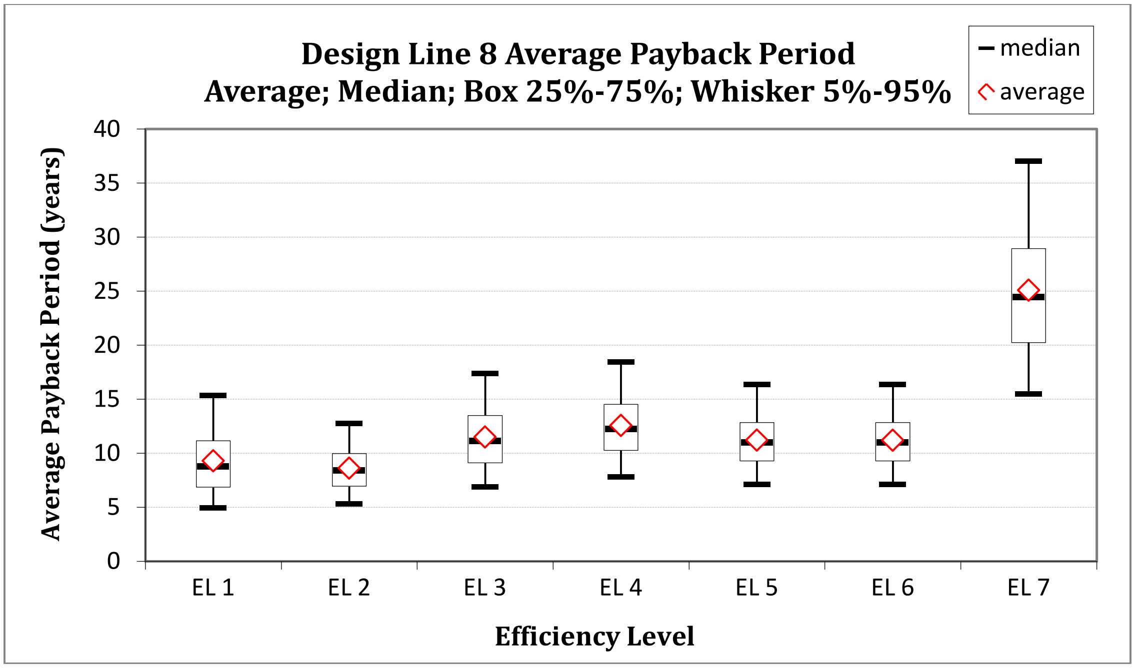

Figure 8C.2.6 Design Line 8, Range of Payback Periods by Efficiency Level

Table 8C.2.6 Summary Payback Period Results for Design Line 8 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	9.3	8.6	11.5	12.6	11.2	11.2	25.1
Median Payback (Years)	8.8	8.4	11.1	12.3	11.0	11.0	24.5
Transformers having Well Defined Payback (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mean Retail Cost ($)	7,463	8,411	9,700	10,851	11,784	11,782	19,031
Mean Installation Costs ($)	2,850	2,999	3,126	3,221	3,158	3,158	3,905
Mean Operating Costs ($)	739	600	527	449	320	320	264
Mean Incremental First Cost ($)	807	1,905	3,321	4,567	5,437	5,435	13,430
Mean Operating Cost Savings ($)	98	236	309	388	517	517	573
Payback of Average Transformer	8.3	8.1	10.7	11.8	10.5	10.5	23.4

8C.3 LIFE-CYCLE COST & PAYBACK RESULTS FOR LOW-VOLTAGE DRY TYPE TRANSFORMERS, DESIGN LINES 9-13B

8C.3.4 Design Line 9 Results

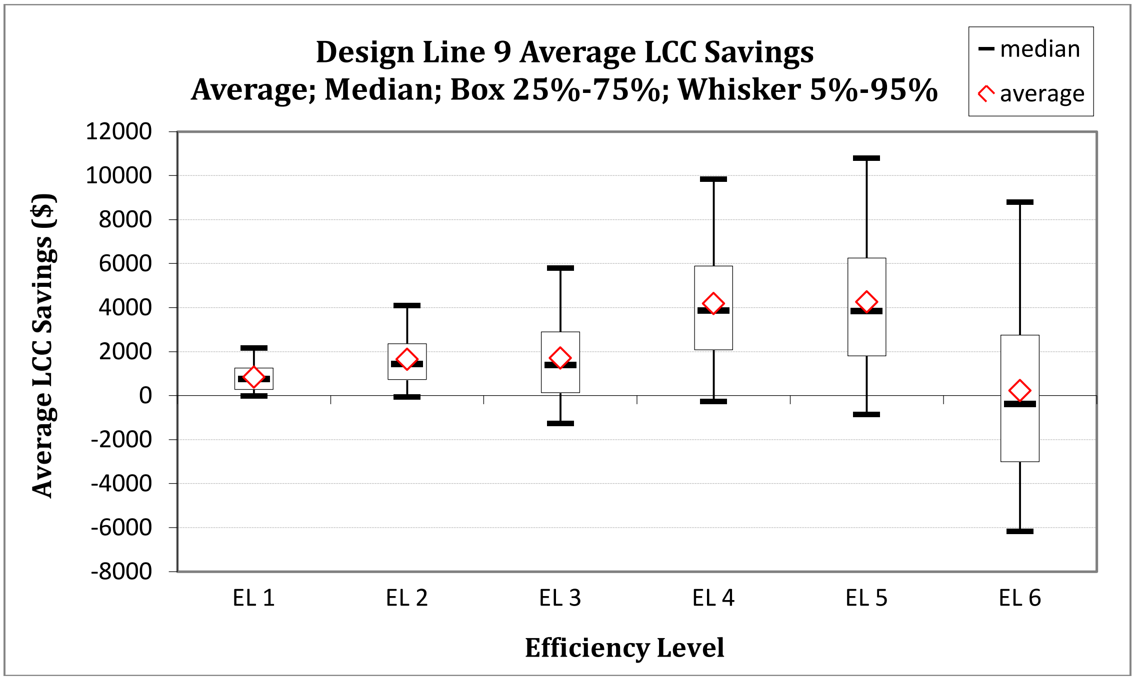

Figure 8C.3.1 Design Line 9, Range of LCC Savings by Efficiency Level

Table 8C.3.1 Summary Life-Cycle Cost Results for Design Line 9 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.93	99.04	99.15	99.22	99.39	99.55
Transformers with Net Increase in LCC (%)	3.35	5.70	22.17	6.00	8.60	53.38
Transformers with Net LCC Savings (%)	83.38	94.30	77.83	94.00	91.40	46.62
Transformers with No Impact on LCC (%)	13.27	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	849	1659	1718	4194	4269	237
Median LCC Savings ($)	763	1447	1407	3885	3841	-365

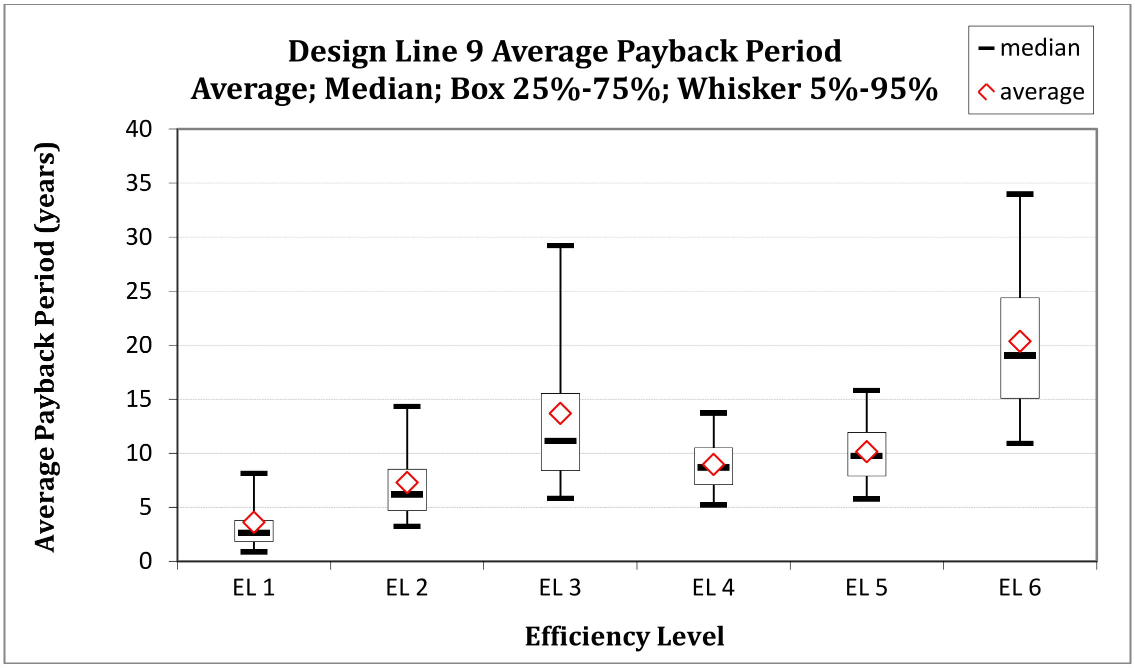

Figure 8C.3.2 Design Line 9, Range of Payback Periods by Efficiency Level

Table 8C.3.2 Summary Payback Period Results for Design Line 9 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	3.6	7.3	13.7	9.0	10.1	20.4
Median Payback (Years)	2.6	6.2	11.1	8.7	9.8	19.1
Transformers having Well Defined Payback (%)	85.45	99.98	99.92	100.00	100.00	100.00
Transformers having Undefined Payback (%)	14.55	0.02	0.08	0.00	0.00	0.00
Mean Rretail Price ($)	14,388	14,994	16,391	17,256	18,027	23,021
Mean Installation Costs ($)	3,295	3,311	3,435	3,674	3,806	4,431
Mean Operating Costs ($)	861	784	699	505	452	367
Mean Incremental First Cost ($)	139	760	2,282	3,386	4,289	9,907
Mean Operating Cost Savings ($)	53	130	216	409	462	547
Payback of Average Transformer	2.6	5.8	10.6	8.3	9.3	18.1

8C.3.5 Design Line 10 Results

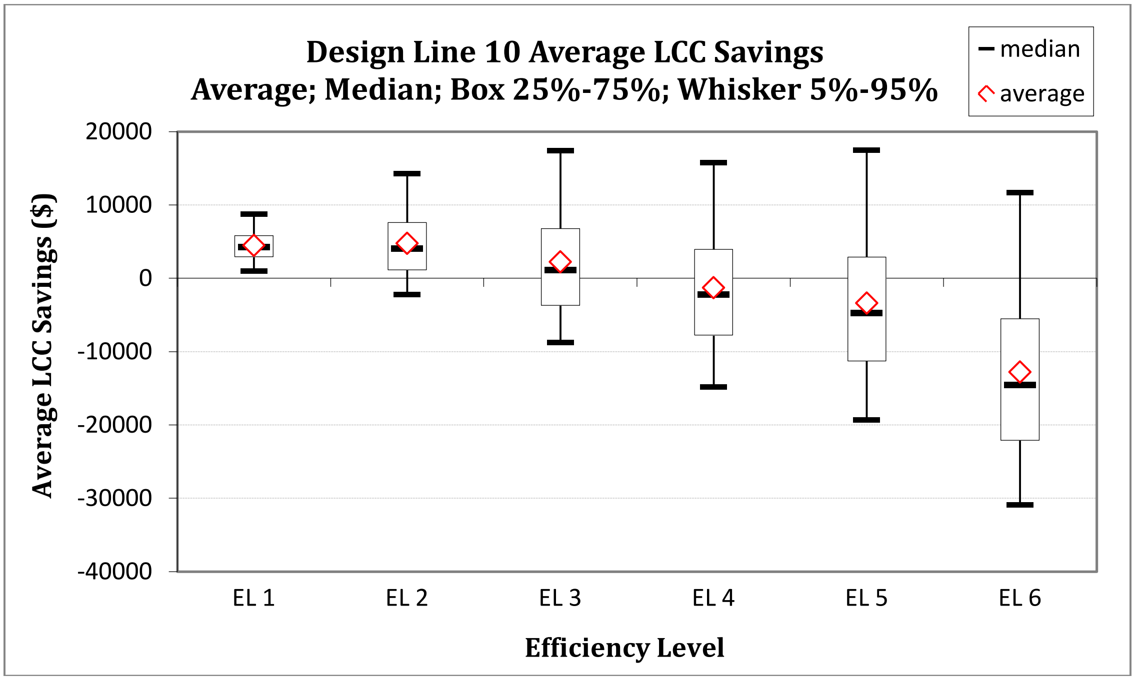

Figure 8C.3.3 Design Line 10, Range of LCC Savings by Efficiency Level

Table 8C.3.3 Summary Life-Cycle Cost Results for Design Line 10 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	99.29	99.37	99.45	99.51	99.58	99.63
Transformers with Net Increase in LCC (%)	0.66	16.72	44.00	60.06	66.77	84.78
Transformers with Net LCC Savings (%)	98.82	83.28	56.00	39.94	33.23	15.22
Transformers with No Impact on LCC (%)	0.52	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	4509	4791	2264	-1259	-3356	-12756
Median LCC Savings ($)	4266	4087	1127	-2228	-4733	-14507

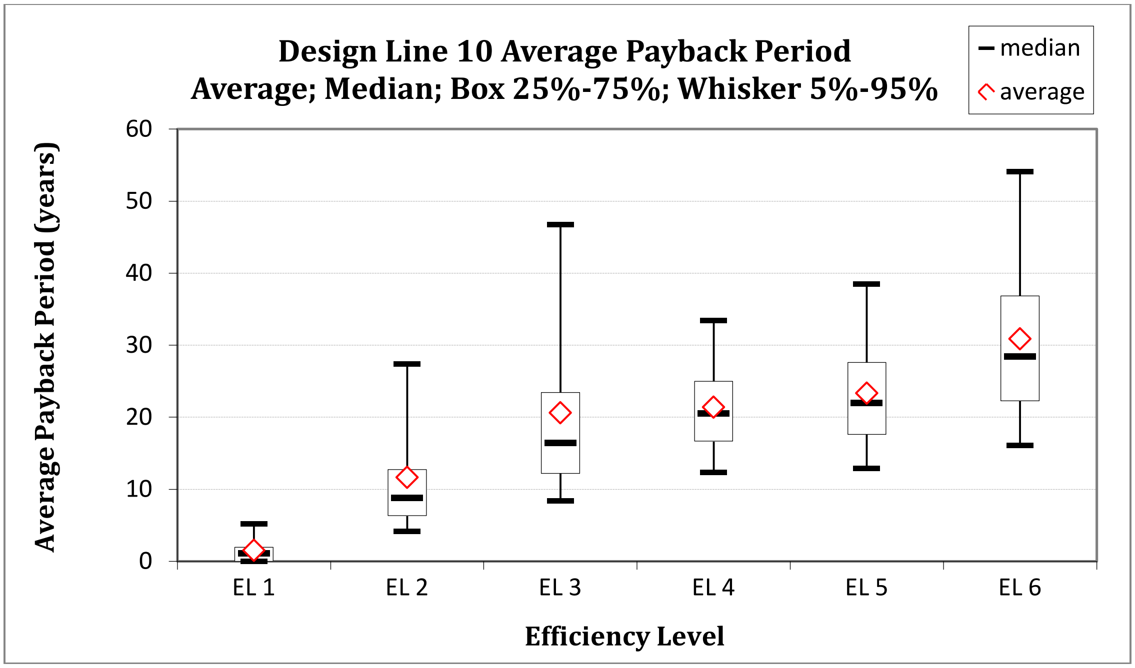

Figure 8C.3.4 Design Line 10, Range of Payback Periods by Efficiency Level

Table 8C.3.4 Summary Payback Period Results for Design Line 10 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	1.5	11.7	20.6	21.4	23.4	30.9
Median Payback (Years)	1.1	8.8	16.4	20.5	22.0	28.4
Transformers having Well Defined Payback (%)	99.45	98.98	99.82	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.55	1.02	0.18	0.00	0.00	0.00
Mean Pretail Price ($)	43,657	46,918	54,571	65,497	70,424	81,370
Mean Installation Costs ($)	6,416	6,834	7,441	8,036	8,390	9,104
Mean Operating Costs ($)	2,550	2,337	2,028	1,596	1,424	1,303
Mean Incremental First Cost ($)	279	3,958	12,218	23,739	29,021	40,680
Mean Operating Cost Savings ($)	258	472	781	1,213	1,384	1,506
Payback of Average Transformer	1.1	8.4	15.6	19.6	21.0	27.0

8C.3.6 Design Line 11 Results

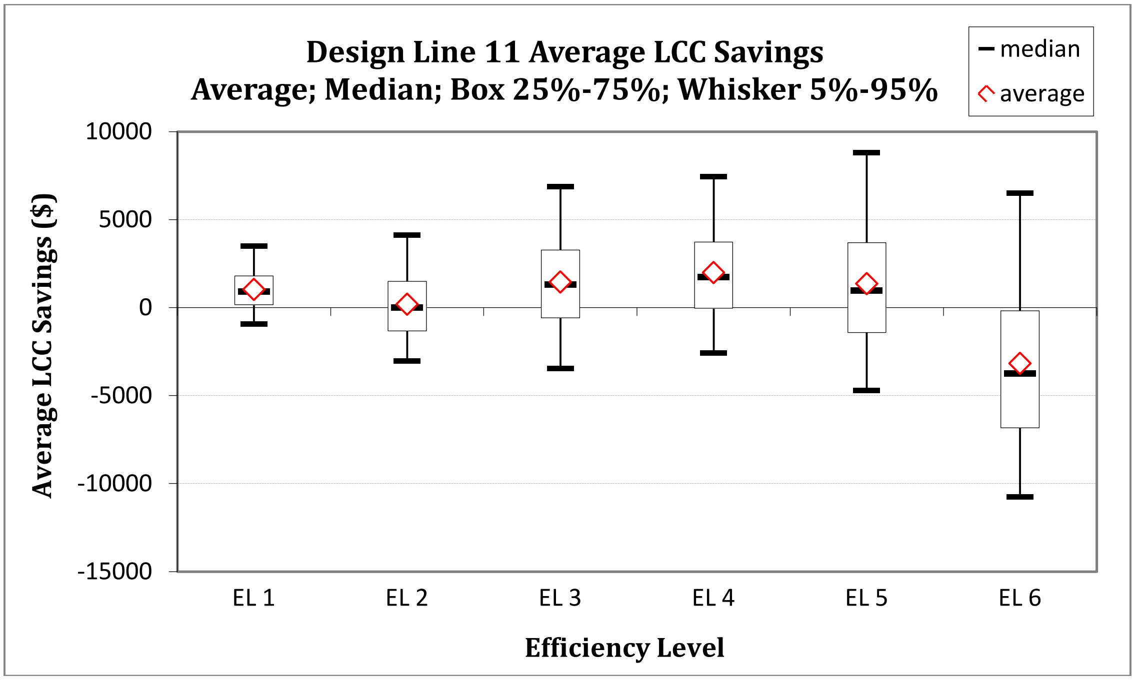

Figure 8C.3.5 Design Line 11, Range of LCC Savings by Efficiency Level

Table 8C.3.5 Summary Life-Cycle Cost Results for Design Line 11 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.81	98.94	99.06	99.13	99.32	99.50
Transformers with Net Increase in LCC (%)	20.61	49.54	32.06	25.66	39.46	76.13
Transformers with Net LCC Savings (%)	79.38	50.46	67.94	74.34	60.54	23.87
Transformers with No Impact on LCC (%)	0.01	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	1043	202	1464	2000	1371	-3160
Median LCC Savings ($)	920	16	1314	1754	984	-3739

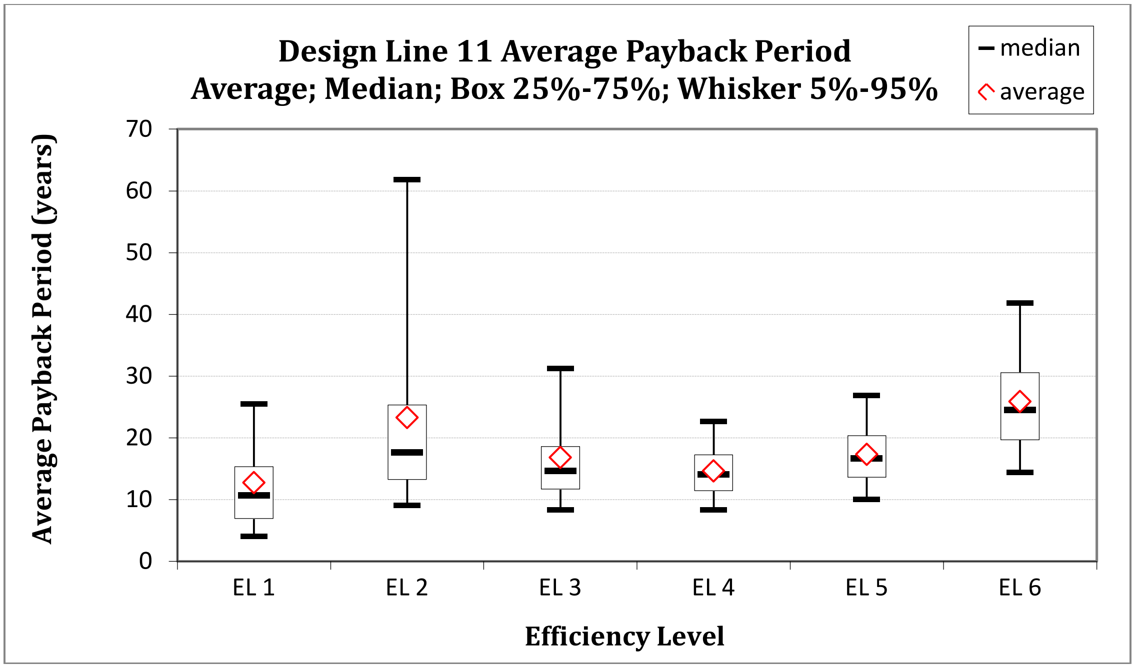

Figure 8C.3.6 Design Line 11, Range of Payback Periods by Efficiency Level

Table 8C.3.6 Summary Payback Period Results for Design Line 11 Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	12.8	23.3	16.8	14.6	17.3	25.9
Median Payback (Years)	10.7	17.6	14.7	14.1	16.6	24.5
Transformers having Well Defined Payback (%)	99.01	98.49	99.98	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.99	1.51	0.02	0.00	0.00	0.00
Mean Pretail Price ($)	22,724	24,638	26,367	26,683	29,377	35,473
Mean Installation Costs ($)	4,030	4,326	4,306	4,296	4,622	5,206
Mean Operating Costs ($)	966	892	731	686	557	441
Mean Incremental First Cost ($)	1,342	3,553	5,261	5,568	8,587	15,267
Mean Operating Cost Savings ($)	129	203	363	408	537	653
Payback of Average Transformer	10.4	17.5	14.5	13.6	16.0	23.4

8C.3.7 Design Line 12 Results

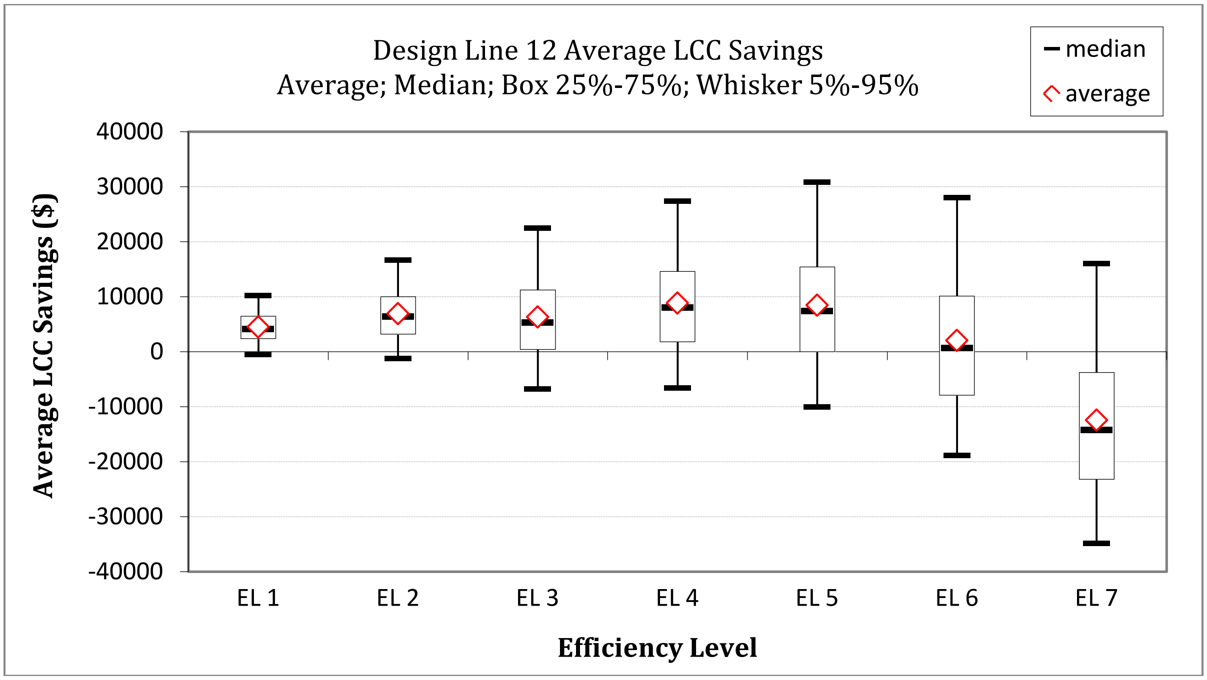

Figure 8C.3.7 Design Line 12, Range of LCC Savings by Efficiency Level

Table 8C.3.7 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Efficiency (%)	99.21	99.30	99.39	99.46	99.53	99.59	99.63
Transformers with Net Increase in LCC (%)	6.72	7.76	23.46	18.12	25.10	48.09	81.09
Transformers with No Impact on LCC (%)	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Transformers with Net LCC Savings (%)	93.27	92.24	76.54	81.88	74.90	51.91	18.91
Mean LCC Savings ($)	4518	6934	6332	8860	8475	2063	-12420
Median LCC Savings ($)	4178	6402	5356	8003	7400	642	-14191

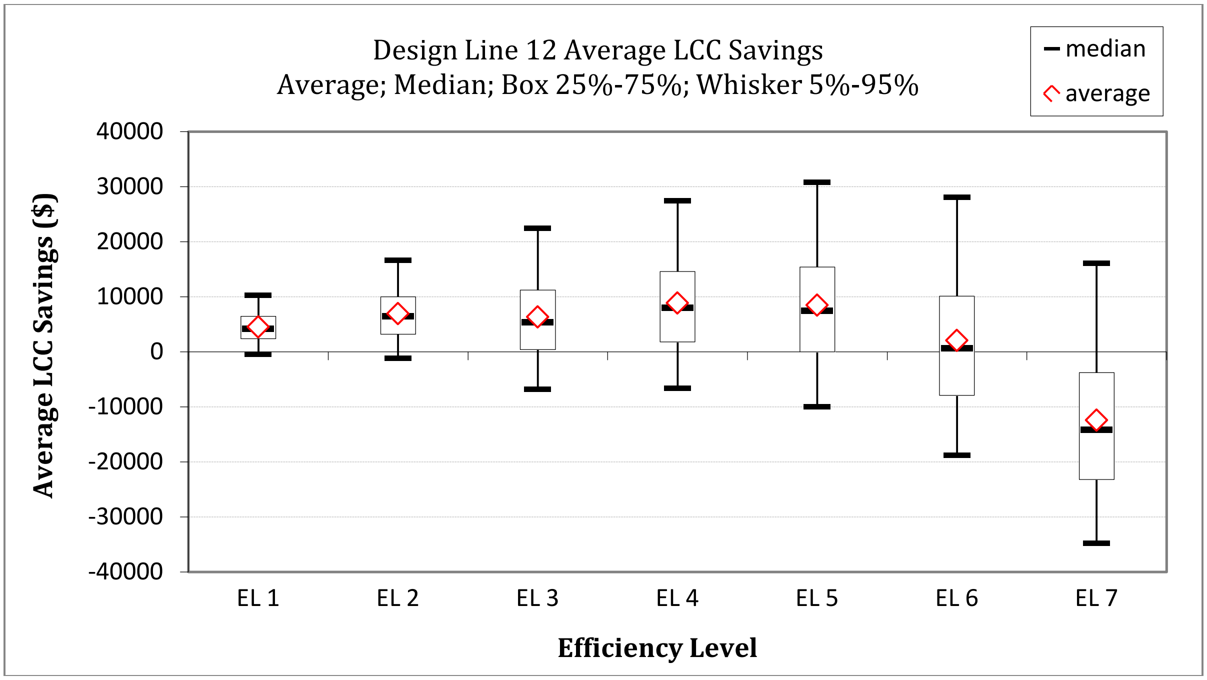

Figure 8C.3.8 Design Line 12, Range of Payback Periods by Efficiency Level

Table 8C.3.8 Summary Payback Period Results for Design Line 12 Representative Unit

	Efficiency Level						
	1	**2**	**3**	**4**	**5**	**6**	**7**
Mean Payback (Years)	7.5	9.6	14.4	13.3	14.6	19.0	27.1
Median Payback (Years)	6.3	9.0	13.5	13.0	14.1	18.2	25.9
Transformers having Well Defined Payback (%)	99.29	100.00	99.99	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	0.71	0.00	0.01	0.00	0.00	0.00	0.00
Mean Pretail Price ($)	57,380	60,978	68,566	71,895	76,909	86,085	101,590
Mean Installation Costs ($)	7,113	7,231	7,971	8,316	8,637	9,318	10,270
Mean Operating Costs ($)	2,976	2,645	2,228	1,894	1,627	1,441	1,335
Mean Incremental First Cost ($)	2,326	6,042	14,370	18,045	23,379	33,236	49,694
Mean Operating Cost Savings ($)	370	701	1,118	1,452	1,719	1,905	2,011
Payback of Average Transformer	6.3	8.6	12.9	12.4	13.6	17.4	24.7

8C.3.8 Design Line 13A Results

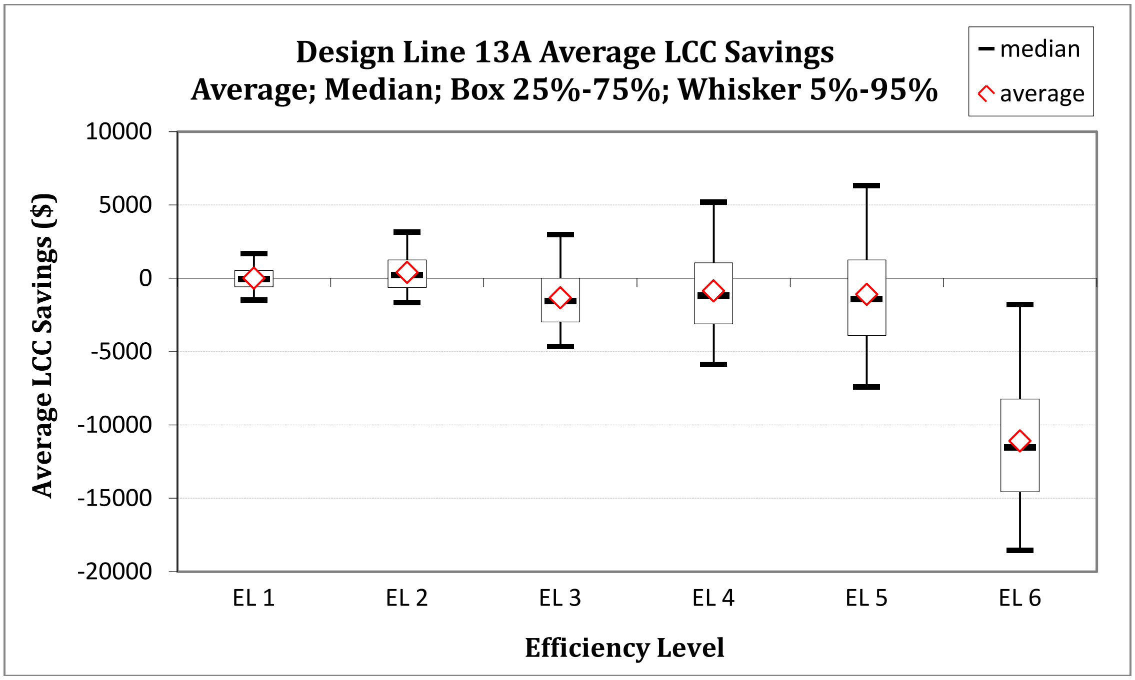

Figure 8C.3.9 Design Line 13A, Range of LCC Savings by Efficiency Level

Table 8C.3.9 Summary Life-Cycle Cost Results for Design Line 13A Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Efficiency (%)	98.69	98.84	98.97	99.04	99.25	99.45
Transformers with Net Increase in LCC (%)	52.17	43.00	74.81	64.38	64.41	97.08
Transformers with Net LCC Savings (%)	47.81	57.00	25.19	35.62	35.59	2.92
Transformers with No Impact on LCC (%)	0.02	0.00	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	25	414	-1318	-846	-1084	-11077
Median LCC Savings ($)	-43	224	-1543	-1153	-1392	-11526

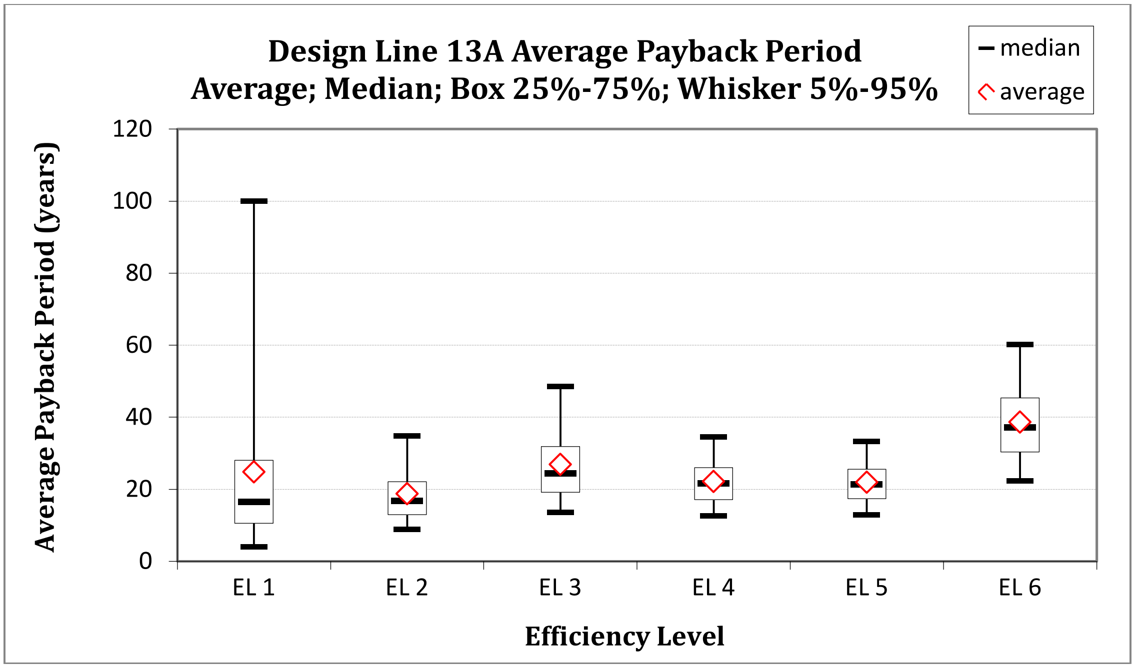

Figure 8C.3.10 Design Line 13A, Range of Payback Periods by Efficiency Level

Table 8C.3.10 Summary Payback Period Results for Design Line 13A Representative Unit

	Efficiency Level					
	1	**2**	**3**	**4**	**5**	**6**
Mean Payback (Years)	24.8	18.8	26.9	22.2	22.0	38.7
Median Payback (Years)	16.5	16.8	24.4	21.7	21.3	37.1
Transformers having Well Defined Payback (%)	88.59	99.93	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	11.41	0.07	0.00	0.00	0.00	0.00
Mean Pretail Price ($)	27,902	29,552	32,891	35,577	37,918	48,703
Mean Installation Costs ($)	4,752	4,832	5,103	5,093	5,309	6,280
Mean Operating Costs ($)	1,082	967	866	696	571	476
Mean Incremental First Cost ($)	868	2,598	6,207	8,884	11,441	23,197
Mean Operating Cost Savings ($)	48	162	264	434	559	654
Payback of Average Transformer	18.0	16.0	23.5	20.5	20.5	35.5

8C.3.9 Design Line 13B Results

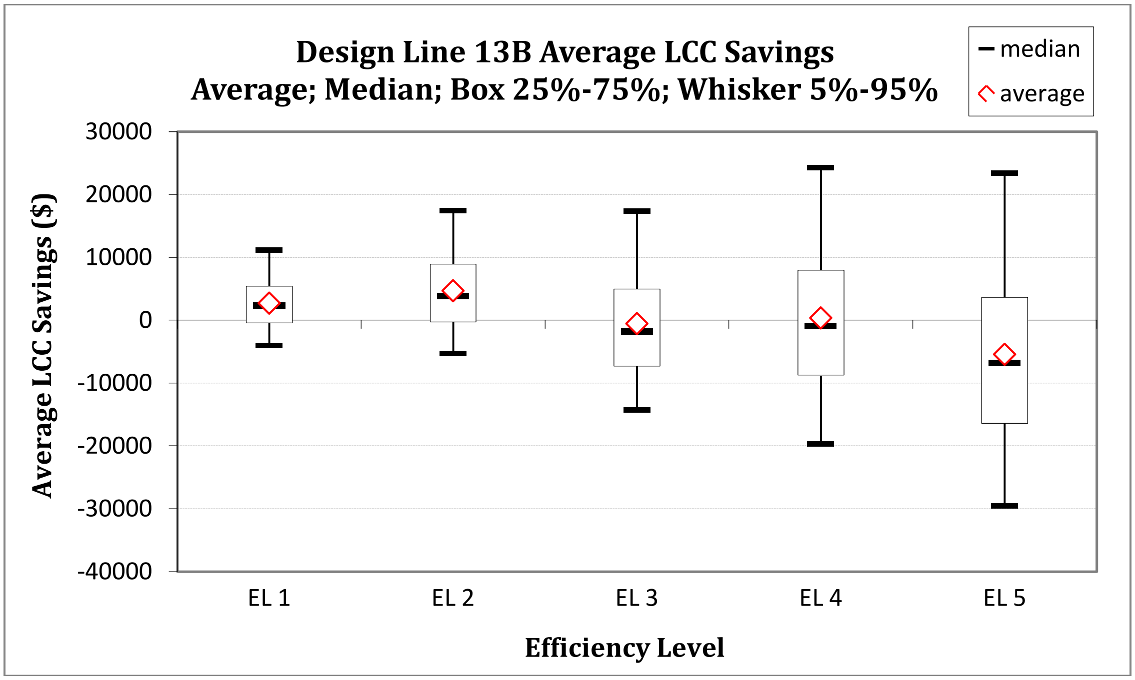

Figure 8C.3.11 Design Line 13B, Range of LCC Savings by Efficiency Level

Table 8C.3.11 Summary Life-Cycle Cost Results for Design Line 13B Representative Unit

	Efficiency Level				
	1	**2**	**3**	**4**	**5**
Efficiency (%)	99.19	99.28	99.38	99.45	99.52
Transformers with Net Increase in LCC (%)	28.50	26.34	57.60	52.74	67.20
Transformers with Net LCC Savings (%)	71.30	73.66	42.40	47.26	32.80
Transformers with No Impact on LCC (%)	0.20	0.00	0.00	0.00	0.00
Mean LCC Savings ($)	2733	4709	-520	384	-5407
Median LCC Savings ($)	2361	3899	-1807	-923	-6757

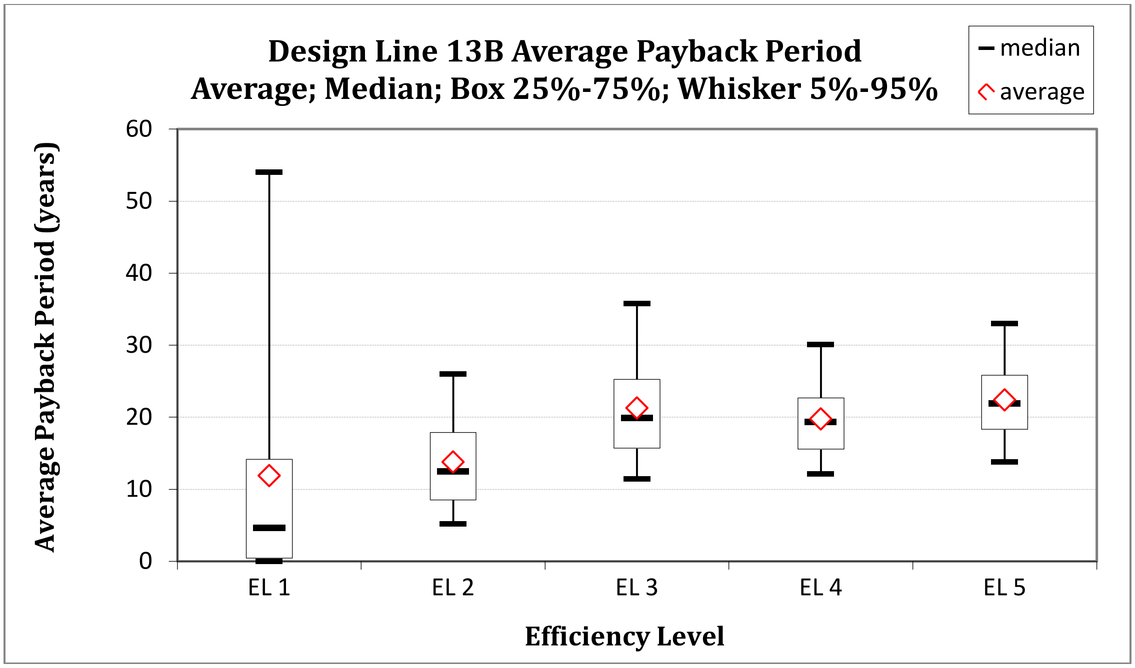

Figure 8C.3.12 Design Line 13B, Range of Payback Periods by Efficiency Level

Table 8C.3.12 Summary Payback Period Results for Design Line 13B Representative Unit

	Efficiency Level				
	1	**2**	**3**	**4**	**5**
Mean Payback (Years)	11.9	13.8	21.3	19.8	22.4
Median Payback (Years)	4.6	12.5	19.9	19.3	21.9
Transformers having Well Defined Payback (%)	88.05	100.00	100.00	100.00	100.00
Transformers having Undefined Payback (%)	11.95	0.00	0.00	0.00	0.00
Mean Pretail Price ($)	72,108	80,007	91,898	103,613	116,322
Mean Installation Costs ($)	8,958	8,997	9,629	9,652	10,305
Mean Operating Costs ($)	4,082	3,547	3,154	2,471	2,063
Mean Incremental First Cost ($)	1,398	9,337	21,859	33,599	46,959
Mean Operating Cost Savings ($)	223	758	1,151	1,834	2,242
Payback of Average Transformer	6.3	12.3	19.0	18.3	20.9

APPENDIX 8D. LIFE-CYCLE COST SENSITIVITY ANALYSIS

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APPENDIX 8D. LIFE-CYCLE COST SENSITIVITY ANALYSIS

8D.1 DESIGN LINE 1 RESULTS

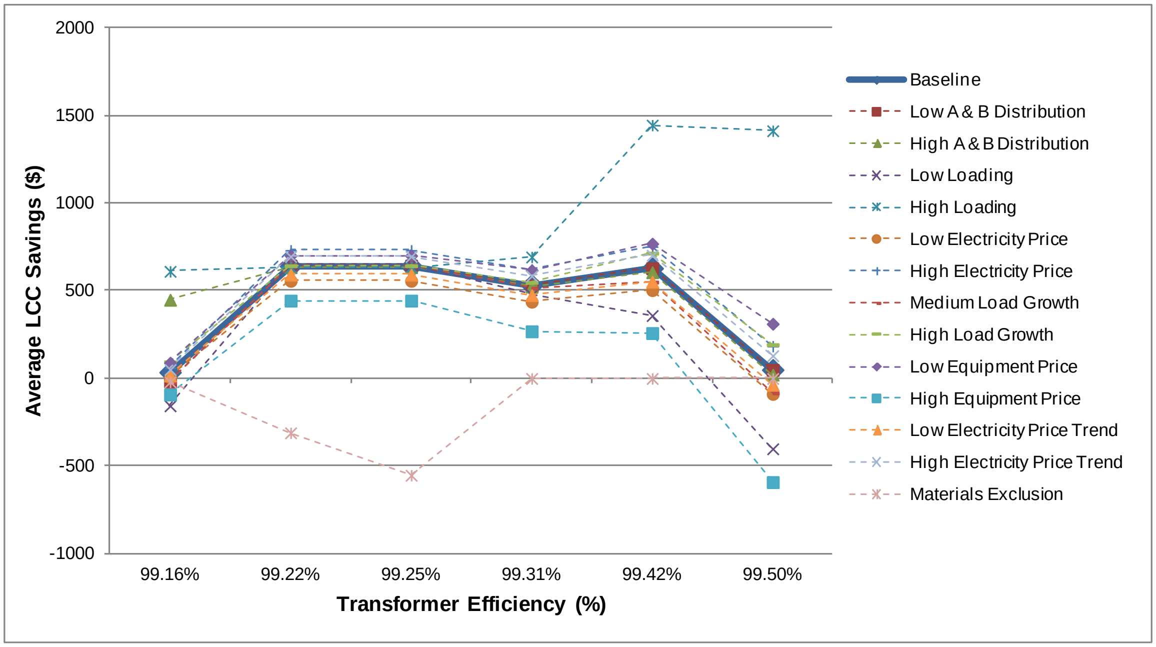

Figure 8D.1.1 Average LCC Savings ($) by Scenario for Design Line 1

Table 8D.1.1 LCC Savings ($), Summary Table for Design Line 1

Scenario	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Baseline	36	641	641	532	629	50
Low A & B Distribution	-17	643	643	530	629	49
High A & B Distribution	449	635	635	524	606	22
Low Loading	-156	647	647	477	359	-401
High Loading	611	633	633	693	1445	1413
Low Electricity Price	6	557	557	438	504	-88
High Electricity Price	61	731	731	622	752	184
No Load Growth	-21	645	645	515	550	-82
High Load Growth	95	643	643	548	715	193
Low Equipment Price	90	701	701	617	769	312
High Equipment Price	-91	444	444	269	259	-591
Low Electricity Price Trend	17	592	592	475	552	-36
High Electricity Price Trend	51	696	696	585	703	130
Materials Exclusion	-19	-310	-552	NA	NA	NA

8D.1.1 Design Line 1 Results, Baseline Scenario

Table 8D.1.2 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Baseline Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	57.94%	4.77%	4.77%	8.00%	13.63%	55.36%
Transformers with No Change in LCC (%)	0.23%	0.23%	0.23%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	41.83%	95.00%	95.00%	92.00%	86.37%	44.64%
Mean LCC Savings ($)	36	641	641	532	629	50
Median LCC Savings ($)	-64	650	650	540	563	-104

Table 8D.1.3 Summary Payback Period Results for Design Line 1 Representative Unit, Baseline Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	32.2	8.2	8.2	10.4	12.0	19.9
Median Payback (Years)	20.2	7.9	7.9	10.0	11.5	19.2
Transformers having Well Defined Payback (%)	85.02%	99.77%	99.77%	99.89%	99.99%	99.95%
Transformers having Undefined Payback (%)	14.98%	0.23%	0.23%	0.11%	0.01%	0.05%
Mean Retail Cost ($)	2,244	2,446	2,446	2,549	2,802	3,333
Mean Installation Cost ($)	2,230	2,271	2,271	2,344	2,415	2,606
Mean Operating Costs ($)	209	156	156	153	132	126
Mean Incremental First Cost ($)	327	569	569	746	1,070	1,792
Mean Operating Cost Savings ($)	18	71	71	74	95	100
Payback of Average Transformer	18.2	8.0	8.0	10.1	11.2	17.8

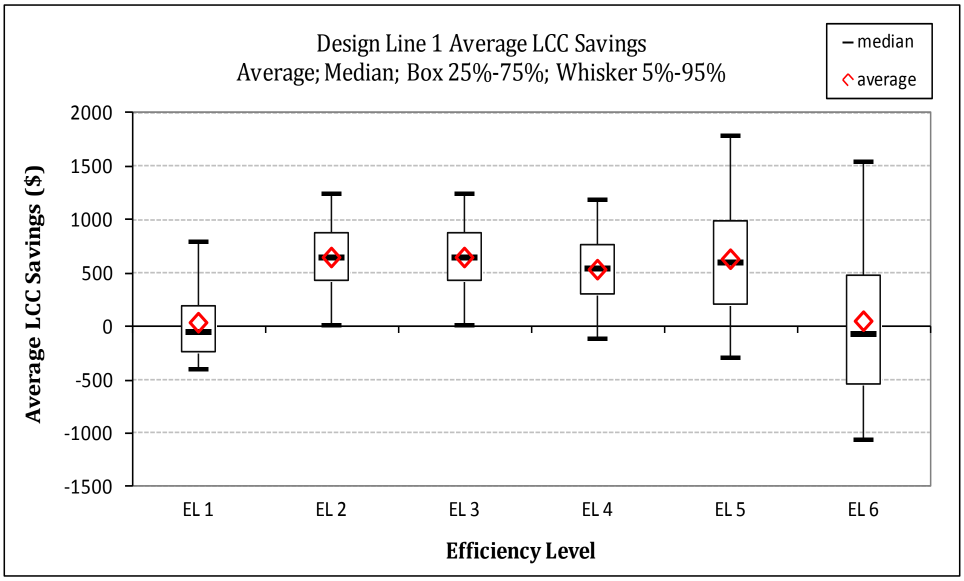

Figure 8D.1.2 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Baseline Scenario

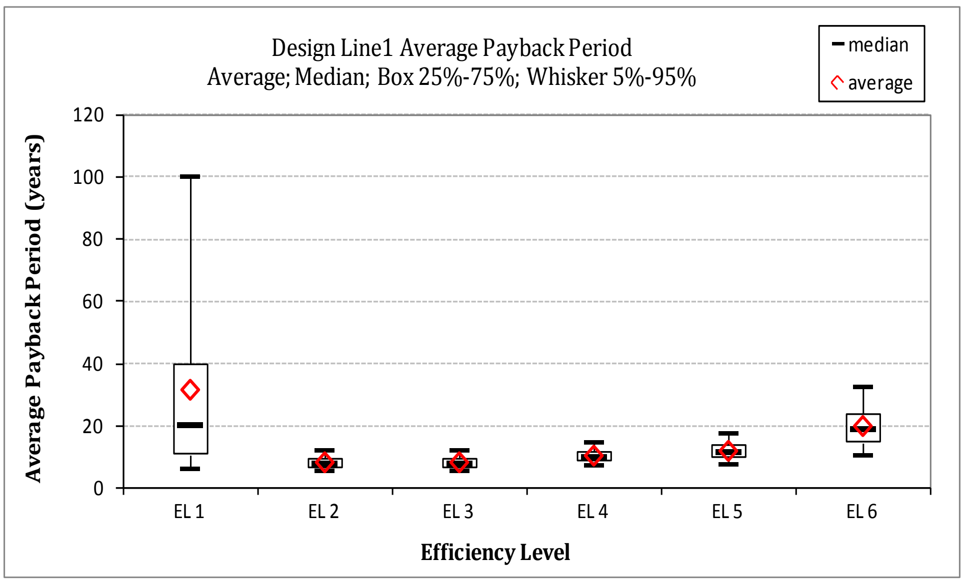

Figure 8D.1.3 Average Payback Period for Design Line 1 Representative Unit, Baseline Scenario

8D.1.2 Design Line 1 Results, Low A & B Distribution Scenario

Table 8D.1.4 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Low A & B Distribution Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	63.00%	4.50%	4.50%	8.10%	13.40%	54.30%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	37.00%	95.50%	95.50%	91.90%	86.60%	45.70%
Mean LCC Savings ($)	-17	643	643	530	629	49
Median LCC Savings ($)	-82	647	647	540	596	-71

Table 8D.1.5 Summary Payback Period Results for Design Line 1 Representative Unit, Low A & B Distribution Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	34.1	8.3	8.3	10.4	11.9	19.9
Median Payback (Years)	22.3	7.9	7.9	10.0	11.5	18.9
Transformers having Well Defined Payback (%)	83.80%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	16.20%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	2,228	2,444	2,444	2,547	2,800	3,330
Mean Installation Cost ($)	2,227	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	213	155	155	153	132	126
Mean Incremental First Cost ($)	313	574	574	751	1,073	1,795
Mean Operating Cost Savings ($)	14	71	71	74	95	101
Payback of Average Transformer	22.5	8.0	8.0	10.1	11.3	17.9

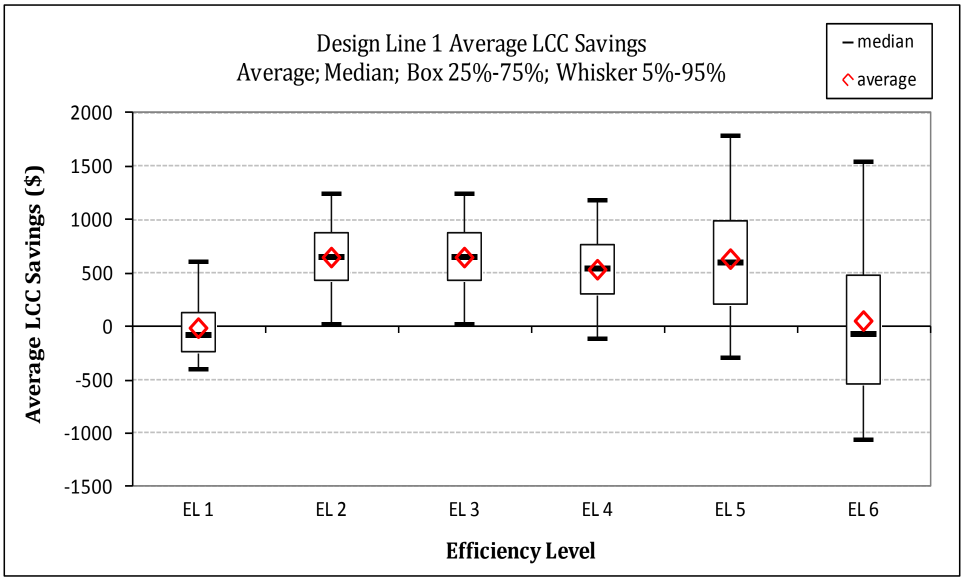

Figure 8D.1.4 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Low A & B Distribution Scenario

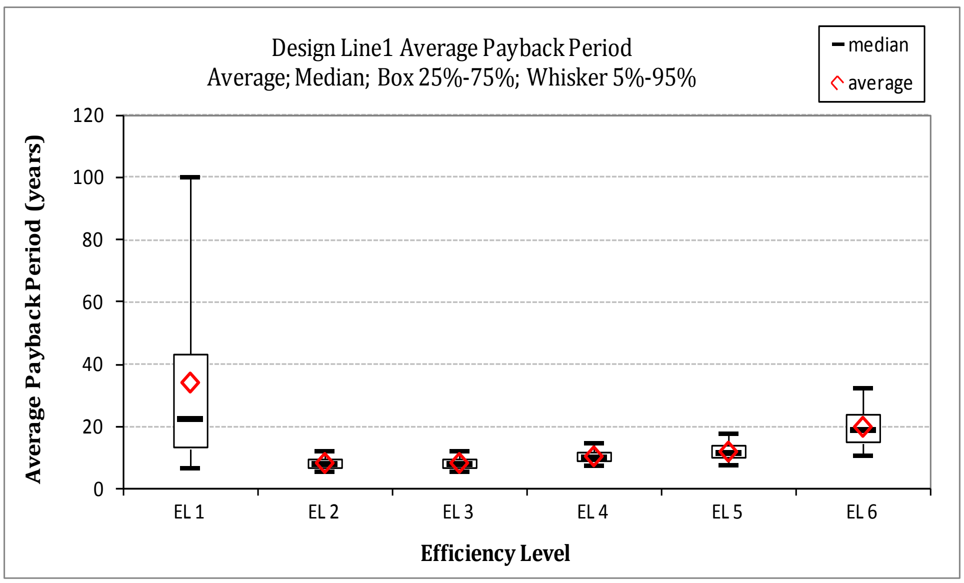

Figure 8D.1.5 Average Payback Period for Design Line 1 Representative Unit, Low A & B Distribution Scenario

8D.1.3 Design Line 1 Results, High A & B Distribution Scenario

Table 8D.1.6 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, High A & B Distribution Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	23.20%	4.30%	4.30%	10.30%	15.40%	56.00%
Transformers with No Change in LCC (%)	3.00%	3.00%	3.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	73.80%	92.70%	92.70%	89.70%	84.60%	44.00%
Mean LCC Savings ($)	449	635	635	524	606	22
Median LCC Savings ($)	485	652	652	537	566	-104

Table 8D.1.7 Summary Payback Period Results for Design Line 1 Representative Unit, High A & B Distribution Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	16.0	8.2	8.2	11.3	12.6	20.8
Median Payback (Years)	8.1	7.8	7.8	10.0	11.6	19.4
Transformers having Well Defined Payback (%)	93.30%	97.00%	97.00%	99.10%	99.90%	99.50%
Transformers having Undefined Payback (%)	6.70%	3.00%	3.00%	0.90%	0.10%	0.50%
Mean Retail Cost ($)	2,350	2,444	2,444	2,552	2,797	3,331
Mean Installation Cost ($)	2,254	2,267	2,267	2,343	2,414	2,606
Mean Operating Costs ($)	173	154	154	151	131	126
Mean Incremental First Cost ($)	442	549	549	733	1,049	1,775
Mean Operating Cost Savings ($)	51	69	69	73	92	98
Payback of Average Transformer	8.7	7.9	7.9	10.1	11.4	18.2

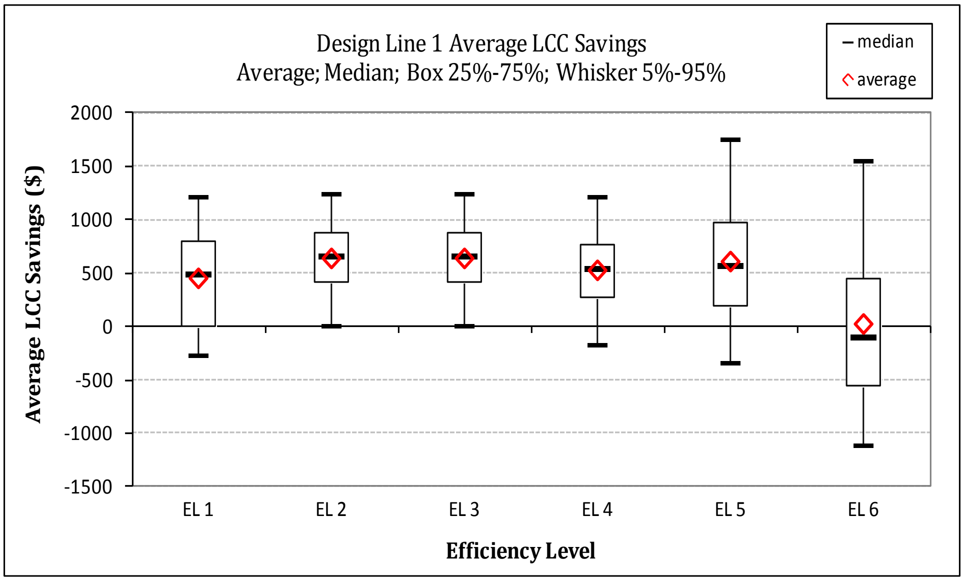

Figure 8D.1.6 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, High A & B Distribution Scenario

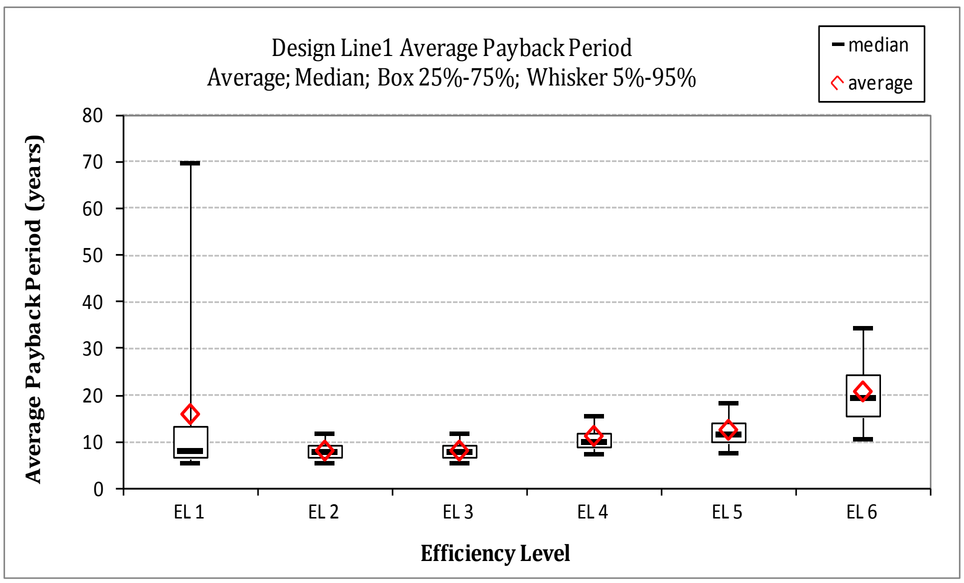

Figure 8D.1.7 Average Payback Period for Design Line 1 Representative Unit, High A & B Distribution Scenario

8D.1.4 Design Line 1 Results, Low Loading Scenario

Table 8D.1.8 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Low Loading Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	82.40%	4.60%	4.60%	8.70%	20.90%	80.10%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	17.50%	95.30%	95.30%	91.30%	79.10%	19.90%
Mean LCC Savings ($)	-156	647	647	477	359	-401
Median LCC Savings ($)	-231	646	646	491	364	-451

Table 8D.1.9 Summary Payback Period Results for Design Line 1 Representative Unit, Low Loading Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	46.8	8.3	8.3	10.8	13.8	25.0
Median Payback (Years)	34.6	7.9	7.9	10.3	13.2	24.2
Transformers having Well Defined Payback (%)	63.20%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	36.80%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	178	115	115	115	105	109
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	8	72	72	71	81	77
Payback of Average Transformer	40.3	8.0	8.0	10.5	13.2	23.2

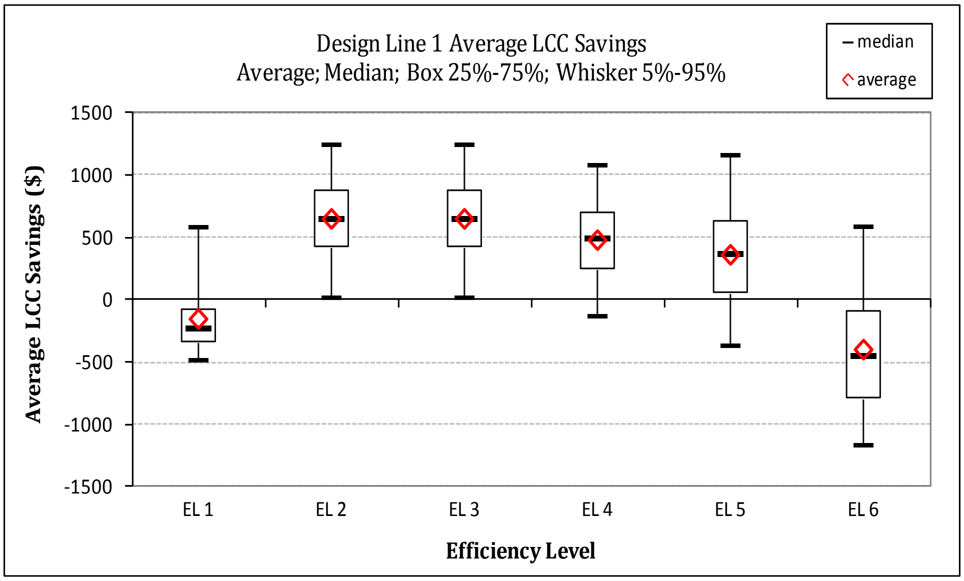

Figure 8D.1.8 **Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Low Loading Scenario**

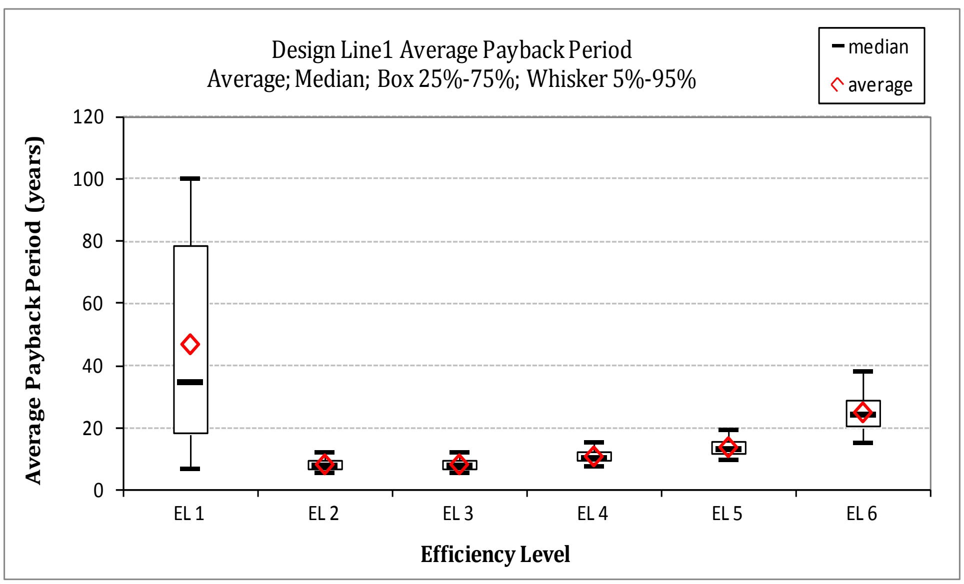

Figure 8D.1.9 **Average Payback Period for Design Line 1 Representative Unit, Low Loading Scenario**

8D.1.5 Design Line 1 Results, High Loading Scenario

Table 8D.1.10 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, High Loading Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	19.40%	5.30%	5.30%	6.00%	5.90%	19.80%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	80.50%	94.60%	94.60%	94.00%	94.10%	80.20%
Mean LCC Savings ($)	611	633	633	693	1445	1413
Median LCC Savings ($)	450	628	628	678	1267	1053

Table 8D.1.11 Summary Payback Period Results for Design Line 1 Representative Unit, High Loading Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	13.0	8.4	8.4	9.5	8.7	12.7
Median Payback (Years)	7.9	8.0	8.0	9.1	8.3	11.6
Transformers having Well Defined Payback (%)	98.00%	99.90%	99.90%	100%	100%	100%
Transformers having Undefined Payback (%)	2.00%	0.10%	0.10%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	302	279	279	267	213	179
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	48	71	71	83	137	171
Payback of Average Transformer	6.9	8.1	8.1	9.1	7.8	10.5

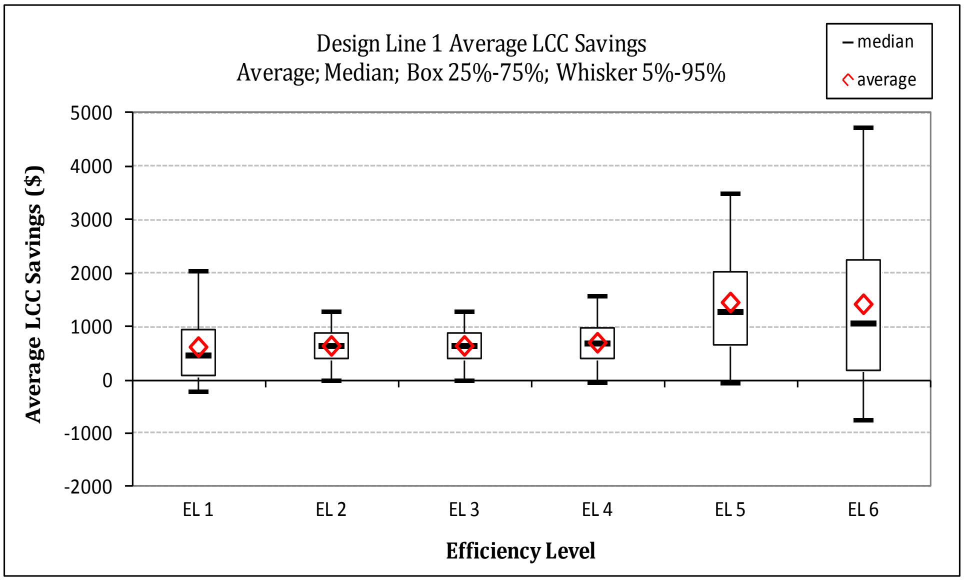

Figure 8D.1.10 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, High Loading Scenario

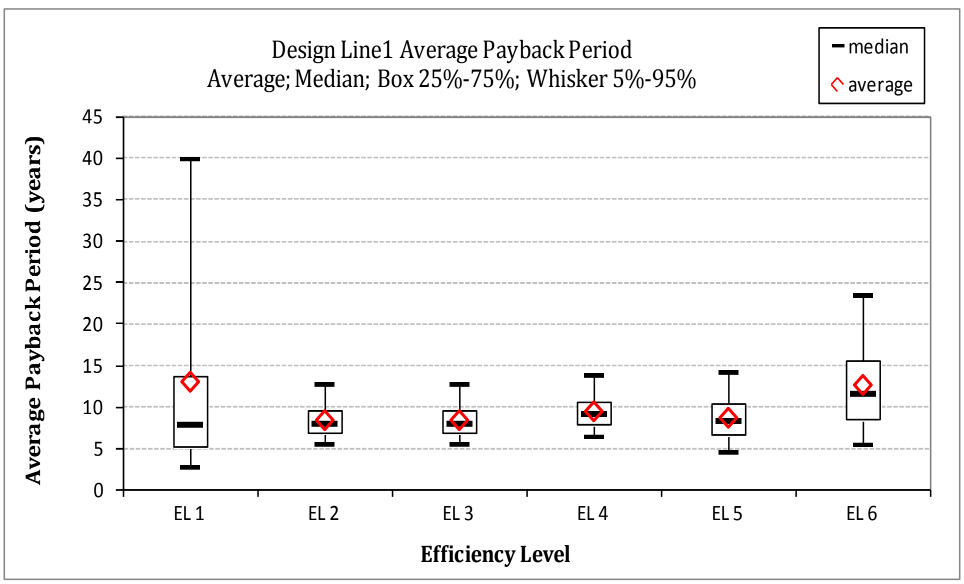

Figure 8D.1.11 Average Payback Period for Design Line 1 Representative Unit, High Loading Scenario

8D.1.6 Design Line 1 Results, Low Electricity Price Scenario

Table 8D.1.12 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Low Electricity Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	61.60%	6.10%	6.10%	10.60%	18.30%	63.20%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	38.30%	93.80%	93.80%	89.40%	81.70%	36.80%
Mean LCC Savings ($)	6	557	557	438	504	-88
Median LCC Savings ($)	-81	565	565	453	468	-209

Table 8D.1.13 Summary Payback Period Results for Design Line 1 Representative Unit, Low Electricity Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	33.3	8.9	8.9	11.2	12.9	21.6
Median Payback (Years)	21.6	8.5	8.5	10.8	12.4	20.7
Transformers having Well Defined Payback (%)	83.20%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	16.80%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	195	145	145	142	123	118
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	17	66	66	69	88	93
Payback of Average Transformer	19.8	8.6	8.6	10.9	12.2	19.3

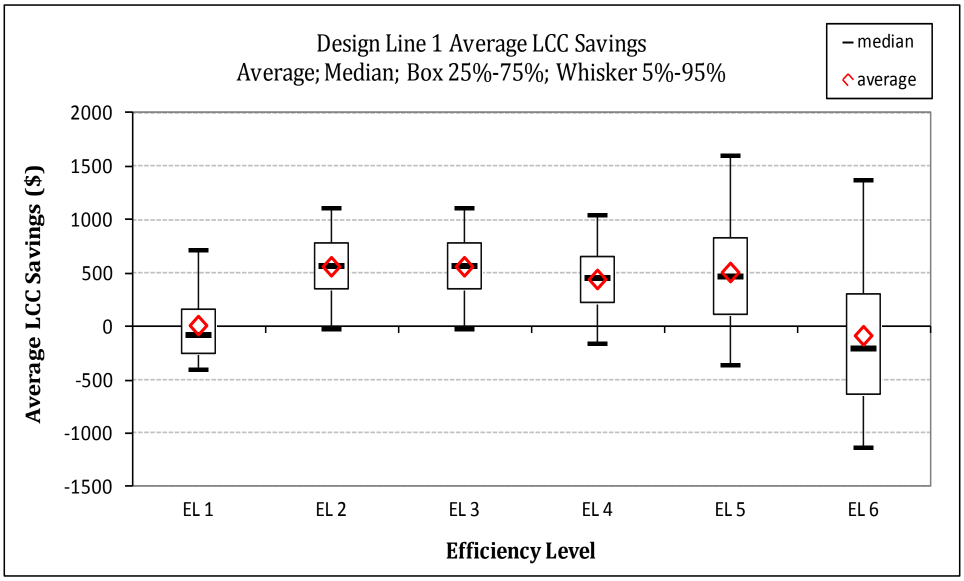

Figure 8D.1.12 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Low Electricity Price Scenario

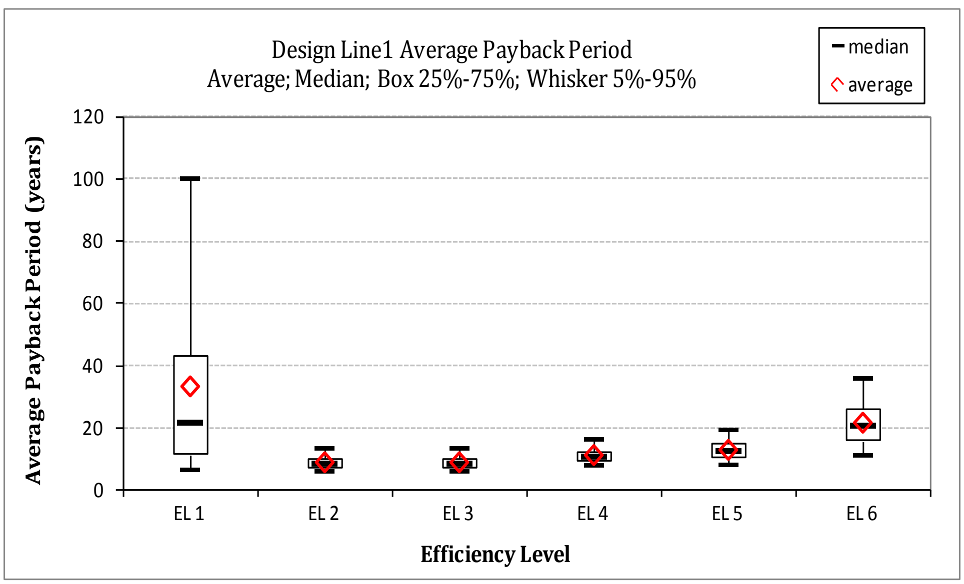

Figure 8D.1.13 Average Payback Period for Design Line 1 Representative Unit, Low Electricity Price Scenario

8D.1.7 Design Line 1 Results, High Electricity Price Scenario

Table 8D.1.14 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, High Electricity Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	54.30%	4.00%	4.00%	5.90%	10.10%	45.80%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	45.60%	95.90%	95.90%	94.10%	89.90%	54.20%
Mean LCC Savings ($)	61	731	731	622	752	184
Median LCC Savings ($)	-35	722	722	630	715	69

Table 8D.1.15 Summary Payback Period Results for Design Line 1 Representative Unit, High Electricity Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	29.7	7.7	7.7	9.7	11.1	18.5
Median Payback (Years)	18.8	7.4	7.4	9.3	10.7	17.6
Transformers having Well Defined Payback (%)	85.30%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	14.70%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	223	166	166	163	140	134
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	19	76	76	80	102	108
Payback of Average Transformer	17.0	7.5	7.5	9.4	10.5	16.6

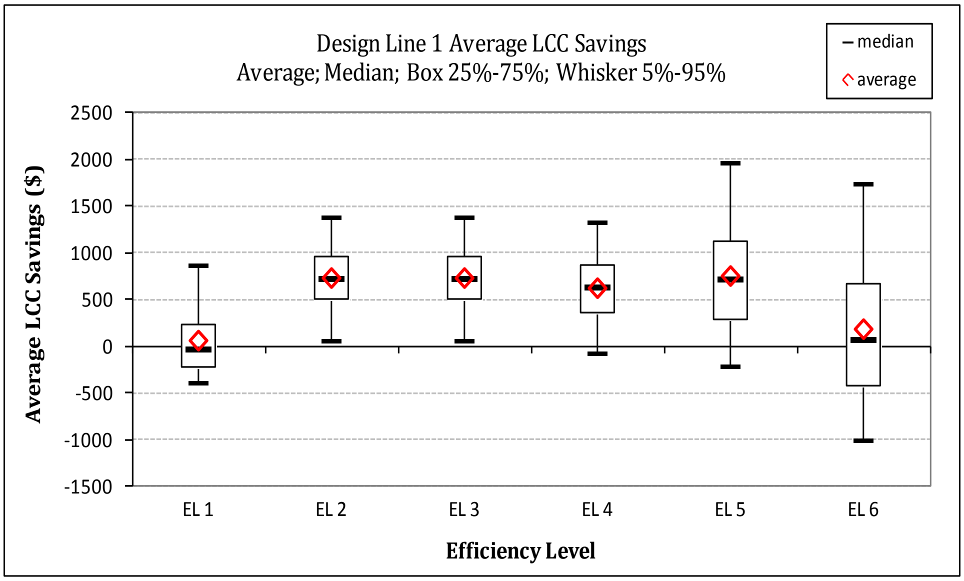

Figure 8D.1.14 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, High Electricity Price Scenario

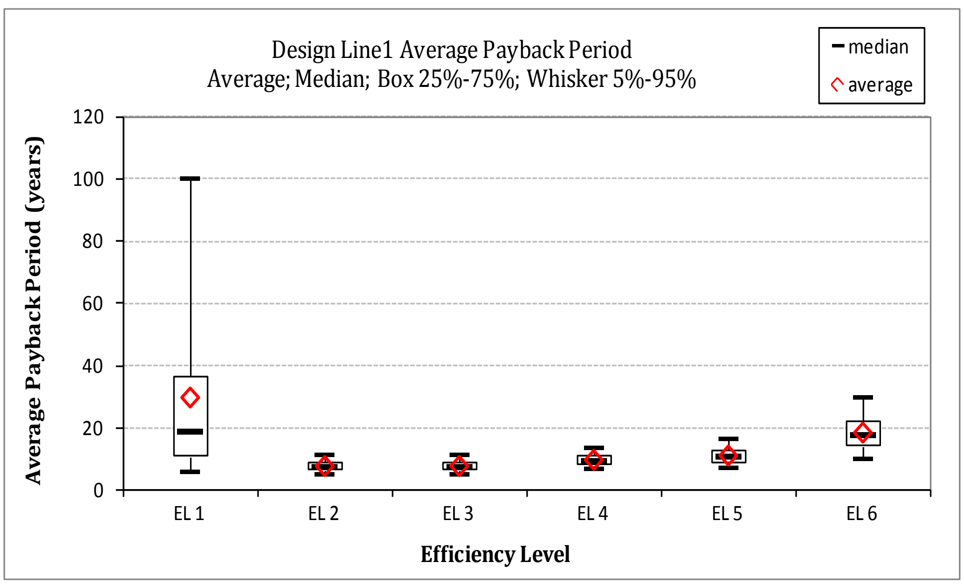

Figure 8D.1.15 Average Payback Period for Design Line 1 Representative Unit, High Electricity Price Scenario

8D.1.8 Design Line 1 Results, No Load Growth Scenario

Table 8D.1.16 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, No Load Growth Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	64.80%	4.50%	4.50%	8.30%	15.10%	61.50%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	35.10%	95.40%	95.40%	91.70%	84.90%	38.50%
Mean LCC Savings ($)	-21	645	645	515	550	-82
Median LCC Savings ($)	-104	646	646	528	532	-175

Table 8D.1.17 Summary Payback Period Results for Design Line 1 Representative Unit, No Load Growth Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	31.6	8.3	8.3	10.4	11.9	19.9
Median Payback (Years)	20.2	7.9	7.9	10.0	11.5	19.0
Transformers having Well Defined Payback (%)	84.50%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	15.50%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	209	155	155	152	132	126
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	18	71	71	74	95	100
Payback of Average Transformer	18.3	8.0	8.0	10.1	11.3	17.9

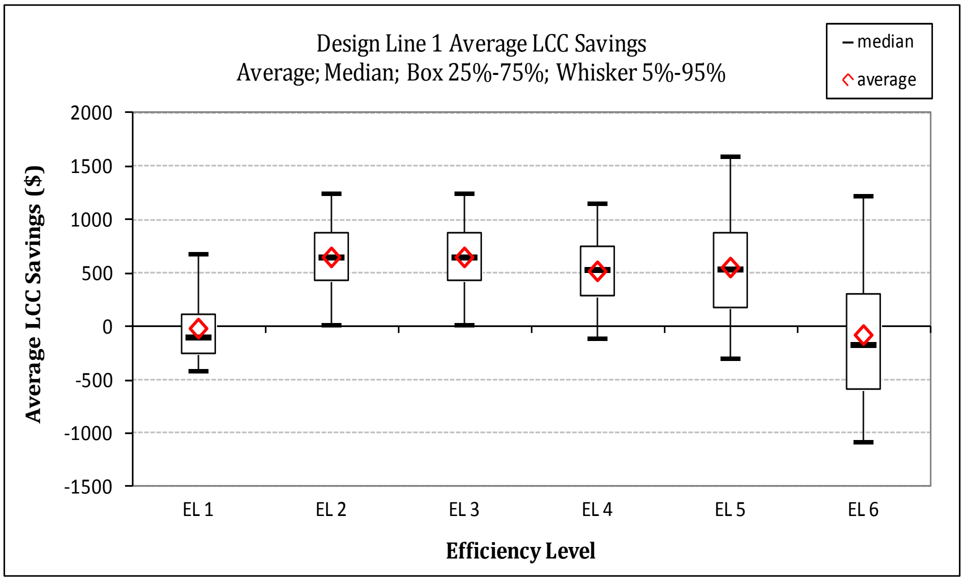

Figure 8D.1.16 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, No Load Growth Scenario

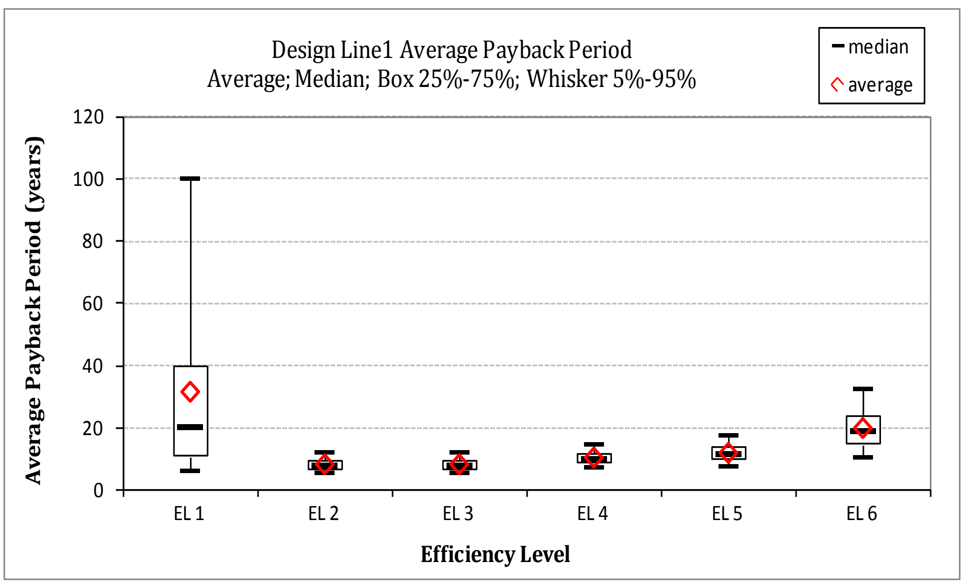

Figure 8D.1.17 Average Payback Period for Design Line 1 Representative Unit, No Load Growth Scenario

8D.1.9 Design Line 1 Results, High Load Growth Scenario

Table 8D.1.18 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, High Load Growth Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	49.90%	4.50%	4.50%	8.00%	12.60%	47.10%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	50.00%	95.40%	95.40%	92.00%	87.40%	52.90%
Mean LCC Savings ($)	95	643	643	548	715	193
Median LCC Savings ($)	0	644	644	556	658	49

Table 8D.1.19 Summary Payback Period Results for Design Line 1 Representative Unit, High Load Growth Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	31.6	8.3	8.3	10.4	11.9	19.9
Median Payback (Years)	20.2	7.9	7.9	10.0	11.5	19.0
Transformers having Well Defined Payback (%)	84.50%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	15.50%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	209	155	155	152	132	126
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	18	71	71	74	95	100
Payback of Average Transformer	18.3	8.0	8.0	10.1	11.3	17.9

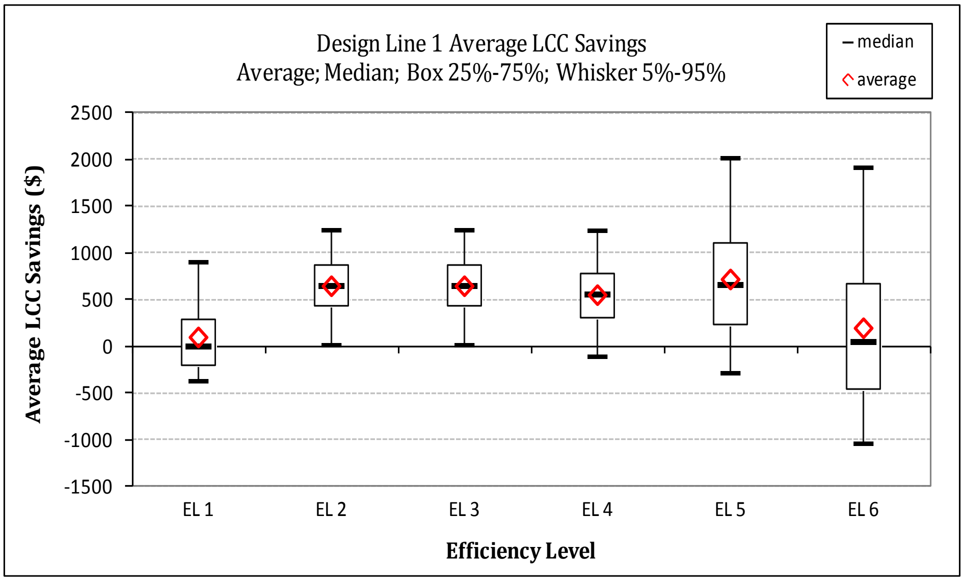

Figure 8D.1.18 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, High Load Growth Scenario

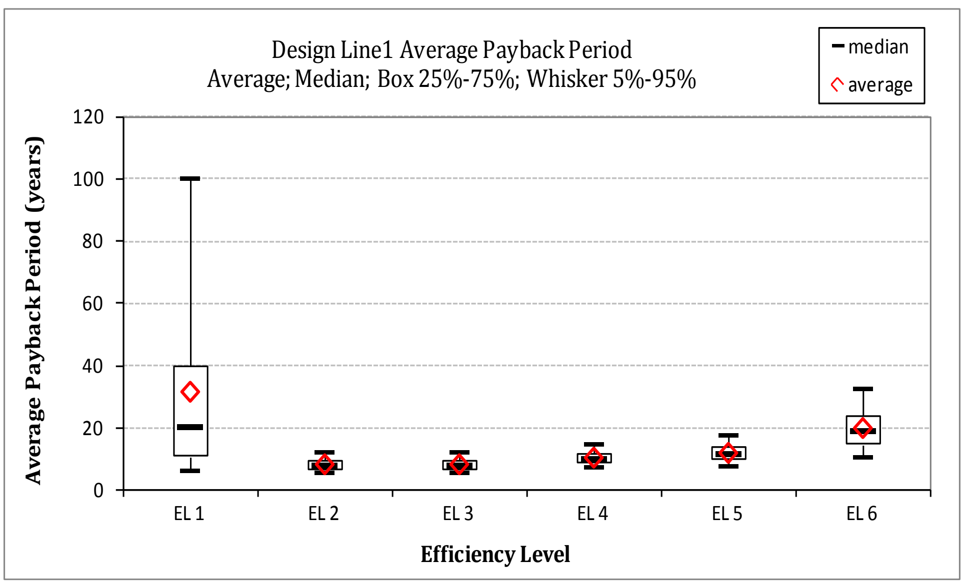

Figure 8D.1.19 Average Payback Period for Design Line 1 Representative Unit, High Load Growth Scenario

8D.1.10 Design Line 1 Results, Low Equipment Price Scenario

Table 8D.1.20 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Low Equipment Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	50.70%	4.00%	4.00%	5.90%	8.20%	39.20%
Transformers with No Change in LCC (%)	0.50%	0.50%	0.50%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	48.80%	95.50%	95.50%	94.10%	91.80%	60.80%
Mean LCC Savings ($)	90	701	701	617	769	312
Median LCC Savings ($)	-2	704	704	623	726	192

Table 8D.1.21 Summary Payback Period Results for Design Line 1 Representative Unit, Low Equipment Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	27.8	7.4	7.4	9.2	10.4	17.0
Median Payback (Years)	16.2	7.1	7.1	8.8	10.0	16.2
Transformers having Well Defined Payback (%)	83.30%	99.50%	99.50%	99.60%	99.80%	99.80%
Transformers having Undefined Payback (%)	16.70%	0.50%	0.50%	0.40%	0.20%	0.20%
Mean Retail Cost ($)	1,806	1,997	1,997	2,075	2,271	2,680
Mean Installation Cost ($)	2,232	2,272	2,272	2,346	2,415	2,606
Mean Operating Costs ($)	208	155	155	152	132	126
Mean Incremental First Cost ($)	278	508	508	660	925	1,525
Mean Operating Cost Savings ($)	18	71	71	74	95	100
Payback of Average Transformer	15.1	7.1	7.1	8.9	9.8	15.2

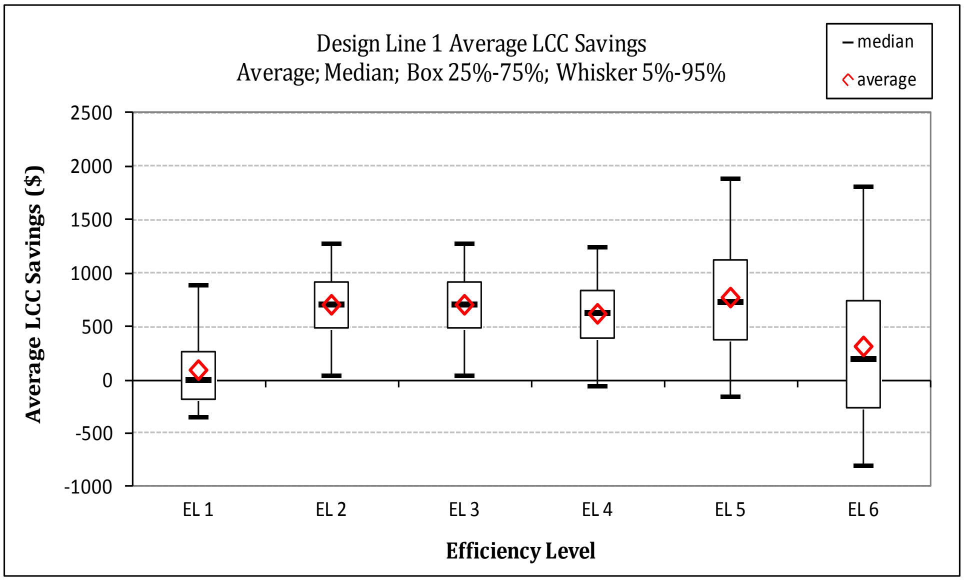

Figure 8D.1.20 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Low Equipment Price Scenario

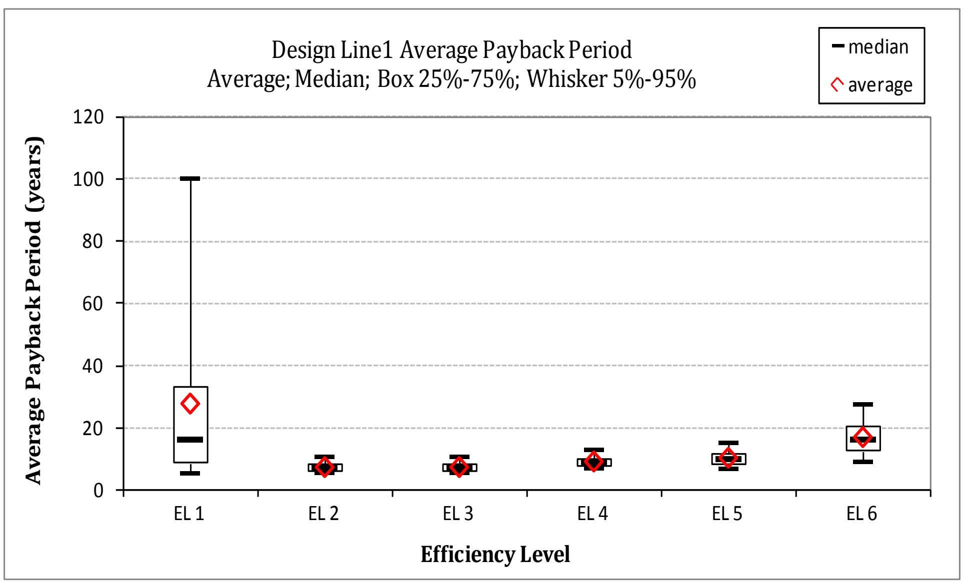

Figure 8D.1.21 Average Payback Period for Design Line 1 Representative Unit, Low Equipment Price Scenario

8D.1.11 Design Line 1 Results, High Equipment Price Scenario

Table 8D.1.22 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, High Equipment Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	69.90%	9.30%	9.30%	22.00%	35.10%	80.30%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	30.10%	90.70%	90.70%	78.00%	64.90%	19.70%
Mean LCC Savings ($)	-91	444	444	269	259	-591
Median LCC Savings ($)	-163	440	440	278	233	-715

Table 8D.1.23 Summary Payback Period Results for Design Line 1 Representative Unit, High Equipment Price Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	40.3	11.2	11.2	14.1	16.0	27.0
Median Payback (Years)	28.2	10.8	10.8	13.5	15.5	25.7
Transformers having Well Defined Payback (%)	85.80%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	14.20%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	2,922	3,249	3,249	3,406	3,762	4,563
Mean Installation Cost ($)	2,229	2,267	2,267	2,342	2,413	2,605
Mean Operating Costs ($)	211	155	155	152	131	126
Mean Incremental First Cost ($)	417	782	782	1,014	1,441	2,434
Mean Operating Cost Savings ($)	16	72	72	74	95	100
Payback of Average Transformer	26.6	10.9	10.9	13.6	15.1	24.2

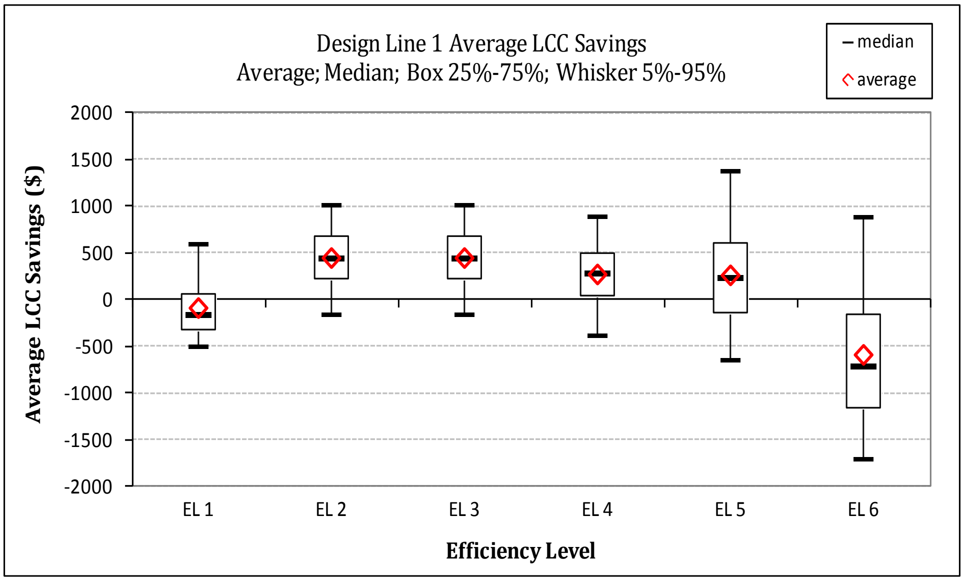

Figure 8D.1.22 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, High Equipment Price Scenario

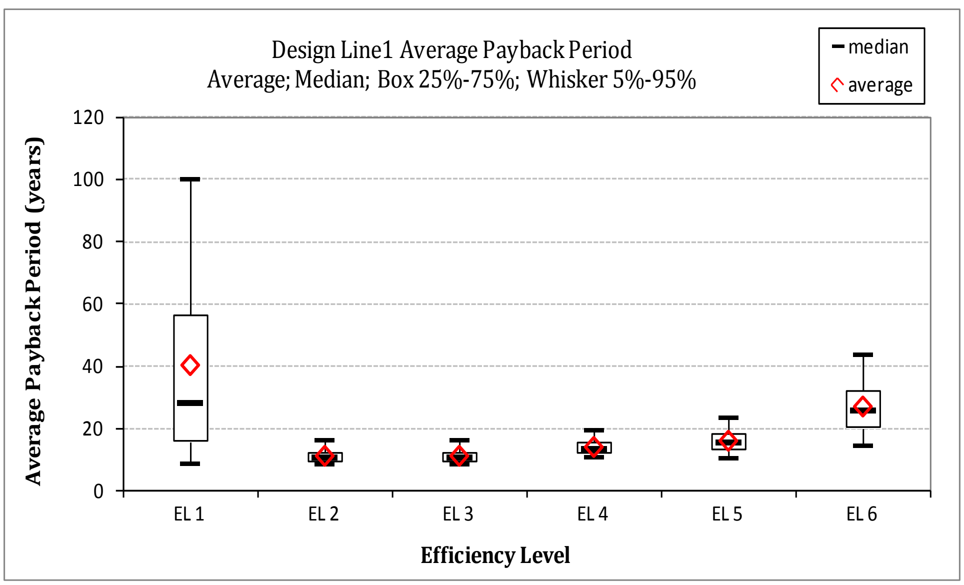

Figure 8D.1.23 Average Payback Period for Design Line 1 Representative Unit, High Equipment Price Scenario

8D.1.12 Design Line 1 Results, Low Electricity Price Trend Scenario

Table 8D.1.24 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Low Electricity Price Trend Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	60.10%	5.10%	5.10%	9.10%	15.70%	60.20%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	39.80%	94.80%	94.80%	90.90%	84.30%	39.80%
Mean LCC Savings ($)	17	592	592	475	552	-36
Median LCC Savings ($)	-64	595	595	488	527	-147

Table 8D.1.25 Summary Payback Period Results for Design Line 1 Representative Unit, Low Electricity Price Trend Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	31.9	8.4	8.4	10.6	12.1	20.2
Median Payback (Years)	20.5	8.0	8.0	10.2	11.6	19.3
Transformers having Well Defined Payback (%)	84.50%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	15.50%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	206	153	153	150	130	125
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	18	70	70	73	94	99
Payback of Average Transformer	18.6	8.1	8.1	10.3	11.4	18.2

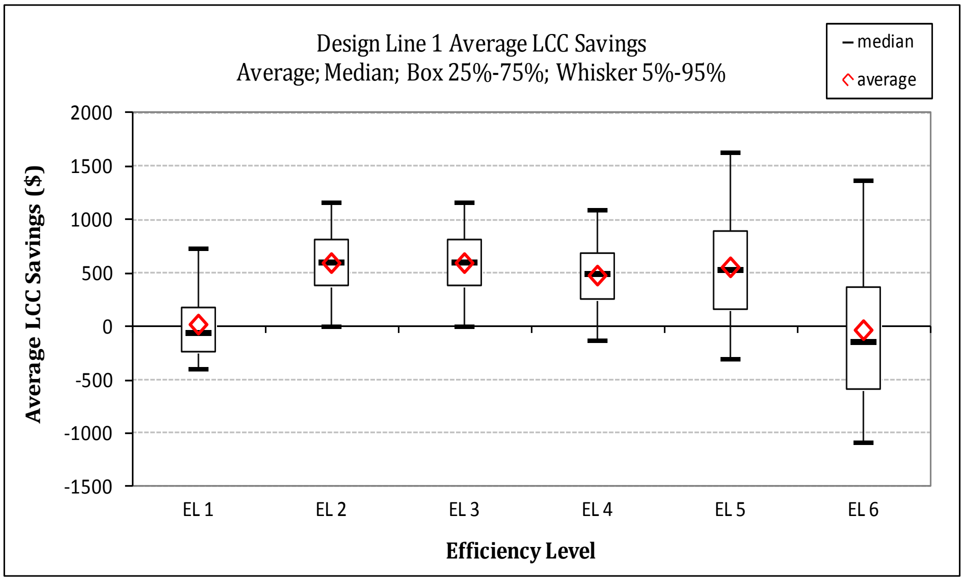

Figure 8D.1.24 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Low Electricity Price Trend Scenario

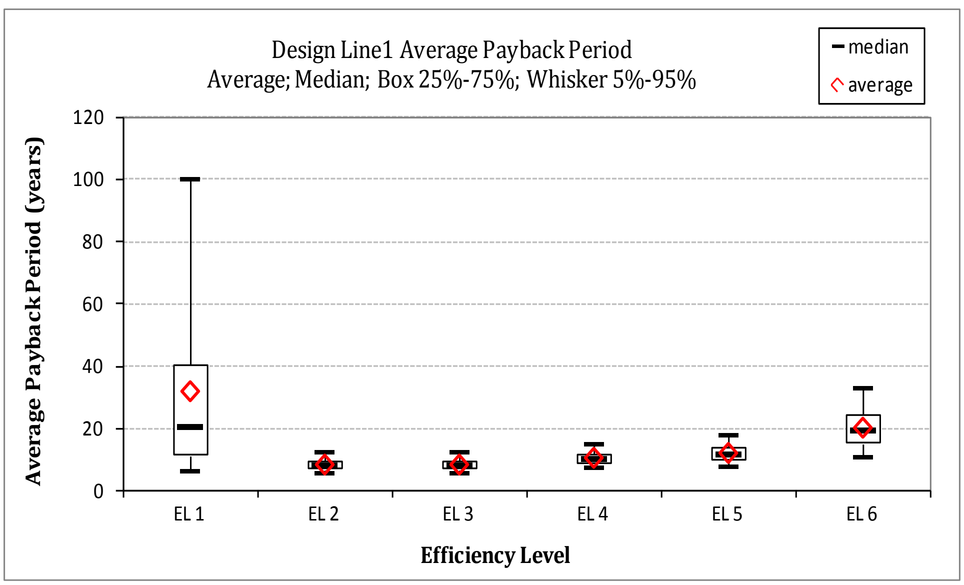

Figure 8D.1.25 Average Payback Period for Design Line 1 Representative Unit, Low Electricity Price Trend Scenario

8D.1.13 Design Line 1 Results, High Electricity Price Trend Scenario

Table 8D.1.26 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, High Electricity Price Trend Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	56.40%	4.20%	4.20%	7.50%	11.90%	49.80%
Transformers with No Change in LCC (%)	0.10%	0.10%	0.10%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	43.50%	95.70%	95.70%	92.50%	88.10%	50.20%
Mean LCC Savings ($)	51	696	696	585	703	130
Median LCC Savings ($)	-47	700	700	595	662	3

Table 8D.1.27 Summary Payback Period Results for Design Line 1 Representative Unit, High Electricity Price Trend Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	31.2	8.2	8.2	10.3	11.7	19.6
Median Payback (Years)	19.9	7.8	7.8	9.8	11.3	18.7
Transformers having Well Defined Payback (%)	84.50%	99.90%	99.90%	99.90%	100%	100%
Transformers having Undefined Payback (%)	15.50%	0.10%	0.10%	0.10%	0.00%	0.00%
Mean Retail Cost ($)	2,240	2,444	2,444	2,548	2,800	3,330
Mean Installation Cost ($)	2,229	2,271	2,271	2,345	2,415	2,606
Mean Operating Costs ($)	212	158	158	155	133	128
Mean Incremental First Cost ($)	327	572	572	750	1,071	1,794
Mean Operating Cost Savings ($)	18	73	73	75	97	102
Payback of Average Transformer	18.0	7.9	7.9	9.9	11.1	17.6

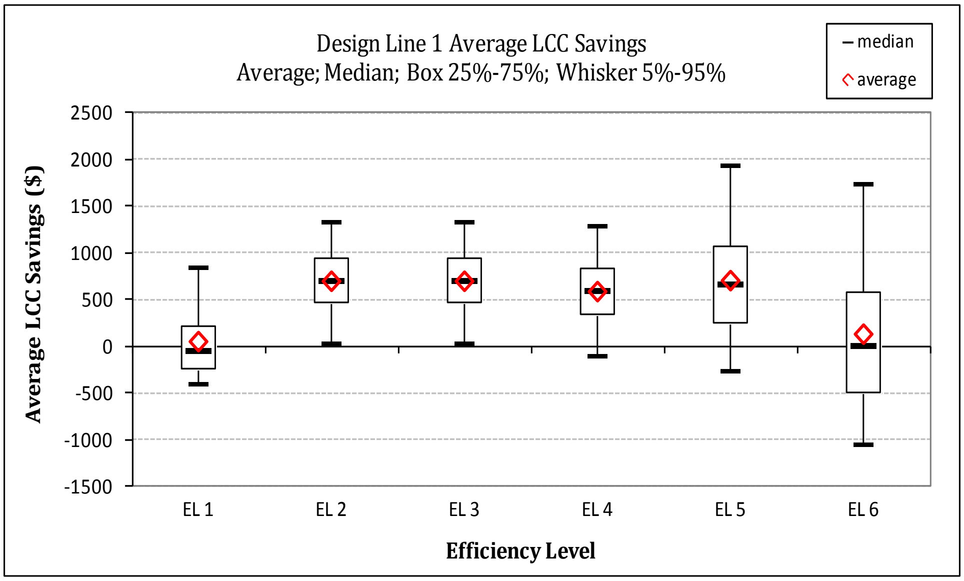

Figure 8D.1.26 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, High Electricity Price Trend Scenario

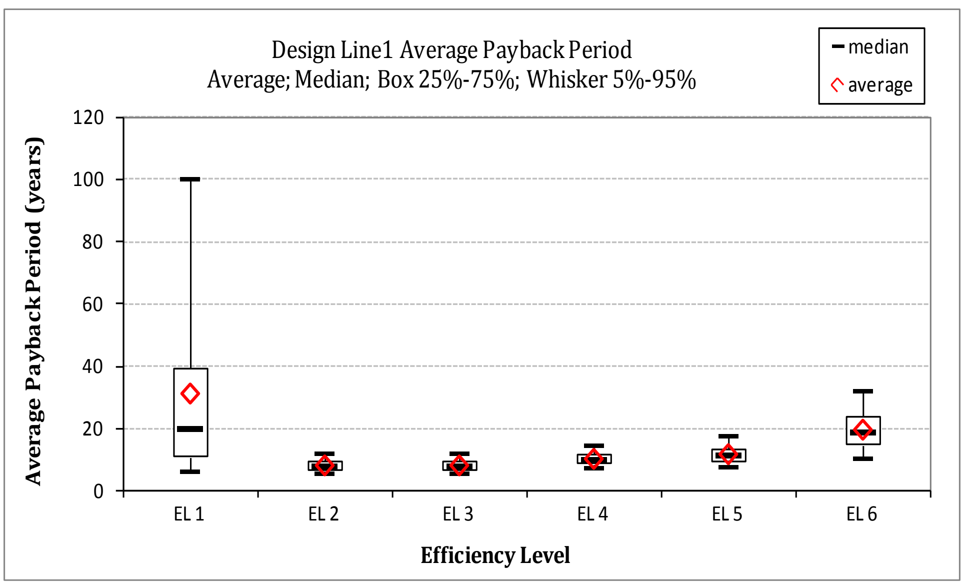

Figure 8D.1.27 Average Payback Period for Design Line 1 Representative Unit, High Electricity Price Trend Scenario

8D.1.14 Design Line 1 Results, Materials Exclusion Scenario

Table 8D.1.28 Summary Life-Cycle Cost Results for Design Line 1 Representative Unit, Materials Exclusion Scenario

	Efficiency Level					
	1	2	3	4	5	6
Efficiency (%)	99.16%	99.22%	99.25%	99.31%	99.42%	99.50%
Transformers with Net LCC Cost (%)	63.30%	83.00%	86.50%	0.00%	0.00%	0.00%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	36.70%	17.00%	13.50%	0.00%	0.00%	0.00%
Mean LCC Savings ($)	-19	-310	-552	NA	NA	NA
Median LCC Savings ($)	-80	-382	-669	NA	NA	NA

Table 8D.1.29 Summary Payback Period Results for Design Line 1 Representative Unit, Materials Exclusion Scenario

	Efficiency Level					
	1	2	3	4	5	6
Mean Payback (Years)	34.0	40.0	51.1	NA	NA	NA
Median Payback (Years)	22.3	33.6	42.8	NA	NA	NA
Transformers having Well Defined Payback (%)	83.50%	99.80%	97.80%	0.00%	0.00%	0.00%
Transformers having Undefined Payback (%)	16.50%	0.20%	2.20%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	2,228	2,756	2,982	NA	NA	NA
Mean Installation Cost ($)	2,229	2,269	2,368	NA	NA	NA
Mean Operating Costs ($)	213	197	194	NA	NA	NA
Mean Incremental First Cost ($)	315	882	1,207	NA	NA	NA
Mean Operating Cost Savings ($)	14	30	33	NA	NA	NA
Payback of Average Transformer	22.7	29.7	36.8	#VALUE!	#VALUE!	NA

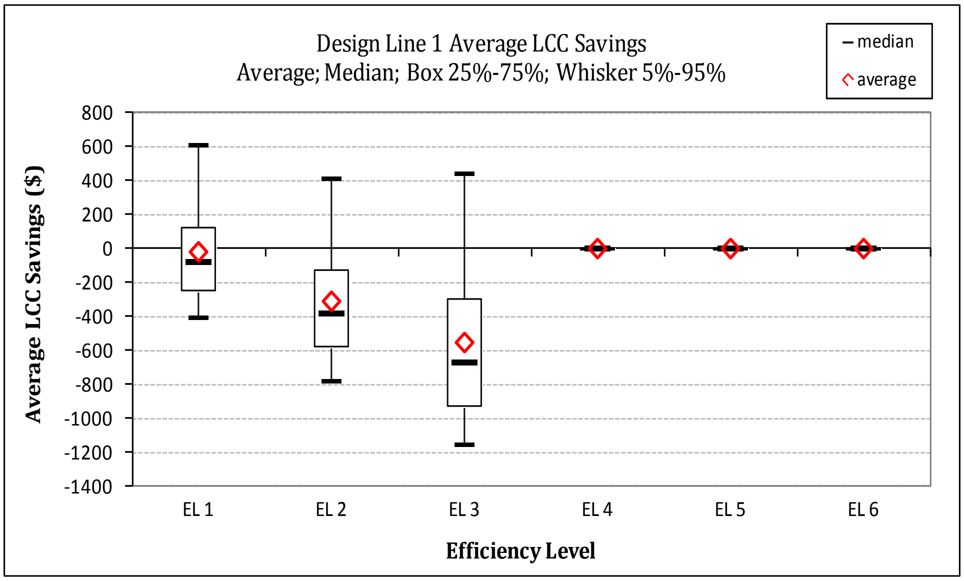

Figure 8D.1.28 Average Life-Cycle Cost Savings for Design Line 1 Representative Unit, Materials Exclusion Scenario

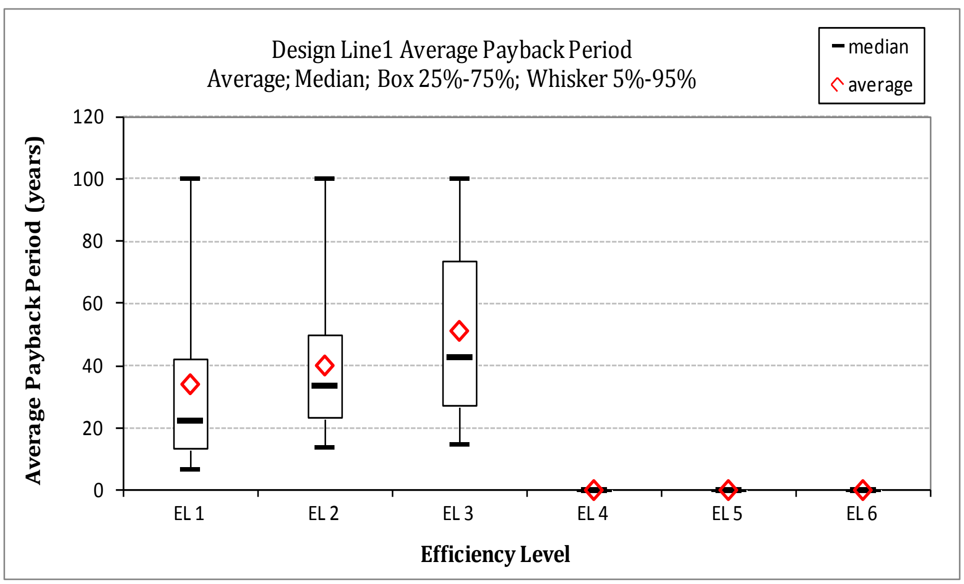

Figure 8D.1.29 Average Payback Period for Design Line 1 Representative Unit, Materials Exclusion Scenario

8D.2 DESIGN LINE 7 RESULTS

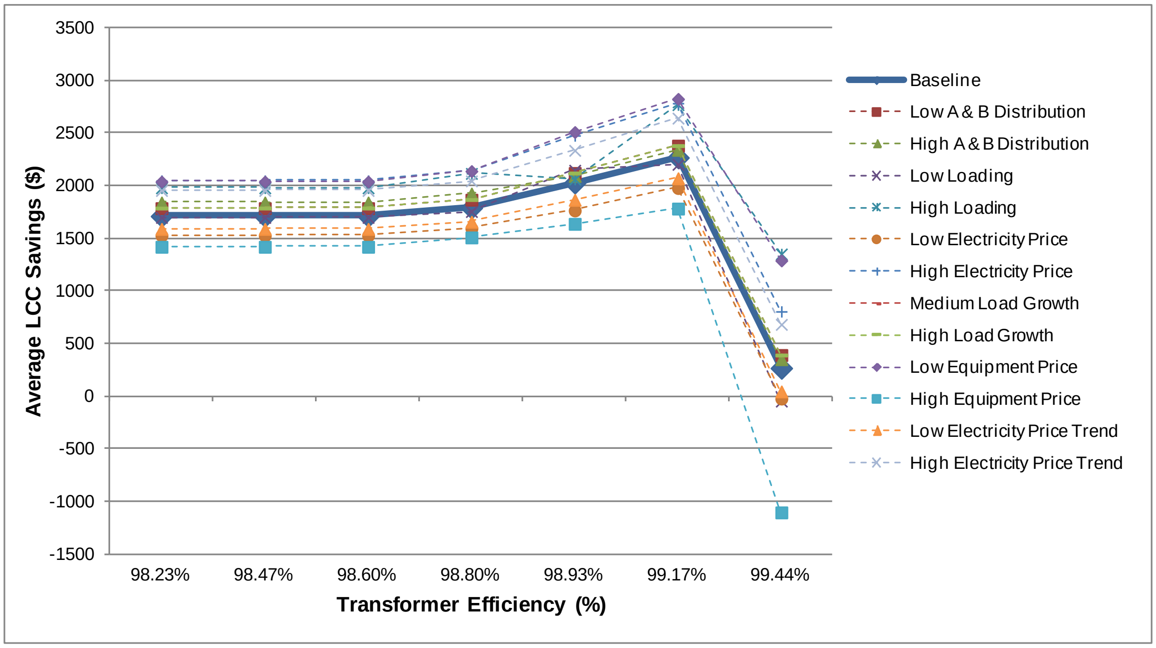

Figure 8D.2.1 Average LCC Savings ($) by Scenario for Design Line 7

Table 8D.2.1 LCC Savings ($), Summary Table for Design Line 7

Scenario	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Baseline	1714	1714	1714	1793	2030	2270	270
Low A & B Distribution	1789	1789	1789	1869	2123	2383	394
High A & B Distribution	1843	1843	1843	1928	2095	2343	354
Low Loading	1701	1701	1701	1757	2149	2205	-44
High Loading	1982	1982	1982	2119	2065	2772	1354
Low Electricity Price	1529	1529	1529	1597	1767	1980	-20
High Electricity Price	2051	2051	2051	2145	2479	2786	808
No Load Growth	1790	1790	1790	1871	2123	2383	394
High Load Growth	1790	1790	1790	1871	2123	2383	394
Low Equipment Price	2041	2041	2041	2141	2512	2827	1292
High Equipment Price	1422	1422	1422	1511	1640	1785	-1101
Low Electricity Price Trend	1592	1592	1592	1660	1868	2073	48
High Electricity Price Trend	1957	1957	1957	2048	2338	2644	685

8D.2.15 Design Line 7 Results, Baseline Scenario

Table 8D.2.2 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, Baseline Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	1.8%	1.8%	1.8%	2.0%	2.8%	3.7%	46.4%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	98.2%	98.2%	98.2%	98.0%	97.2%	96.3%	53.6%
Mean LCC Savings ($)	1714	1714	1714	1793	2030	2270	270
Median LCC Savings ($)	1649	1649	1649	1724	1931	2174	123

Table 8D.2.3 Summary Payback Period Results for Design Line 7 Representative Unit, Baseline Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.7	4.7	4.7	4.9	5.9	7.0	18.6
Median Payback (Years)	4.5	4.5	4.5	4.7	5.8	6.9	18.1
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,537	3,537	3,537	3,583	3,881	4,161	6,049
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,731	1,839	2,362
Mean Operating Costs ($)	222	222	222	214	187	153	131
Mean Incremental First Cost ($)	531	531	531	594	863	1,250	3,662
Mean Operating Cost Savings ($)	121	121	121	129	156	190	212
Payback of Average Transformer	4.4	4.4	4.4	4.6	5.5	6.6	17.3

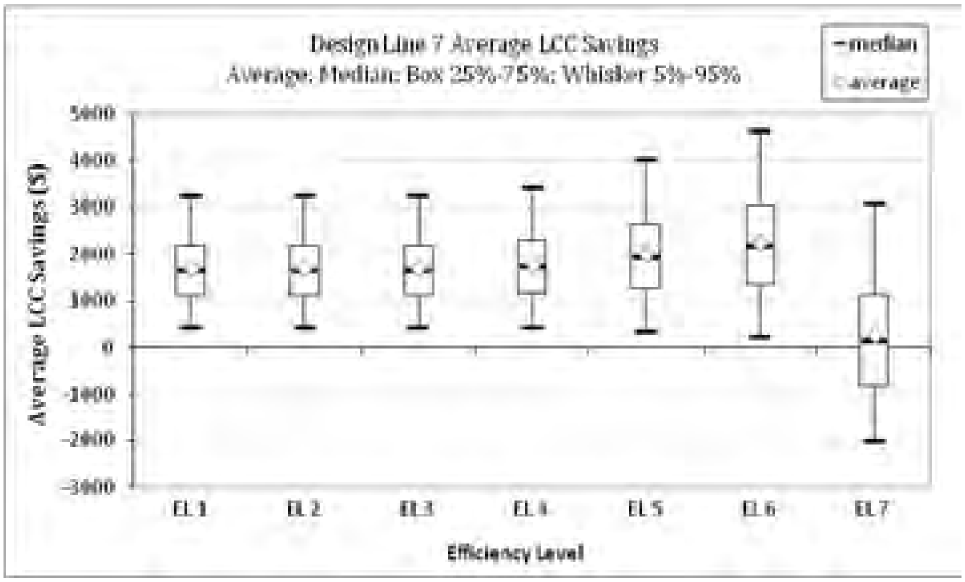

Figure 8D.2.2 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, Baseline Scenario

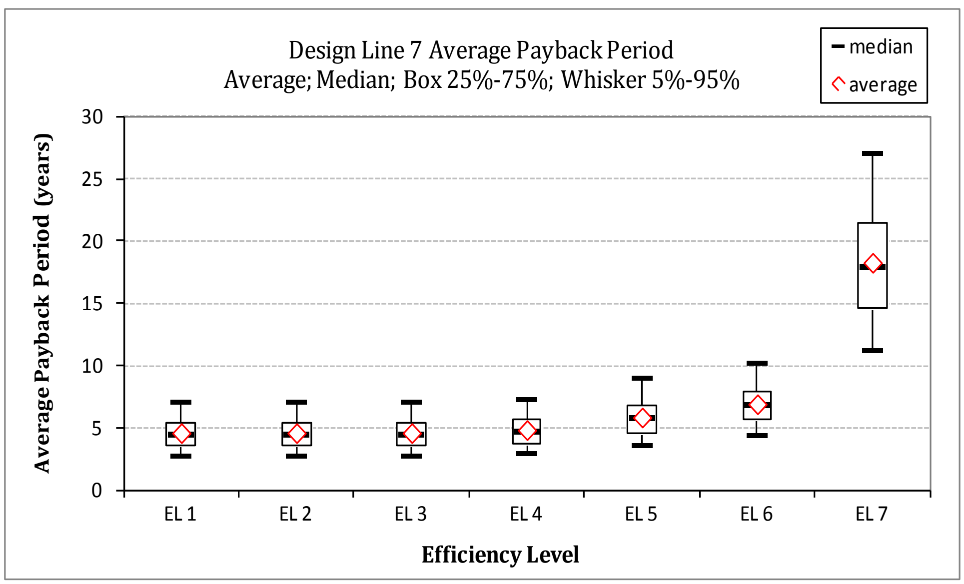

Figure 8D.2.3 Average Payback Period for Design Line 7 Representative Unit, Baseline Scenario

8D.2.16 Design Line 7 Results, Low A & B Distribution Scenario

Table 8D.2.4 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, Low A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.8%	0.8%	0.8%	1.4%	2.0%	2.7%	43.4%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.2%	99.2%	99.2%	98.6%	98.0%	97.3%	56.6%
Mean LCC Savings ($)	1789	1789	1789	1869	2123	2383	394
Median LCC Savings ($)	1694	1694	1694	1769	2003	2243	198

Table 8D.2.5 Summary Payback Period Results for Design Line 7 Representative Unit, Low A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.6	4.6	4.6	4.8	5.9	6.9	18.3
Median Payback (Years)	4.5	4.5	4.5	4.7	5.8	6.8	17.9
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,580	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	224	224	224	217	189	155	132
Mean Incremental First Cost ($)	530	530	530	592	863	1,250	3,660
Mean Operating Cost Savings ($)	123	123	123	131	158	193	215
Payback of Average Transformer	4.3	4.3	4.3	4.5	5.5	6.5	17.0

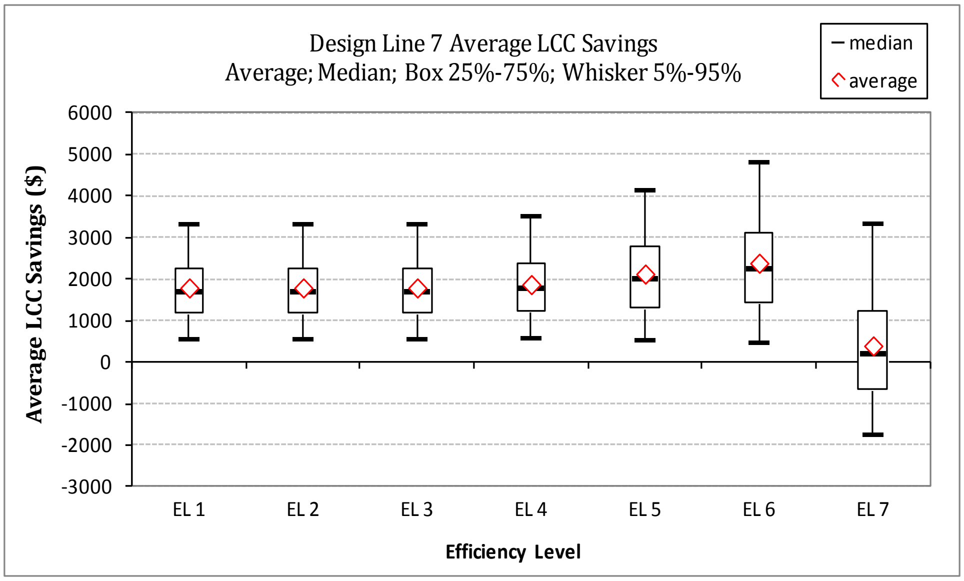

Figure 8D.2.4 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, Low A & B Distribution Scenario

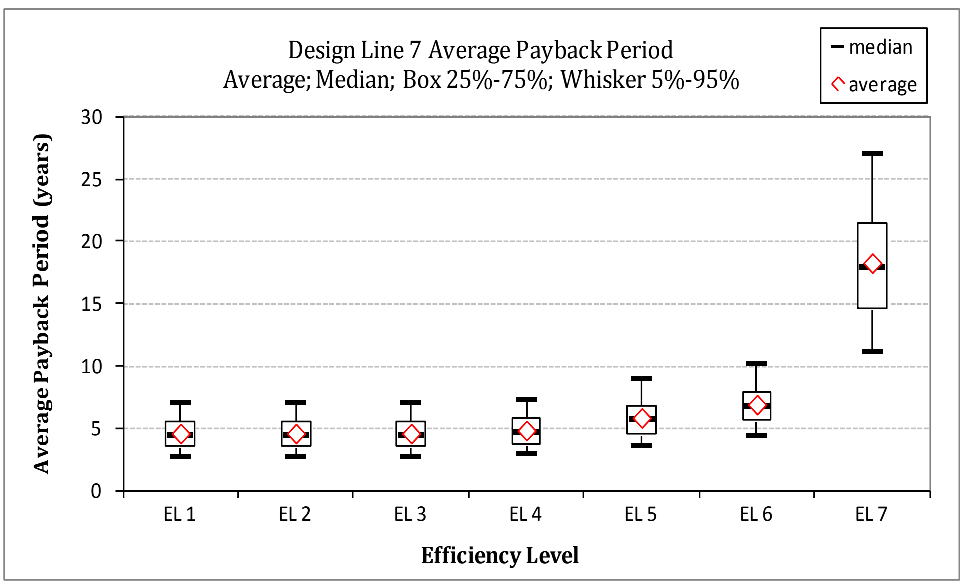

Figure 8D.2.5 Average Payback Period for Design Line 7 Representative Unit, Low A & B Distribution Scenario

8D.2.17 Design Line 7 Results, High A & B Distribution Scenario

Table 8D.2.6 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, High A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.8%	0.8%	0.8%	1.1%	2.0%	2.7%	44.2%
Transformers with No Change in LCC (%)	0.4%	0.4%	0.4%	0.1%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	98.8%	98.8%	98.8%	98.8%	98.0%	97.3%	55.8%
Mean LCC Savings ($)	1843	1843	1843	1928	2095	2343	354
Median LCC Savings ($)	1719	1719	1719	1802	1964	2216	164

Table 8D.2.7 Summary Payback Period Results for Design Line 7 Representative Unit, High A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.6	4.6	4.6	4.9	5.9	7.0	18.5
Median Payback (Years)	4.4	4.4	4.4	4.7	5.8	6.9	18.1
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,555	3,555	3,555	3,614	3,881	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,756	1,729	1,839	2,362
Mean Operating Costs ($)	218	218	218	210	189	155	132
Mean Incremental First Cost ($)	544	544	544	616	856	1,245	3,655
Mean Operating Cost Savings ($)	127	127	127	135	156	190	213
Payback of Average Transformer	4.3	4.3	4.3	4.6	5.5	6.5	17.2

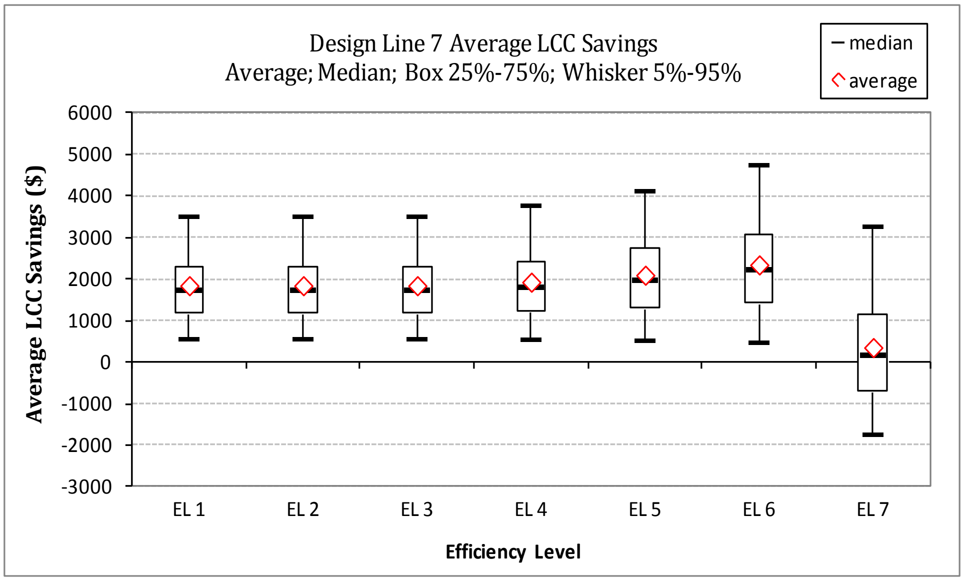

Figure 8D.2.6 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, High A & B Distribution Scenario

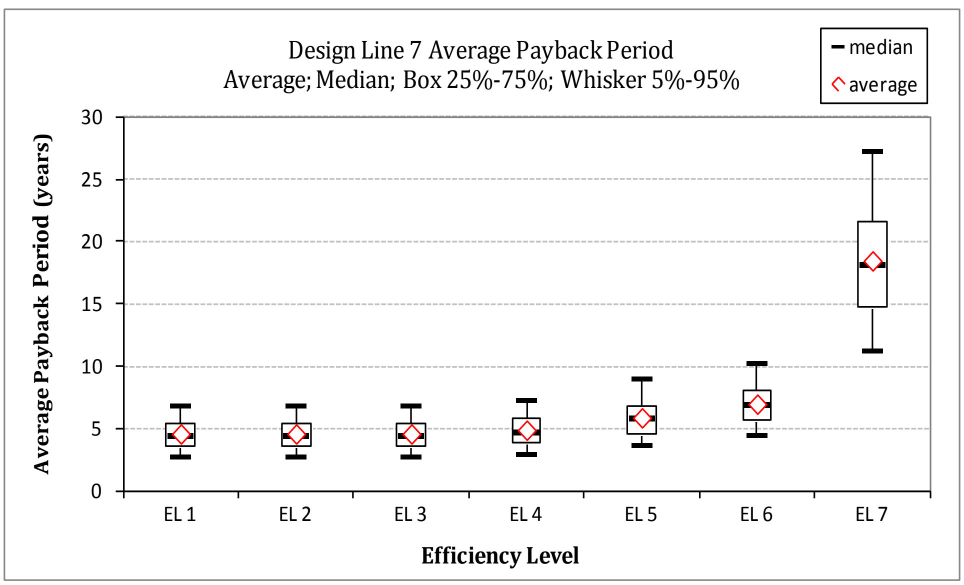

Figure 8D.2.7 Average Payback Period for Design Line 7 Representative Unit, High A & B Distribution Scenario

8D.2.18 Design Line 7 Results, Low Loading Scenario

Table 8D.2.8 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, Low Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	1.2%	1.2%	1.2%	1.6%	2.0%	3.2%	56.8%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	98.8%	98.8%	98.8%	98.4%	98.0%	96.8%	43.2%
Mean LCC Savings ($)	1701	1701	1701	1757	2149	2205	-44
Median LCC Savings ($)	1617	1617	1617	1685	2028	2099	-146

Table 8D.2.9 Summary Payback Period Results for Design Line 7 Representative Unit, Low Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.8	4.8	4.8	5.1	5.8	7.3	20.3
Median Payback (Years)	4.6	4.6	4.6	4.9	5.7	7.2	19.9
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	199	199	199	193	158	134	126
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	118	118	118	124	160	183	192
Payback of Average Transformer	4.5	4.5	4.5	4.8	5.4	6.8	19.1

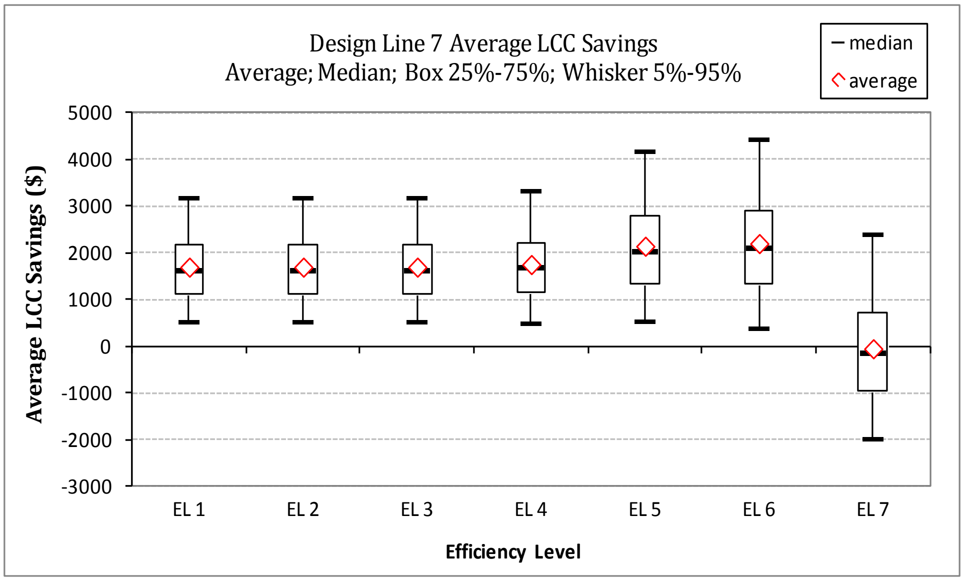

Figure 8D.2.8 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, Low Loading Scenario

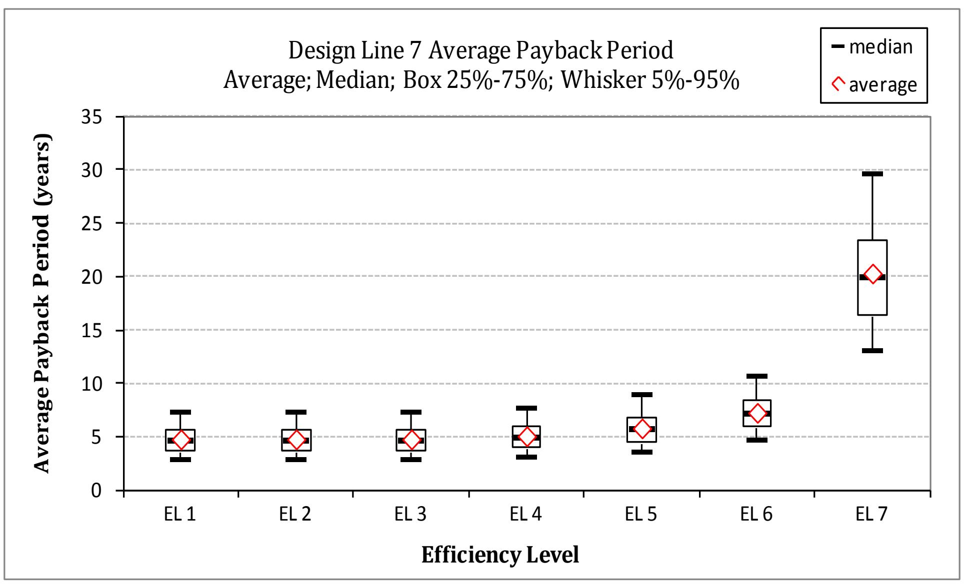

Figure 8D.2.9 Average Payback Period for Design Line 7 Representative Unit, Low Loading Scenario

8D.2.19 Design Line 7 Results, High Loading Scenario

Table 8D.2.10 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, High Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.8%	0.8%	0.8%	1.0%	2.0%	2.4%	26.6%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.2%	99.2%	99.2%	99.0%	98.0%	97.6%	73.4%
Mean LCC Savings ($)	1982	1982	1982	2119	2065	2772	1354
Median LCC Savings ($)	1874	1874	1874	2013	1928	2583	1024

Table 8D.2.11 Summary Payback Period Results for Design Line 7 Representative Unit, High Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.3	4.3	4.3	4.4	6.0	6.3	15.2
Median Payback (Years)	4.1	4.1	4.1	4.3	5.9	6.2	14.9
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	279	279	279	269	257	199	147
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	133	133	133	144	155	213	266
Payback of Average Transformer	4.0	4.0	4.0	4.1	5.6	5.9	13.8

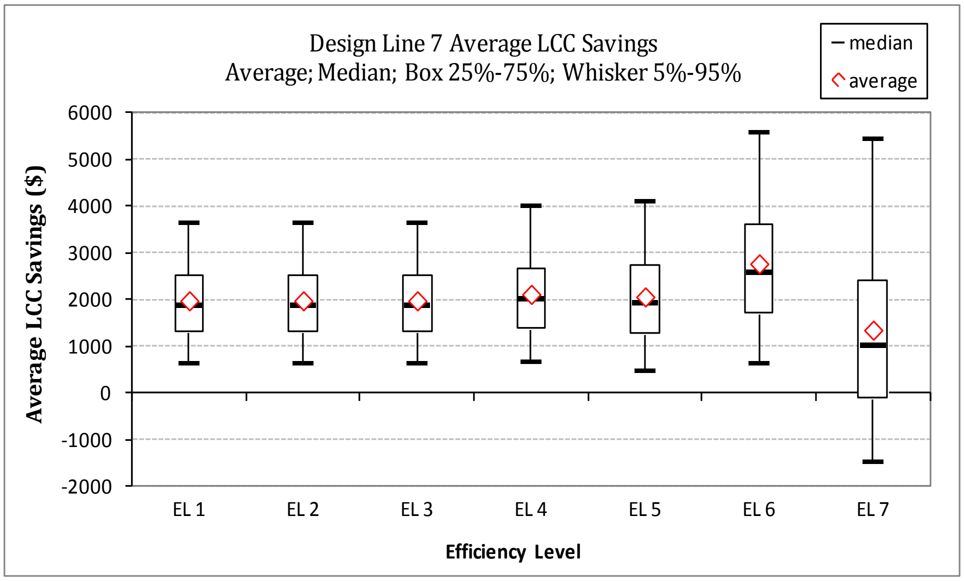

Figure 8D.2.10 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, High Loading Scenario

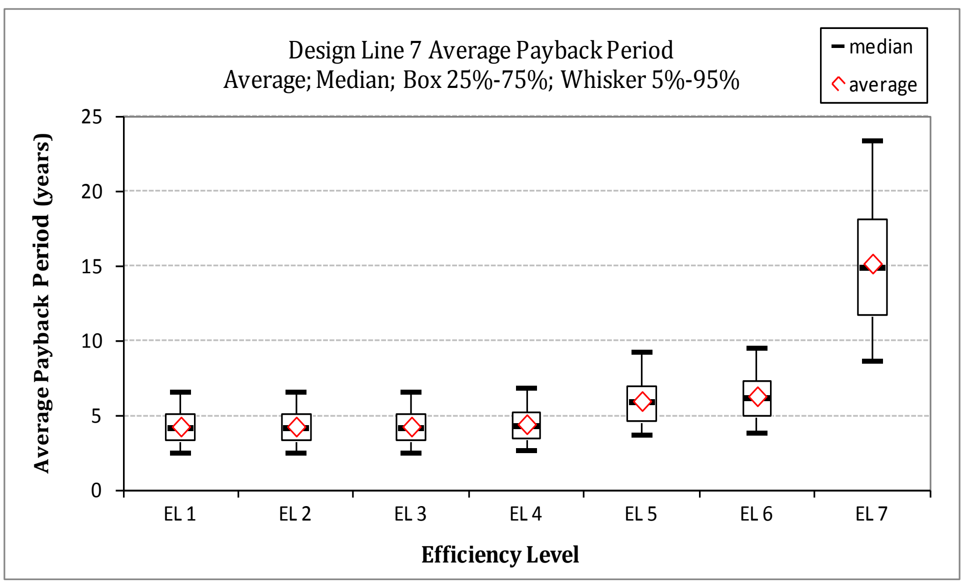

Figure 8D.2.11 Average Payback Period for Design Line 7 Representative Unit, High Loading Scenario

8D.2.20 Design Line 7 Results, Low Electricity Price Scenario

Table 8D.2.12 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, Low Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	1.4%	1.4%	1.4%	1.8%	2.4%	3.2%	56.3%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	98.6%	98.6%	98.6%	98.2%	97.6%	96.8%	43.7%
Mean LCC Savings ($)	1529	1529	1529	1597	1767	1980	-20
Median LCC Savings ($)	1456	1456	1456	1521	1662	1867	-180

Table 8D.2.13 Summary Payback Period Results for Design Line 7 Representative Unit, Low Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	5.2	5.2	5.2	5.4	6.6	7.8	20.3
Median Payback (Years)	5.0	5.0	5.0	5.3	6.5	7.6	19.9
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	208	208	208	201	178	146	124
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	109	109	109	116	139	171	193
Payback of Average Transformer	4.9	4.9	4.9	5.1	6.2	7.3	18.9

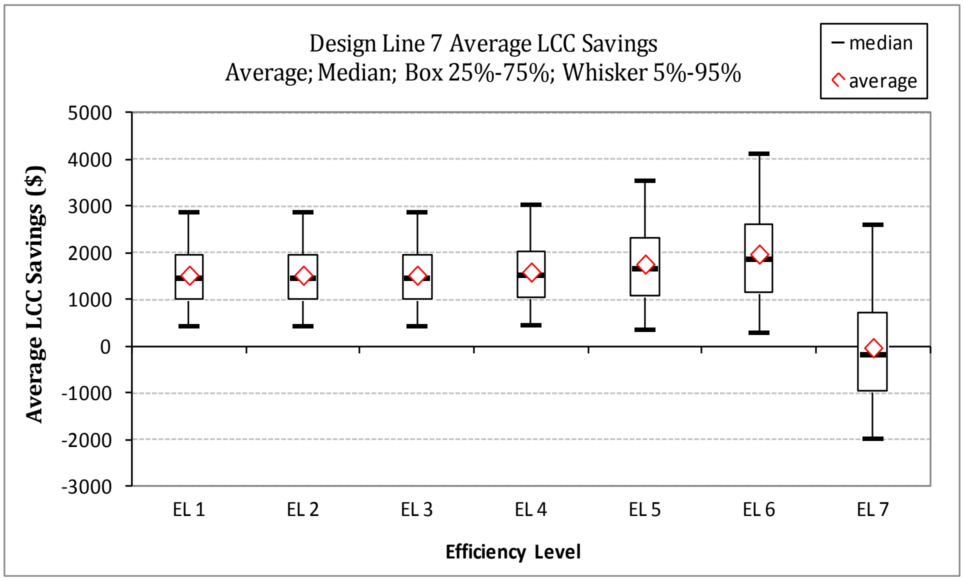

Figure 8D.2.12 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, Low Electricity Price Scenario

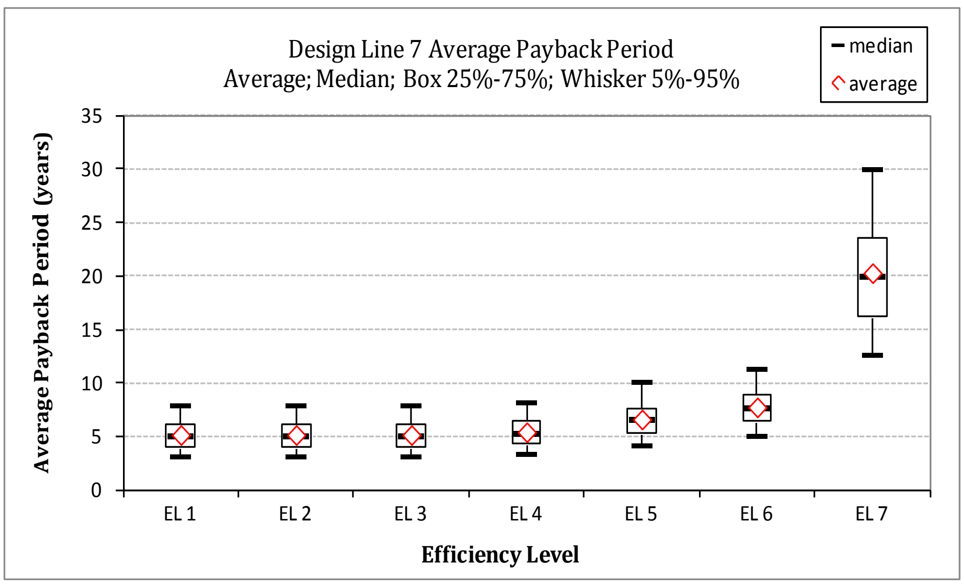

Figure 8D.2.13 Average Payback Period for Design Line 7 Representative Unit, Low Electricity Price Scenario

8D.2.21 Design Line 7 Results, High Electricity Price Scenario

Table 8D.2.14 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, High Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.7%	0.7%	0.7%	0.8%	1.7%	2.3%	33.9%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.3%	99.3%	99.3%	99.2%	98.3%	97.7%	66.1%
Mean LCC Savings ($)	2051	2051	2051	2145	2479	2786	808
Median LCC Savings ($)	1945	1945	1945	2015	2320	2637	603

Table 8D.2.15 Summary Payback Period Results for Design Line 7 Representative Unit, High Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.2	4.2	4.2	4.4	5.3	6.3	16.6
Median Payback (Years)	4.0	4.0	4.0	4.2	5.2	6.2	16.3
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	240	240	240	232	200	163	140
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	137	137	137	145	177	214	237
Payback of Average Transformer	3.9	3.9	3.9	4.1	4.9	5.8	15.4

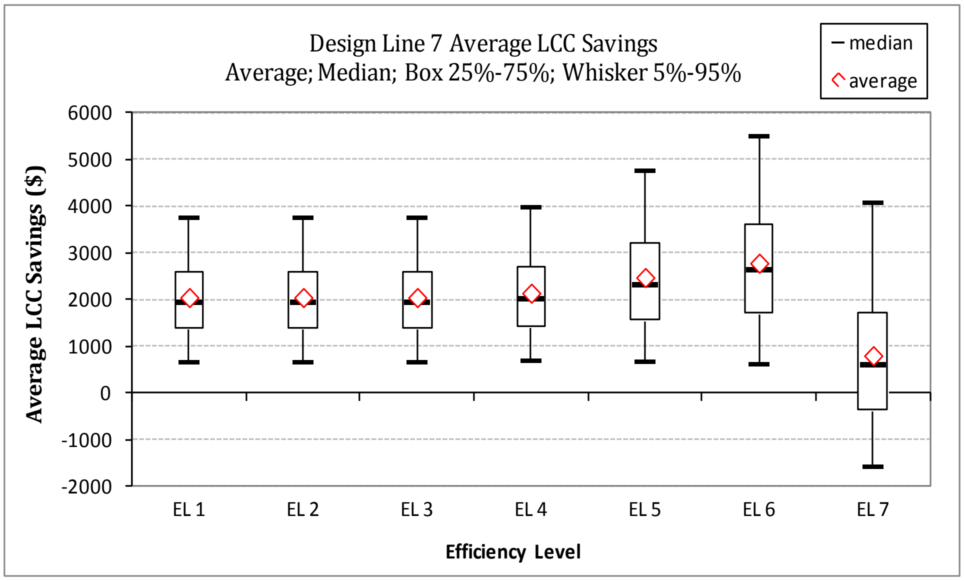

Figure 8D.2.14 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, High Electricity Price Scenario

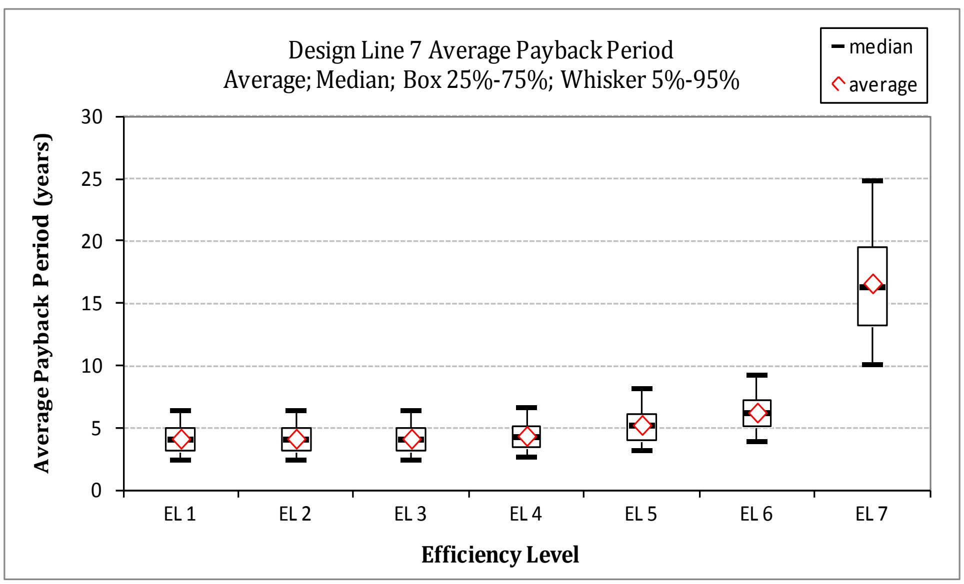

Figure 8D.2.15 Average Payback Period for Design Line 7 Representative Unit, High Electricity Price Scenario

8D.2.22 Design Line 7 Results, No Load Growth Scenario

Table 8D.2.16 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, No Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.8%	0.8%	0.8%	1.4%	2.0%	2.7%	43.4%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.2%	99.2%	99.2%	98.6%	98.0%	97.3%	56.6%
Mean LCC Savings ($)	1790	1790	1790	1871	2123	2383	394
Median LCC Savings ($)	1694	1694	1694	1769	2001	2243	198

Table 8D.2.17 Summary Payback Period Results for Design Line 7 Representative Unit, No Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.6	4.6	4.6	4.8	5.9	6.9	18.3
Median Payback (Years)	4.5	4.5	4.5	4.7	5.8	6.8	17.9
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	224	224	224	217	189	155	132
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	123	123	123	131	158	193	215
Payback of Average Transformer	4.3	4.3	4.3	4.5	5.5	6.5	17.0

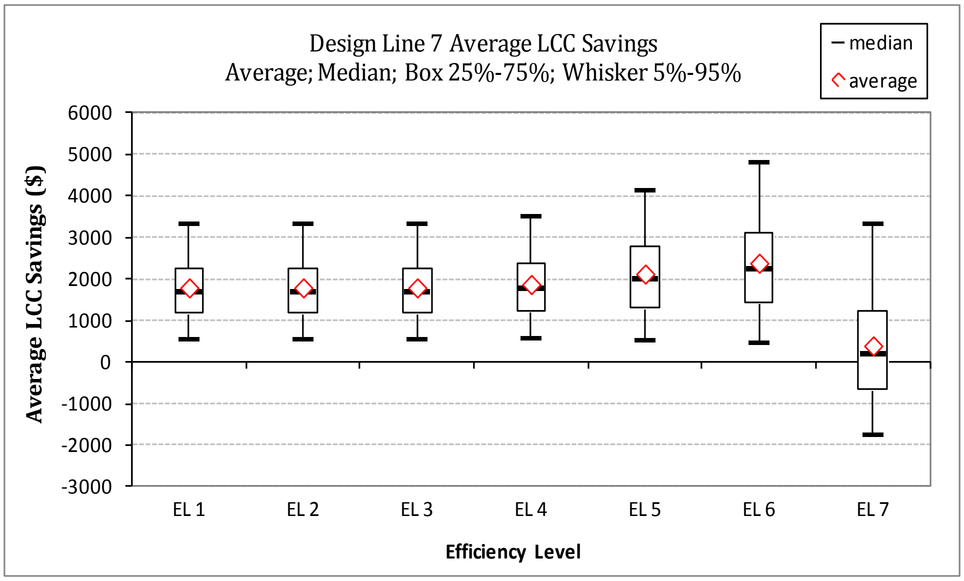

Figure 8D.2.16 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, No Load Growth Scenario

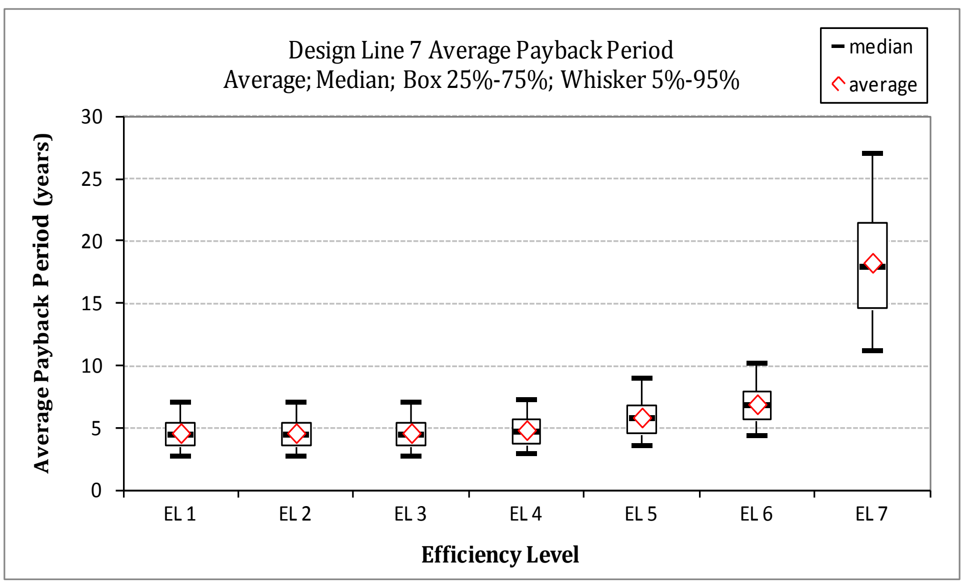

Figure 8D.2.17 Average Payback Period for Design Line 7 Representative Unit, No Load Growth Scenario

8D.2.23 Design Line 7 Results, High Load Growth Scenario

Table 8D.2.18 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, High Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.8%	0.8%	0.8%	1.4%	2.0%	2.7%	43.4%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.2%	99.2%	99.2%	98.6%	98.0%	97.3%	56.6%
Mean LCC Savings ($)	1790	1790	1790	1871	2123	2383	394
Median LCC Savings ($)	1694	1694	1694	1769	2001	2243	198

Table 8D.2.19 Summary Payback Period Results for Design Line 7 Representative Unit, High Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.6	4.6	4.6	4.8	5.9	6.9	18.3
Median Payback (Years)	4.5	4.5	4.5	4.7	5.8	6.8	17.9
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	224	224	224	217	189	155	132
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	123	123	123	131	158	193	215
Payback of Average Transformer	4.3	4.3	4.3	4.5	5.5	6.5	17.0

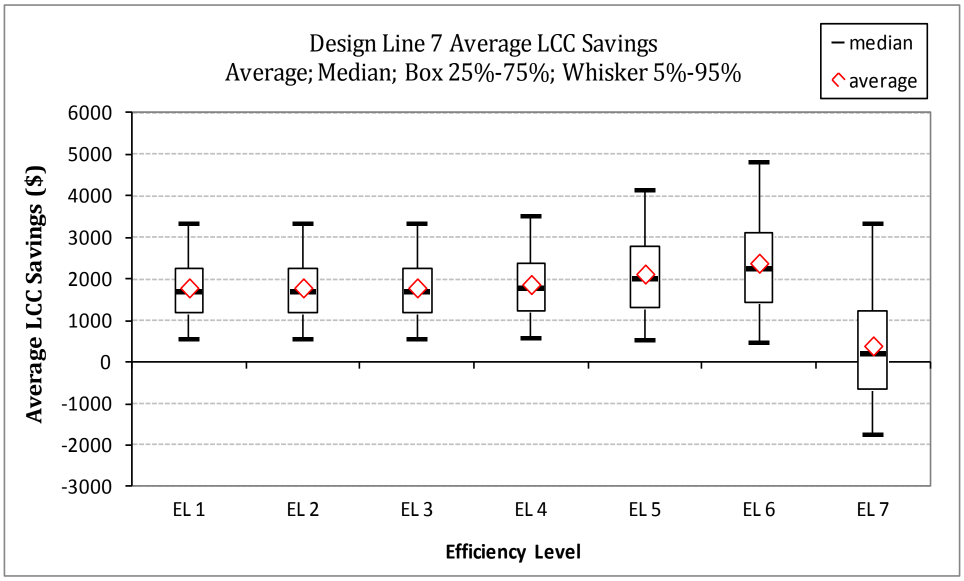

Figure 8D.2.18 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, High Load Growth Scenario

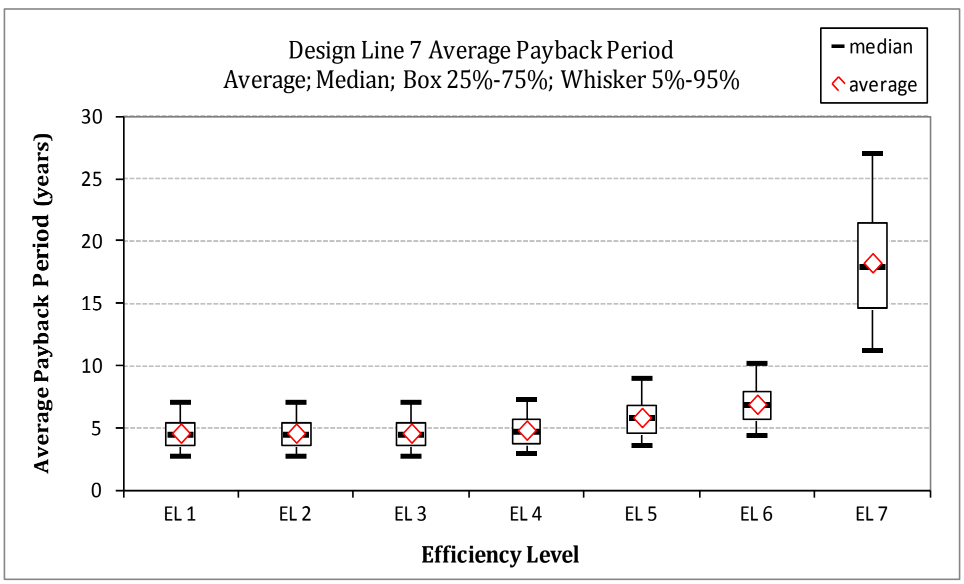

Figure 8D.2.19 Average Payback Period for Design Line 7 Representative Unit, High Load Growth Scenario

8D.2.24 Design Line 7 Results, Low Equipment Price Scenario

Table 8D.2.20 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, Low Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.3%	0.3%	0.3%	0.3%	0.6%	1.1%	20.0%
Transformers with No Change in LCC (%)	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.6%	99.6%	99.6%	99.7%	99.4%	98.9%	80.0%
Mean LCC Savings ($)	2041	2041	2041	2141	2512	2827	1292
Median LCC Savings ($)	1957	1957	1957	2054	2377	2704	1095

Table 8D.2.21 Summary Payback Period Results for Design Line 7 Representative Unit, Low Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	2.4	2.4	2.4	2.7	3.2	4.4	13.8
Median Payback (Years)	2.4	2.4	2.4	2.6	3.1	4.3	13.4
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,004	3,004	3,004	3,039	3,203	3,422	4,853
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,729	1,839	2,362
Mean Operating Costs ($)	224	224	224	215	189	155	132
Mean Incremental First Cost ($)	276	276	276	329	462	790	2,744
Mean Operating Cost Savings ($)	123	123	123	131	158	192	214
Payback of Average Transformer	2.2	2.2	2.2	2.5	2.9	4.1	12.8

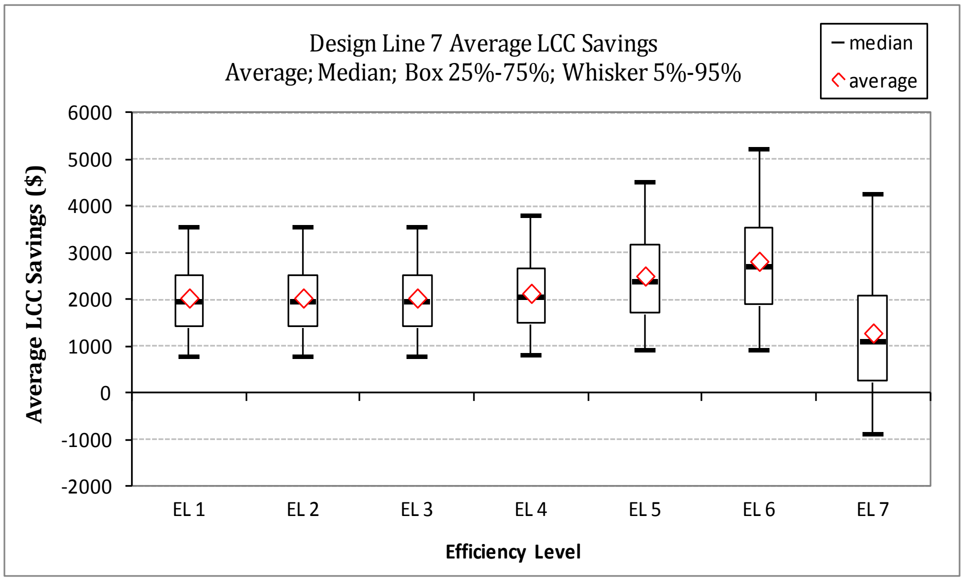

Figure 8D.2.20 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, Low Equipment Price Scenario

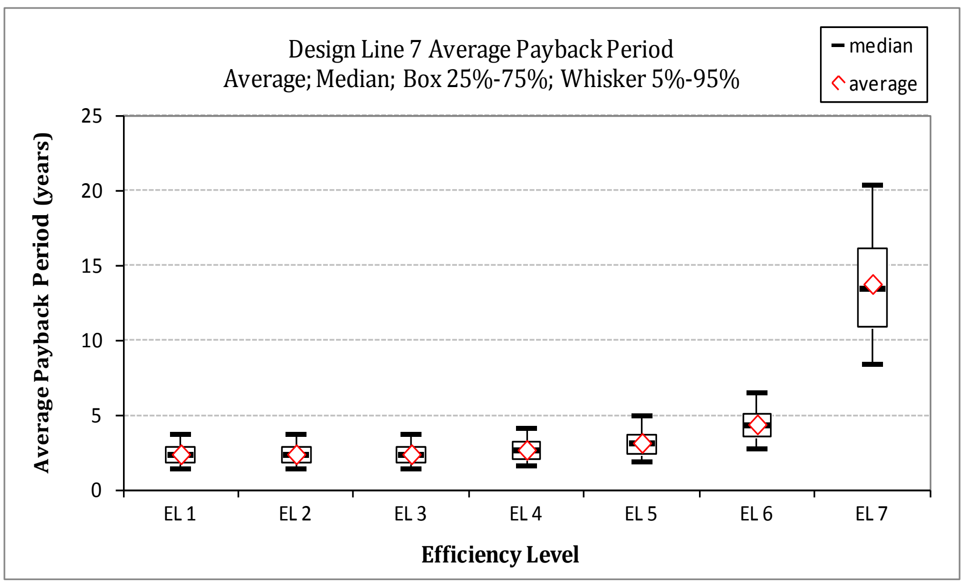

Figure 8D.2.21 Average Payback Period for Design Line 7 Representative Unit, Low Equipment Price Scenario

8D.2.25 Design Line 7 Results, High Equipment Price Scenario

Table 8D.2.22 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, High Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	3.2%	3.2%	3.2%	3.5%	4.7%	6.3%	79.6%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	96.8%	96.8%	96.8%	96.5%	95.3%	93.7%	20.4%
Mean LCC Savings ($)	1422	1422	1422	1511	1640	1785	-1101
Median LCC Savings ($)	1346	1346	1346	1420	1506	1654	-1298

Table 8D.2.23 Summary Payback Period Results for Design Line 7 Representative Unit, High Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.8	7.8	7.8	7.9	9.1	10.2	25.8
Median Payback (Years)	7.6	7.6	7.6	7.7	9.0	10.1	25.1
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	4,676	4,676	4,676	4,735	5,138	5,525	8,309
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,729	1,838	2,362
Mean Operating Costs ($)	224	224	224	215	189	155	132
Mean Incremental First Cost ($)	891	891	891	969	1,340	1,835	5,143
Mean Operating Cost Savings ($)	123	123	123	131	158	192	214
Payback of Average Transformer	7.3	7.3	7.3	7.4	8.5	9.6	24.0

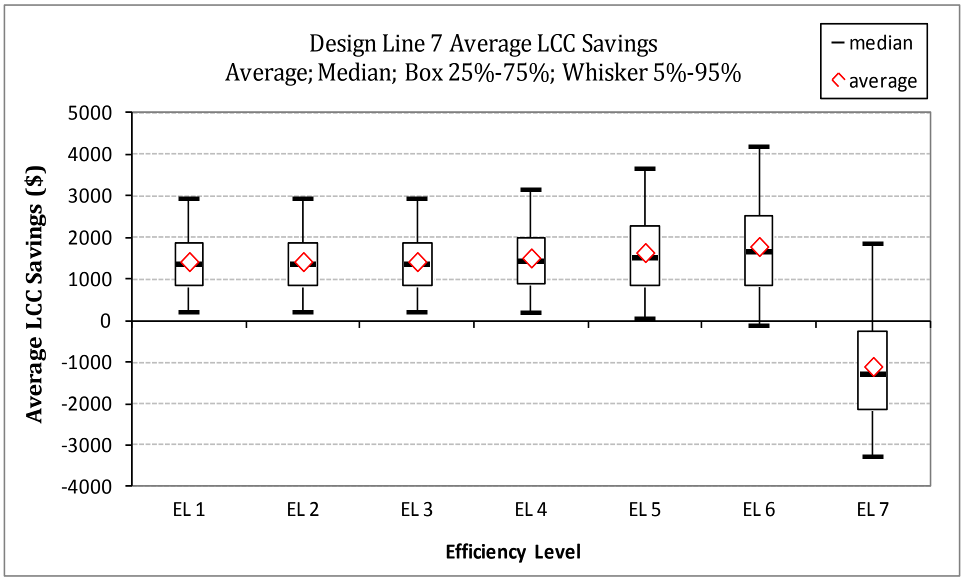

Figure 8D.2.22 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, High Equipment Price Scenario

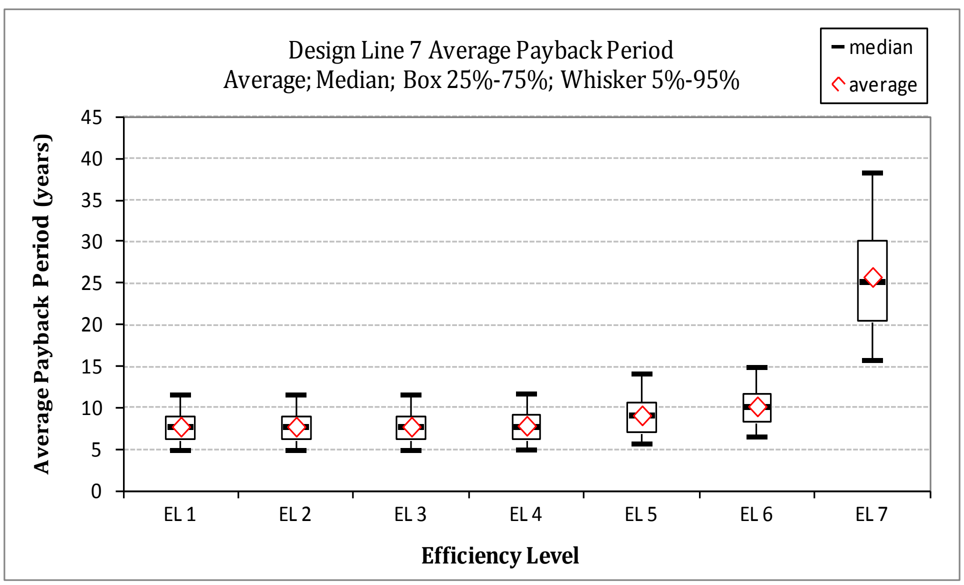

Figure 8D.2.23 Average Payback Period for Design Line 7 Representative Unit, High Equipment Price Scenario

8D.2.26 Design Line 7 Results, Low Electricity Price Trend Scenario

Table 8D.2.24 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, Low Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	1.3%	1.3%	1.3%	1.6%	2.1%	3.1%	54.7%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	98.7%	98.7%	98.7%	98.4%	97.9%	96.9%	45.3%
Mean LCC Savings ($)	1592	1592	1592	1660	1868	2073	48
Median LCC Savings ($)	1495	1495	1495	1564	1747	1949	-140

Table 8D.2.25 Summary Payback Period Results for Design Line 7 Representative Unit, Low Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.8	4.8	4.8	5.0	6.1	7.2	19.0
Median Payback (Years)	4.6	4.6	4.6	4.9	6.0	7.1	18.6
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	218	218	218	210	184	151	129
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	118	118	118	125	152	185	207
Payback of Average Transformer	4.5	4.5	4.5	4.7	5.7	6.8	17.7

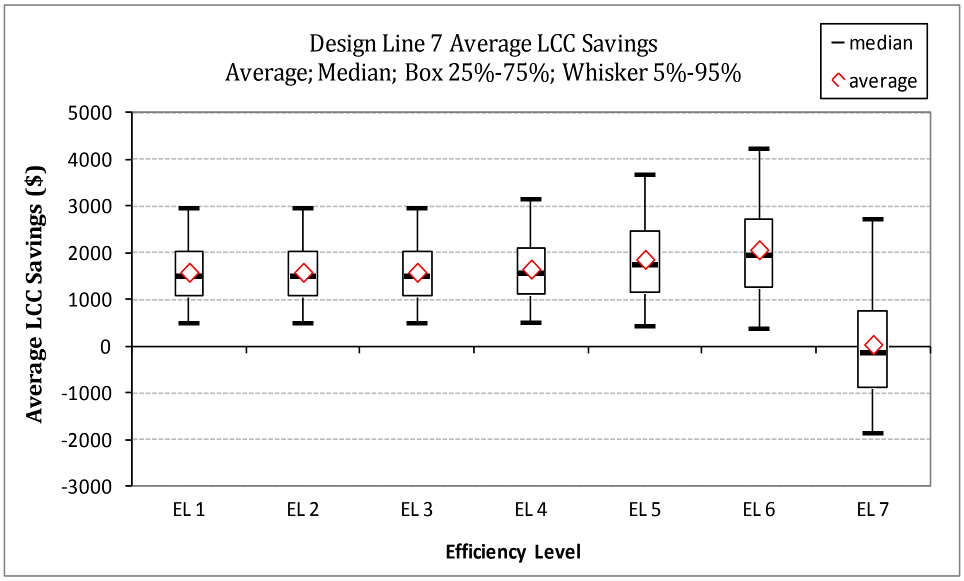

Figure 8D.2.24 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, Low Electricity Price Trend Scenario

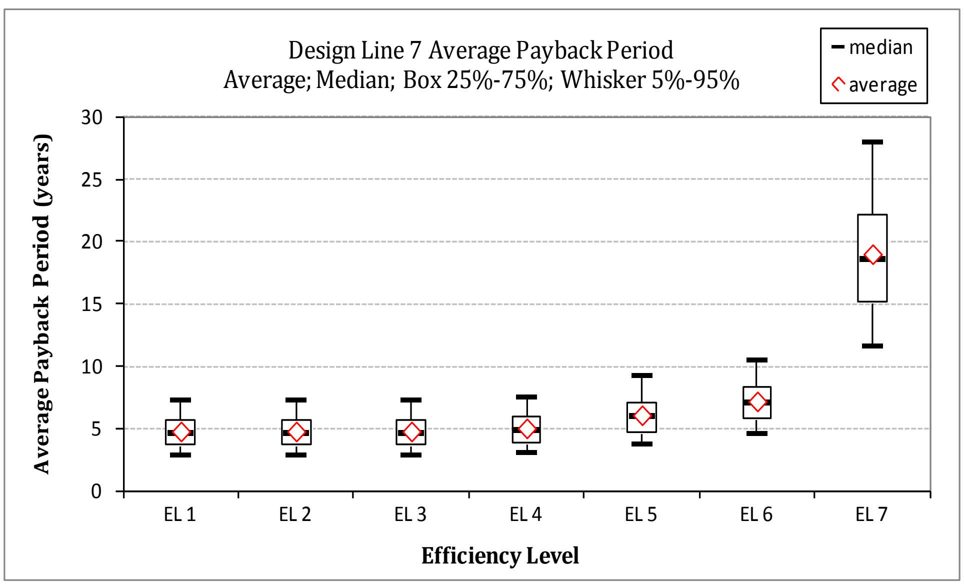

Figure 8D.2.25 Average Payback Period for Design Line 7 Representative Unit, Low Electricity Price Trend Scenario

8D.2.27 Design Line 7 Results, High Electricity Price Trend Scenario

Table 8D.2.26 Summary Life-Cycle Cost Results for Design Line 7 Representative Unit, High Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	98.23%	98.47%	98.60%	98.80%	98.93%	99.17%	99.44%
Transformers with Net LCC Cost (%)	0.8%	0.8%	0.8%	1.2%	1.9%	2.4%	36.3%
Transformers with No Change in LCC (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transformers with Net LCC Benefit (%)	99.2%	99.2%	99.2%	98.8%	98.1%	97.6%	63.7%
Mean LCC Savings ($)	1957	1957	1957	2048	2338	2644	685
Median LCC Savings ($)	1865	1865	1865	1952	2207	2496	481

Table 8D.2.27 Summary Payback Period Results for Design Line 7 Representative Unit, High Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	4.5	4.5	4.5	4.7	5.7	6.7	17.7
Median Payback (Years)	4.3	4.3	4.3	4.6	5.6	6.6	17.5
Transformers having Well Defined Payback (%)	100%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0%	0%	0%	0%	0%	0%	0%
Mean Retail Cost ($)	3,536	3,536	3,536	3,581	3,880	4,160	6,047
Mean Installation Cost ($)	1,743	1,743	1,743	1,761	1,732	1,839	2,362
Mean Operating Costs ($)	229	229	229	222	193	158	134
Mean Incremental First Cost ($)	530	530	530	593	863	1,250	3,660
Mean Operating Cost Savings ($)	127	127	127	135	163	198	222
Payback of Average Transformer	4.2	4.2	4.2	4.4	5.3	6.3	16.5

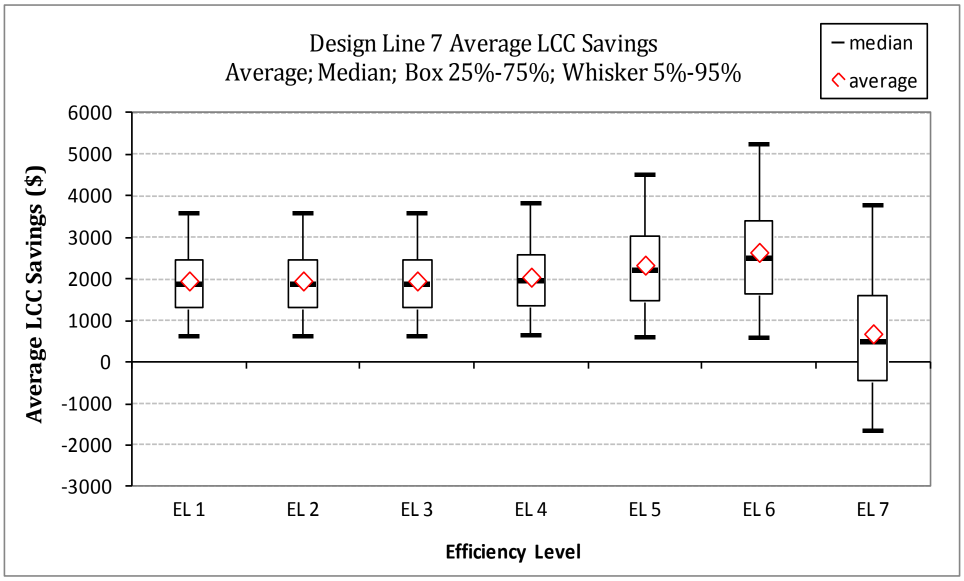

Figure 8D.2.26 Average Life-Cycle Cost Savings for Design Line 7 Representative Unit, High Electricity Price Trend Scenario

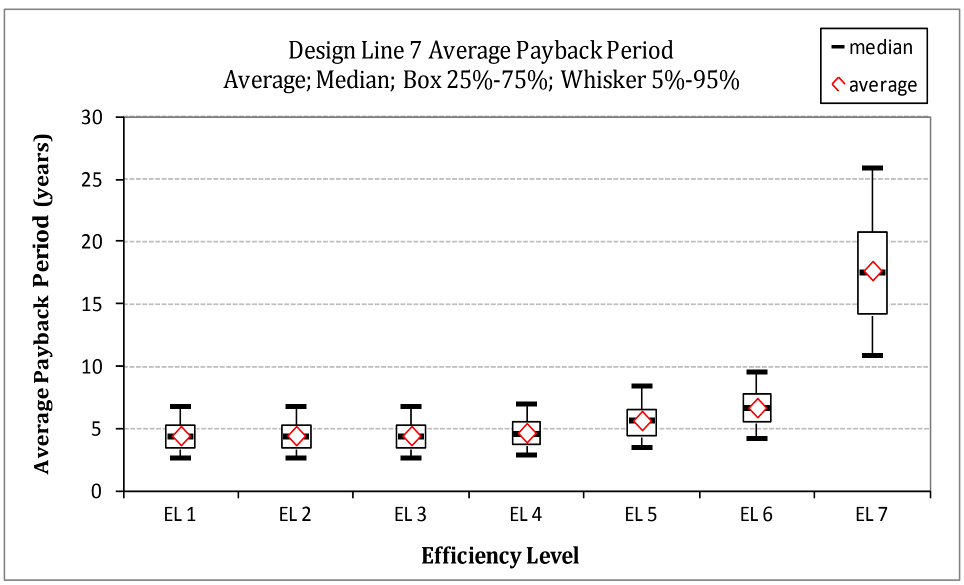

Figure 8D.2.27 Average Payback Period for Design Line 7 Representative Unit, High Electricity Price Trend Scenario

8D.3 DESIGN LINE 12 RESULTS

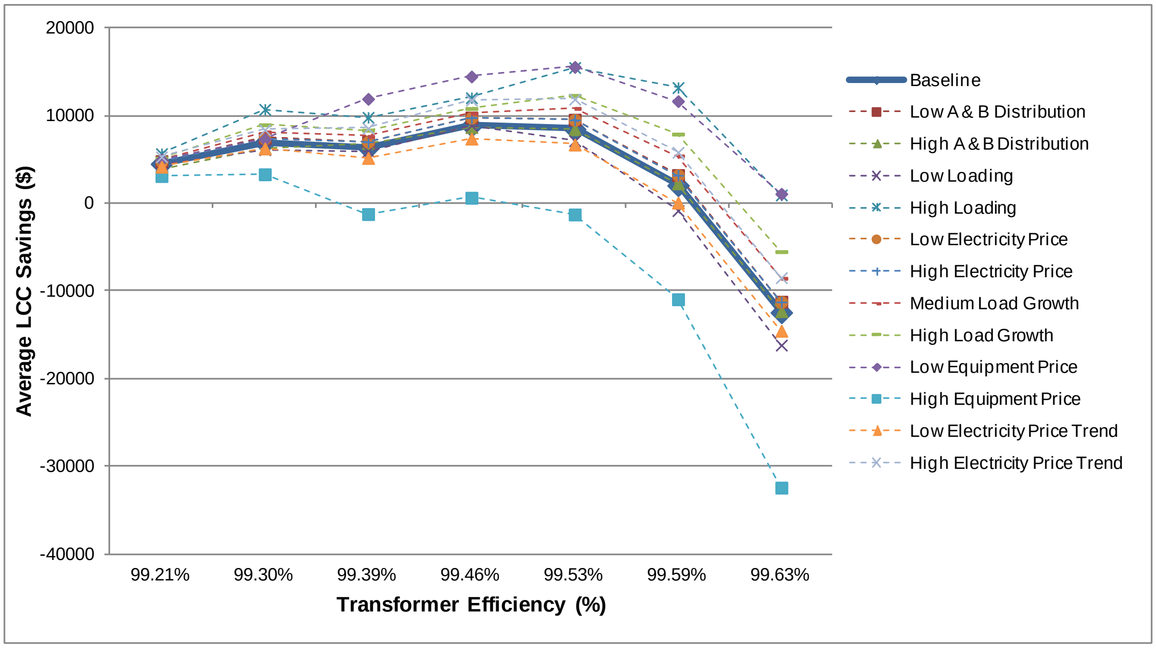

Figure 8D.3.1 Average LCC Savings ($) by Scenario for Design Line 12

Table 8D.3.1 LCC Savings ($), Summary Table for Design Line 12

Scenario	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Baseline	4518	6934	6332	8860	8475	2063	-12420
Low A & B Distribution	4825	7460	7048	9801	9552	3241	-11194
High A & B Distribution	3955	6288	6883	8709	8453	2289	-12277
Low Loading	4496	6138	5975	8907	7146	-806	-16139
High Loading	5674	10729	9815	12054	15498	13214	967
Low Electricity Price	4801	7431	7022	9775	9524	3214	-11221
High Electricity Price	4801	7431	7022	9775	9524	3214	-11221
Medium Load Growth	4984	8156	7649	10270	10839	5422	-8528
High Load Growth	5188	8971	8355	10826	12322	7913	-5487
Low Equipment Price	5021	7317	11925	14475	15571	11667	1108
High Equipment Price	3128	3328	-1206	653	-1253	-10916	-32389
Low Electricity Price Trend	4191	6280	5191	7396	6714	100	-14508
High Electricity Price Trend	5313	8399	8561	11775	11889	5834	-8457

8D.3.28 Design Line 12 Results, Baseline Scenario

Table 8D.3.2 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Baseline Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	6.72%	7.76%	23.46%	18.12%	25.10%	48.09%	81.09%
Transformers with No Change in LCC (%)	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	93.27%	92.24%	76.54%	81.88%	74.90%	51.91%	18.91%
Mean LCC Savings ($)	4518	6934	6332	8860	8475	2063	-12420
Median LCC Savings ($)	4178	6402	5356	8003	7400	642	-14191

Table 8D.3.3 Summary Payback Period Results for Design Line 12 Representative Unit, Baseline Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.5	9.6	14.4	13.3	14.6	19.0	27.1
Median Payback (Years)	6.3	9.0	13.5	13.0	14.1	18.2	25.9
Transformers having Well Defined Payback (%)	99.29%	100%	99.99%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.71%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,380	60,978	68,566	71,895	76,909	86,085	101,590
Mean Installation Cost ($)	7,113	7,231	7,971	8,316	8,637	9,318	10,270
Mean Operating Costs ($)	2,976	2,645	2,228	1,894	1,627	1,441	1,335
Mean Incremental First Cost ($)	2,326	6,042	14,370	18,045	23,379	33,236	49,694
Mean Operating Cost Savings ($)	370	701	1,118	1,452	1,719	1,905	2,011
Payback of Average Transformer	6.3	8.6	12.9	12.4	13.6	17.4	24.7

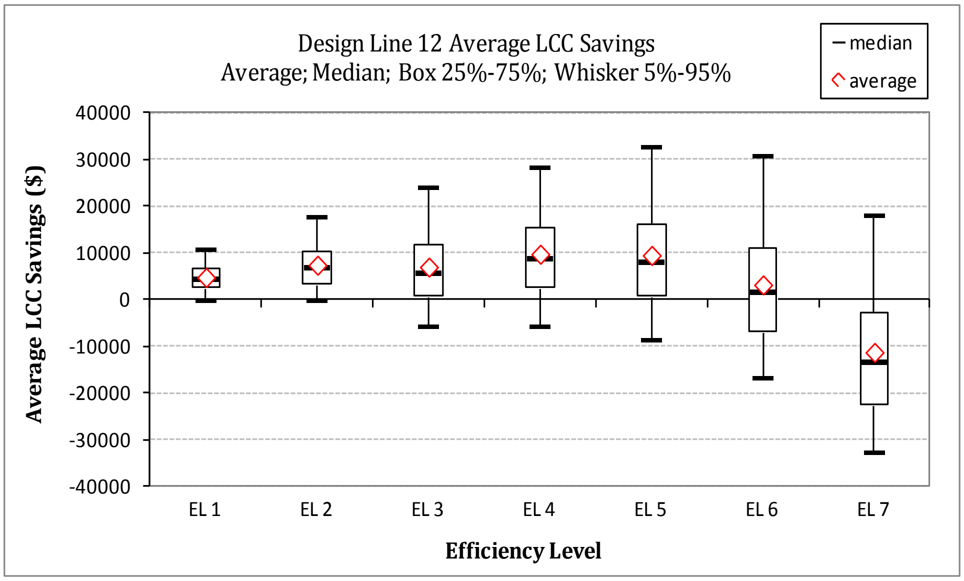

Figure 8D.3.2 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Baseline Scenario

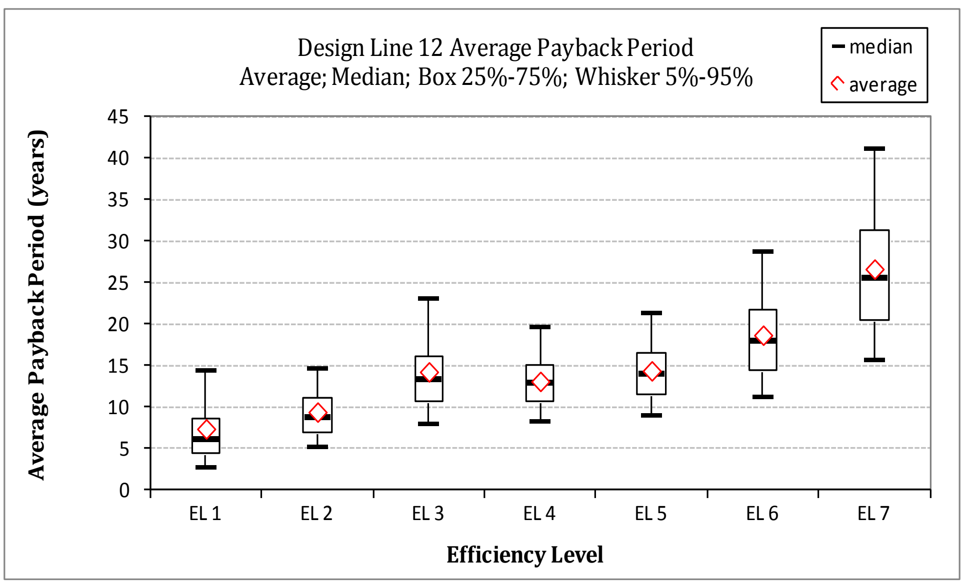

Figure 8D.3.3 Average Payback Period for Design Line 12 Representative Unit, Baseline Scenario

8D.3.29 Design Line 12 Results, Low A & B Distribution Scenario

Table 8D.3.4 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Low A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.90%	5.80%	21.30%	16.10%	22.70%	45.20%	79.70%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	94.10%	94.20%	78.70%	83.90%	77.30%	54.80%	20.30%
Mean LCC Savings ($)	4825	7460	7048	9801	9552	3241	-11194
Median LCC Savings ($)	4399	6812	5745	8709	8086	1530	-13394

Table 8D.3.5 Summary Payback Period Results for Design Line 12 Representative Unit, Low A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.4	9.4	14.3	13.1	14.4	18.7	26.6
Median Payback (Years)	6.1	8.7	13.3	13.0	14.0	17.9	25.5
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,351	60,944	68,547	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,230	7,968	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,013	2,676	2,256	1,916	1,646	1,458	1,351
Mean Incremental First Cost ($)	2,340	6,052	14,394	18,072	23,393	33,258	49,712
Mean Operating Cost Savings ($)	379	715	1,135	1,476	1,745	1,933	2,040
Payback of Average Transformer	6.2	8.5	12.7	12.2	13.4	17.2	24.4

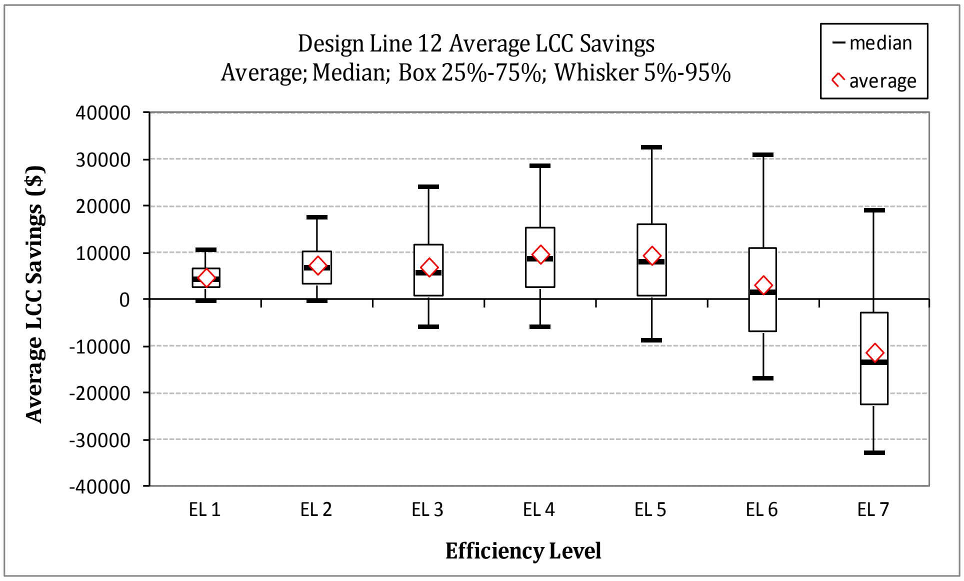

Figure 8D.3.4 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Low A & B Distribution Scenario

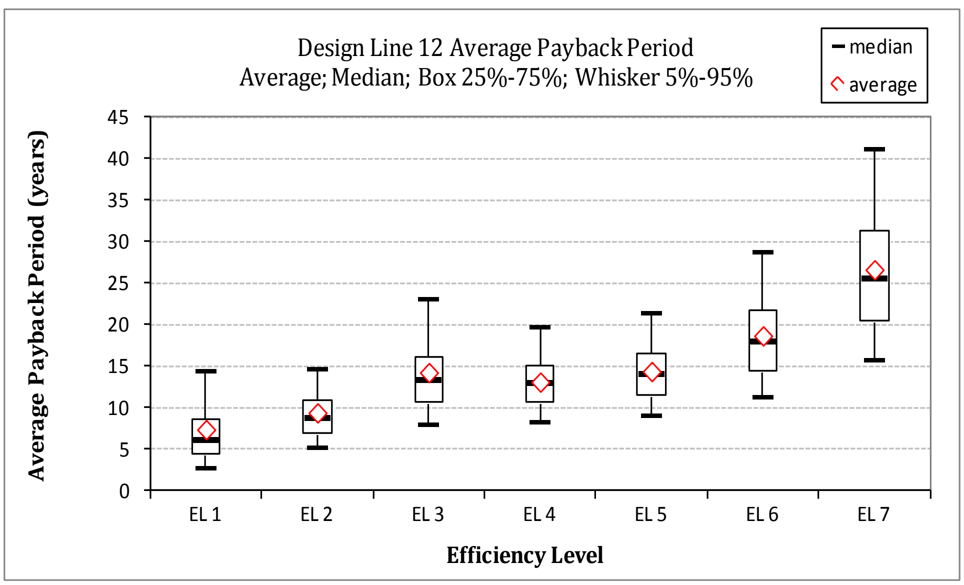

Figure 8D.3.5 Average Payback Period for Design Line 12 Representative Unit, Low A & B Distribution Scenario

8D.3.30 Design Line 12 Results, High A & B Distribution Scenario

Table 8D.3.6 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, High A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	12.50%	13.90%	19.10%	19.20%	26.80%	49.70%	80.40%
Transformers with No Change in LCC (%)	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	87.40%	86.10%	80.90%	80.80%	73.20%	50.30%	19.60%
Mean LCC Savings ($)	3955	6288	6883	8709	8453	2289	-12277
Median LCC Savings ($)	3257	5339	6108	7441	6838	493	-14786

Table 8D.3.7 Summary Payback Period Results for Design Line 12 Representative Unit, High A & B Distribution Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	9.6	11.7	13.8	13.6	15.0	19.7	28.4
Median Payback (Years)	6.9	9.8	13.5	13.3	14.6	18.6	26.4
Transformers having Well Defined Payback (%)	97.20%	99.80%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	2.80%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,567	61,299	69,261	71,884	76,897	85,993	101,56 5
Mean Installation Cost ($)	7,086	7,280	8,140	8,317	8,638	9,308	10,271
Mean Operating Costs ($)	2,991	2,659	2,160	1,915	1,646	1,455	1,351
Mean Incremental First Cost ($)	2,026	5,951	14,774	17,574	22,907	32,674	49,208
Mean Operating Cost Savings ($)	317	649	1,147	1,392	1,662	1,852	1,957
Payback of Average Transformer	6.4	9.2	12.9	12.6	13.8	17.6	25.1

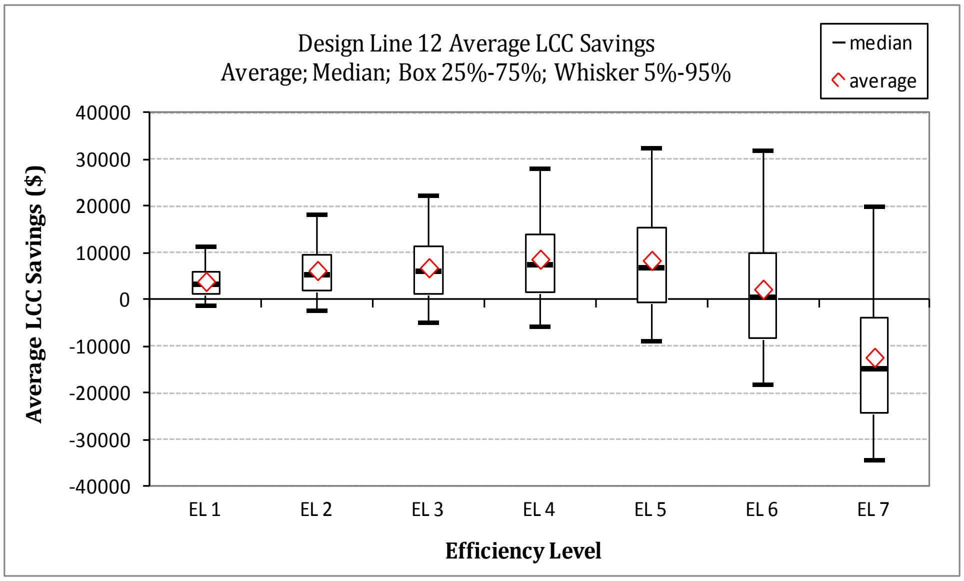

Figure 8D.3.6 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, High A & B Distribution Scenario

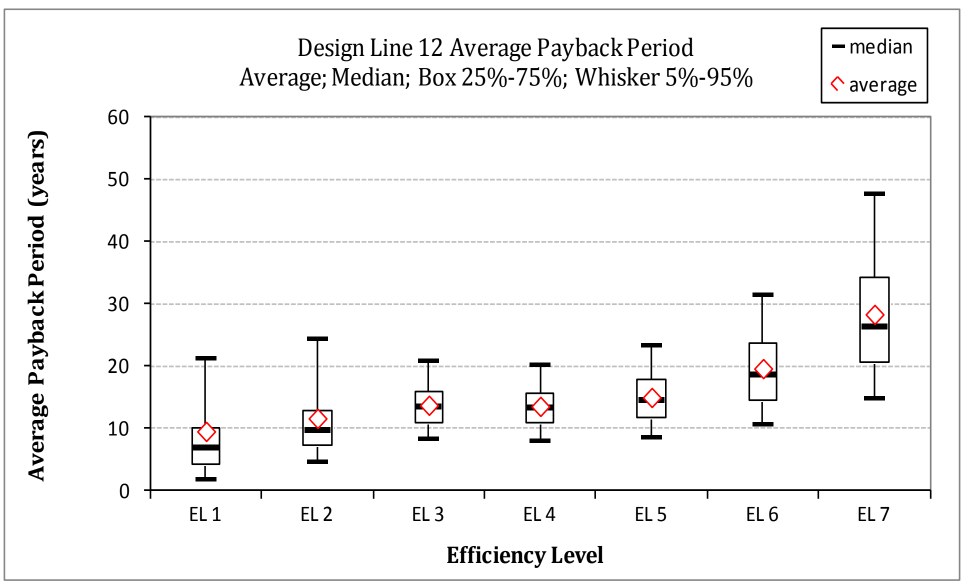

Figure 8D.3.7 Average Payback Period for Design Line 12 Representative Unit, High A & B Distribution Scenario

8D.3.31 Design Line 12 Results, Low Loading Scenario

Table 8D.3.8 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Low Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	7.70%	8.60%	24.80%	18.30%	26.60%	58.80%	88.50%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	92.30%	91.40%	75.20%	81.70%	73.40%	41.20%	11.50%
Mean LCC Savings ($)	4496	6138	5975	8907	7146	-806	-16139
Median LCC Savings ($)	4239	5535	4548	7953	5668	-2736	-17914

Table 8D.3.9 Summary Payback Period Results for Design Line 12 Representative Unit, Low Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	8.1	10.6	15.4	13.6	15.5	20.9	30.4
Median Payback (Years)	6.5	9.7	13.9	13.4	15.2	20.3	29.3
Transformers having Well Defined Payback (%)	99.00%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	2,658	2,373	1,939	1,590	1,401	1,299	1,240
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	362	646	1,081	1,429	1,619	1,720	1,780
Payback of Average Transformer	6.4	9.4	13.3	12.6	14.4	19.3	27.9

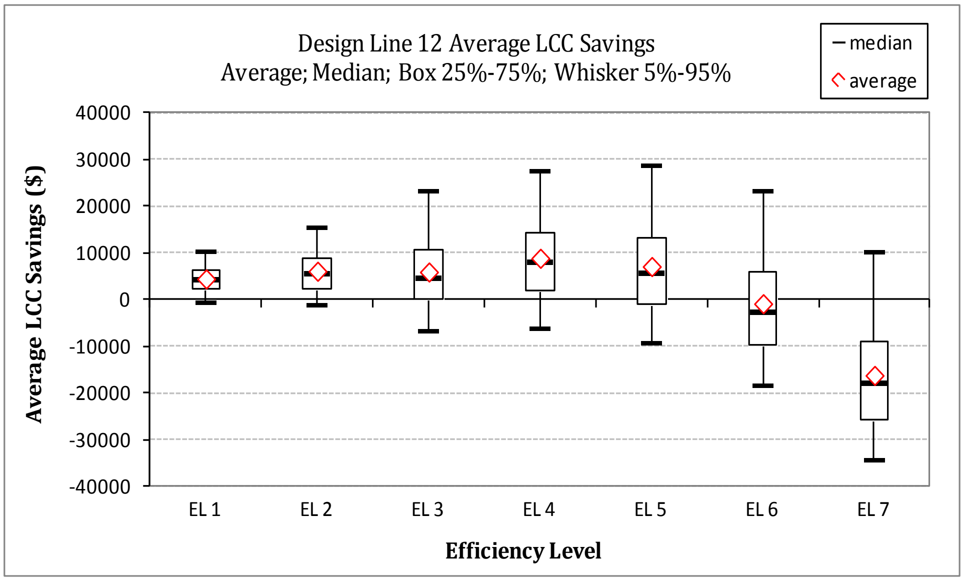

Figure 8D.3.8 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Low Loading Scenario

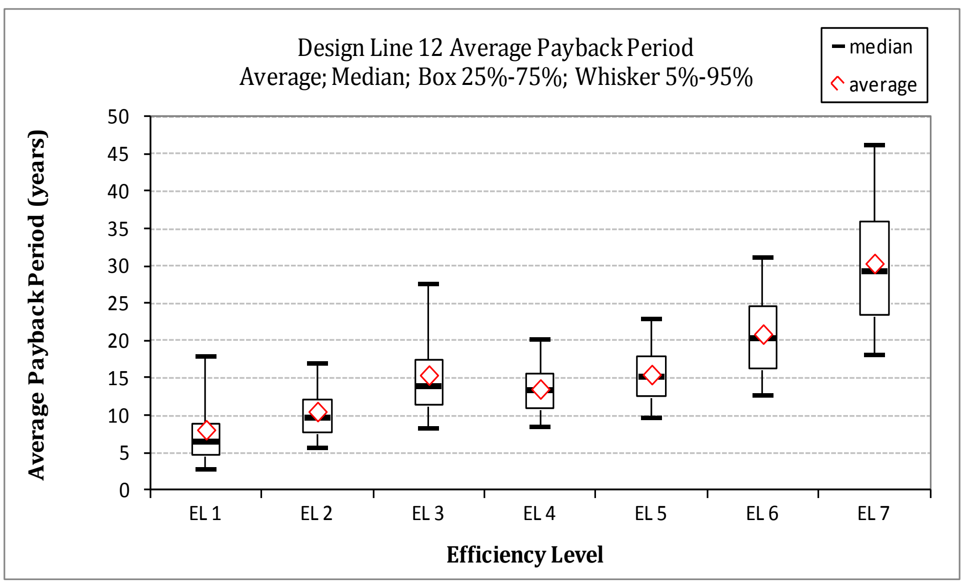

Figure 8D.3.9 Average Payback Period for Design Line 12 Representative Unit, Low Loading Scenario

8D.3.32 Design Line 12 Results, High Loading Scenario

Table 8D.3.10 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, High Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.00%	3.30%	17.10%	12.70%	14.20%	26.70%	57.50%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	95.00%	96.70%	82.90%	87.30%	85.80%	73.30%	42.50%
Mean LCC Savings ($)	5674	10729	9815	12054	15498	13214	967
Median LCC Savings ($)	4864	9199	7399	10720	13039	9928	-2989

Table 8D.3.11 Summary Payback Period Results for Design Line 12 Representative Unit, High Loading Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	6.9	7.7	12.9	12.2	12.4	15.1	20.9
Median Payback (Years)	5.6	7.3	12.4	12.1	12.1	14.6	20.0
Transformers having Well Defined Payback (%)	99.50%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,887	3,423	3,031	2,716	2,251	1,849	1,626
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	423	887	1,279	1,594	2,059	2,461	2,684
Payback of Average Transformer	5.5	6.8	11.3	11.3	11.4	13.5	18.5

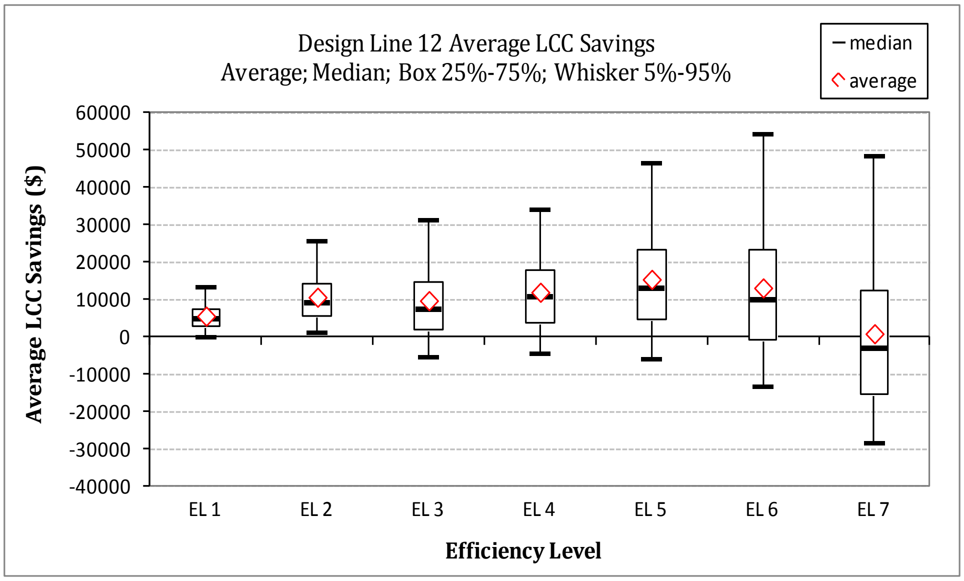

Figure 8D.3.10 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, High Loading Scenario

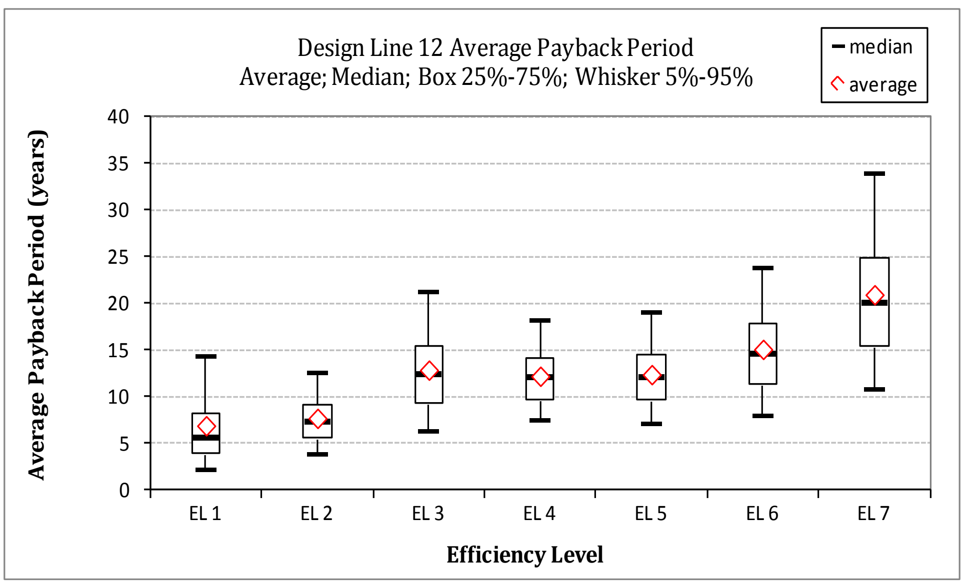

Figure 8D.3.11 Average Payback Period for Design Line 12 Representative Unit, High Loading Scenario

8D.3.33 Design Line 12 Results, Low Electricity Price Scenario

Table 8D.3.12 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Low Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.90%	5.80%	21.30%	16.10%	22.80%	45.40%	79.80%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	94.10%	94.20%	78.70%	83.90%	77.20%	54.60%	20.20%
Mean LCC Savings ($)	4801	7431	7022	9775	9524	3214	-11221
Median LCC Savings ($)	4383	6807	5687	8700	8012	1530	-13394

Table 8D.3.13 Summary Payback Period Results for Design Line 12 Representative Unit, Low Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.4	9.4	14.3	13.1	14.4	18.7	26.7
Median Payback (Years)	6.1	8.8	13.3	13.0	14.0	18.0	25.5
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,012	2,676	2,255	1,916	1,646	1,458	1,351
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	377	714	1,134	1,474	1,743	1,932	2,039
Payback of Average Transformer	6.2	8.5	12.7	12.3	13.4	17.2	24.4

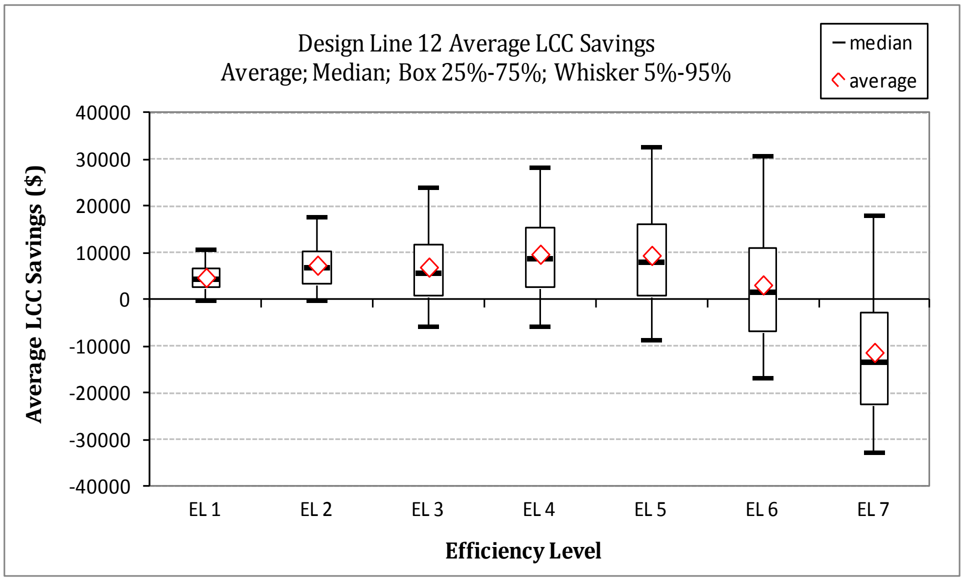

Figure 8D.3.12 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Low Electricity Price Scenario

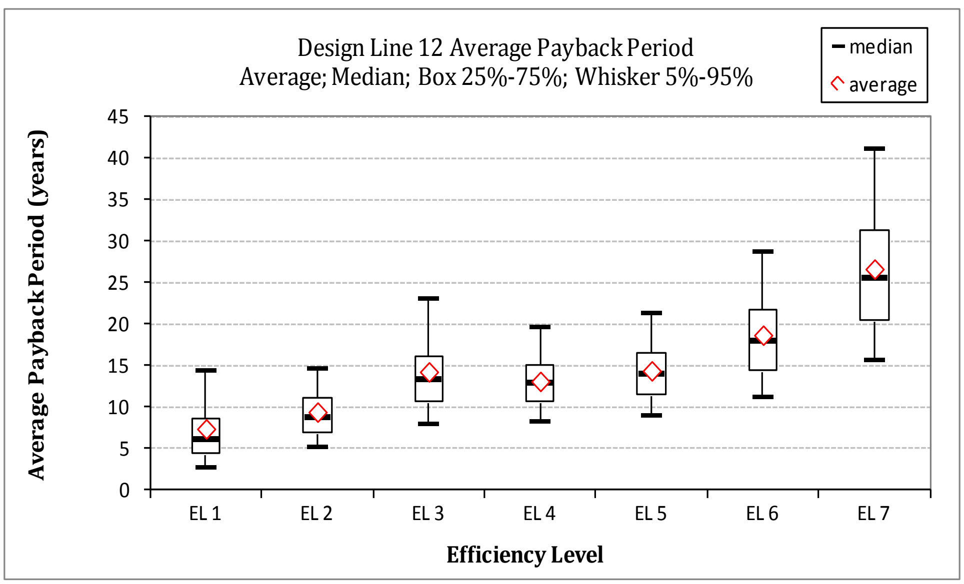

Figure 8D.3.13 Average Payback Period for Design Line 12 Representative Unit, Low Electricity Price Scenario

8D.3.34 Design Line 12 Results, High Electricity Price Scenario

Table 8D.3.14 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, High Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.90%	5.80%	21.30%	16.10%	22.80%	45.40%	79.80%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	94.10%	94.20%	78.70%	83.90%	77.20%	54.60%	20.20%
Mean LCC Savings ($)	4801	7431	7022	9775	9524	3214	-11221
Median LCC Savings ($)	4383	6807	5687	8700	8012	1530	-13394

Table 8D.3.15 Summary Payback Period Results for Design Line 12 Representative Unit, High Electricity Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.4	9.4	14.3	13.1	14.4	18.7	26.7
Median Payback (Years)	6.1	8.8	13.3	13.0	14.0	18.0	25.5
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,012	2,676	2,255	1,916	1,646	1,458	1,351
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	377	714	1,134	1,474	1,743	1,932	2,039
Payback of Average Transformer	6.2	8.5	12.7	12.3	13.4	17.2	24.4

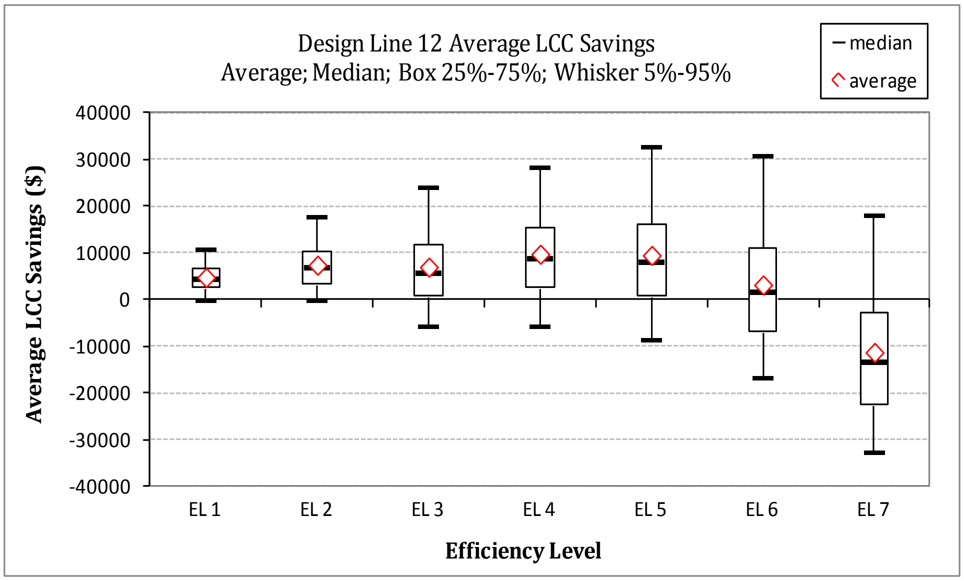

Figure 8D.3.14 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, High Electricity Price Scenario

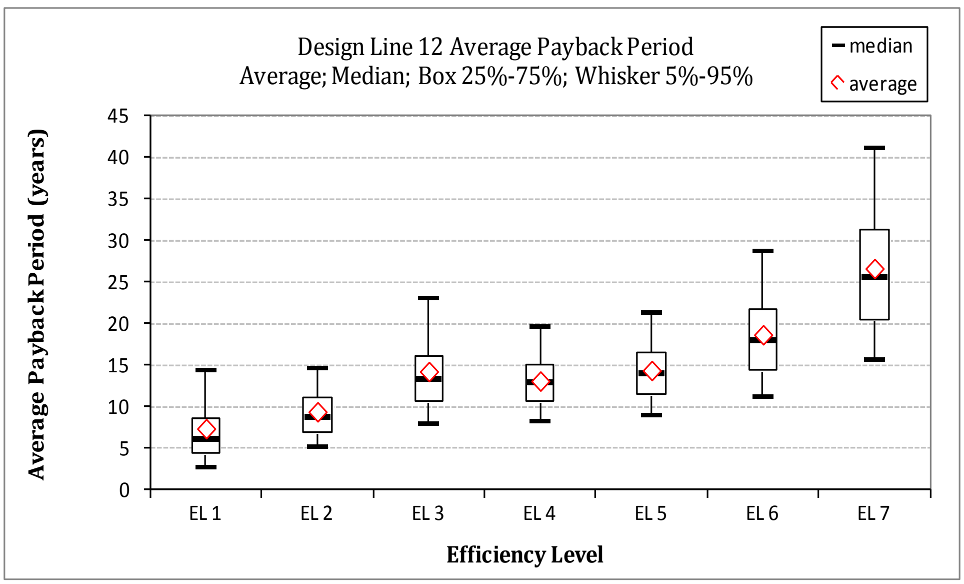

Figure 8D.3.15 Average Payback Period for Design Line 12 Representative Unit, High Electricity Price Scenario

8D.3.35 Design Line 12 Results, Medium Load Growth Scenario

Table 8D.3.16 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Medium Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.20%	4.90%	19.80%	15.20%	20.80%	40.70%	73.40%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	94.80%	95.10%	80.20%	84.80%	79.20%	59.30%	26.60%
Mean LCC Savings ($)	4984	8156	7649	10270	10839	5422	-8528
Median LCC Savings ($)	4532	7419	6088	9288	9359	3374	-11090

Table 8D.3.17 Summary Payback Period Results for Design Line 12 Representative Unit, Medium Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.4	9.4	14.3	13.1	14.4	18.7	26.7
Median Payback (Years)	6.1	8.8	13.3	13.0	14.0	18.0	25.5
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,012	2,676	2,255	1,916	1,646	1,458	1,351
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	377	714	1,134	1,474	1,743	1,932	2,039
Payback of Average Transformer	6.2	8.5	12.7	12.3	13.4	17.2	24.4

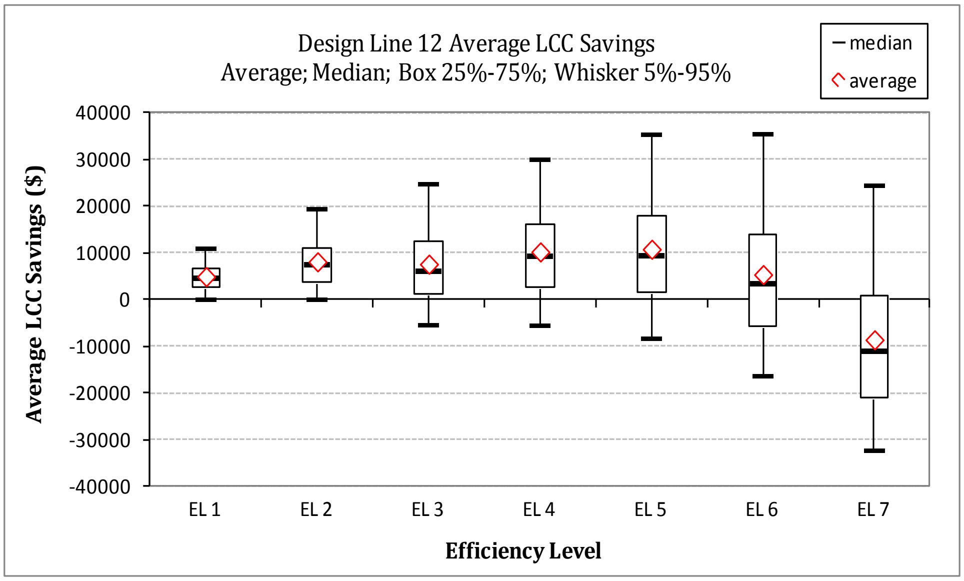

Figure 8D.3.16 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Medium Load Growth Scenario

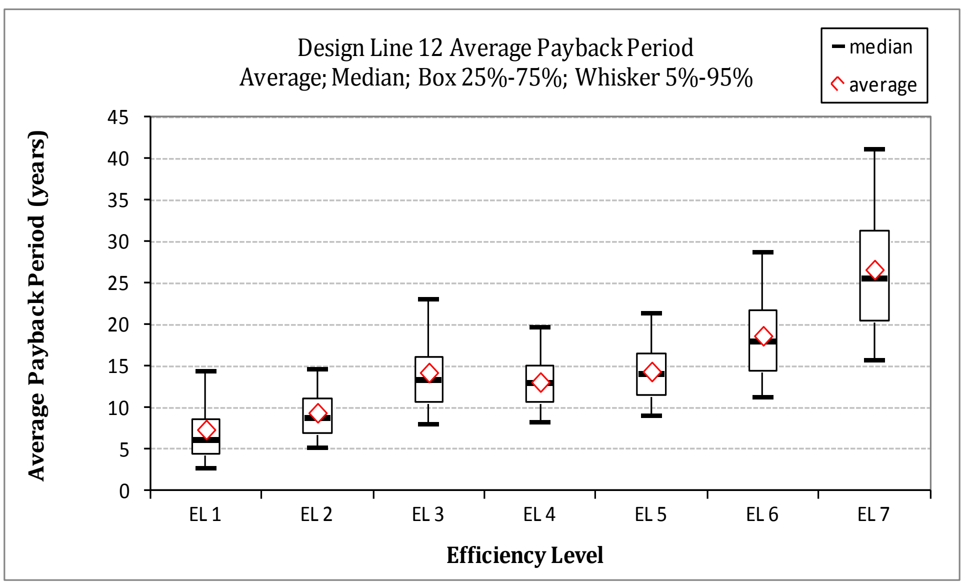

Figure 8D.3.17 Average Payback Period for Design Line 12 Representative Unit, Medium Load Growth Scenario

8D.3.36 Design Line 12 Results, High Load Growth Scenario

Table 8D.3.18 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, High Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.40%	4.20%	19.40%	14.50%	18.40%	36.30%	67.00%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	94.60%	95.80%	80.60%	85.50%	81.60%	63.70%	33.00%
Mean LCC Savings ($)	5188	8971	8355	10826	12322	7913	-5487
Median LCC Savings ($)	4645	7929	6545	9787	10600	5693	-8208

Table 8D.3.19 Summary Payback Period Results for Design Line 12 Representative Unit, High Load Growth Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.4	9.4	14.3	13.1	14.4	18.7	26.7
Median Payback (Years)	6.1	8.8	13.3	13.0	14.0	18.0	25.5
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,012	2,676	2,255	1,916	1,646	1,458	1,351
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	377	714	1,134	1,474	1,743	1,932	2,039
Payback of Average Transformer	6.2	8.5	12.7	12.3	13.4	17.2	24.4

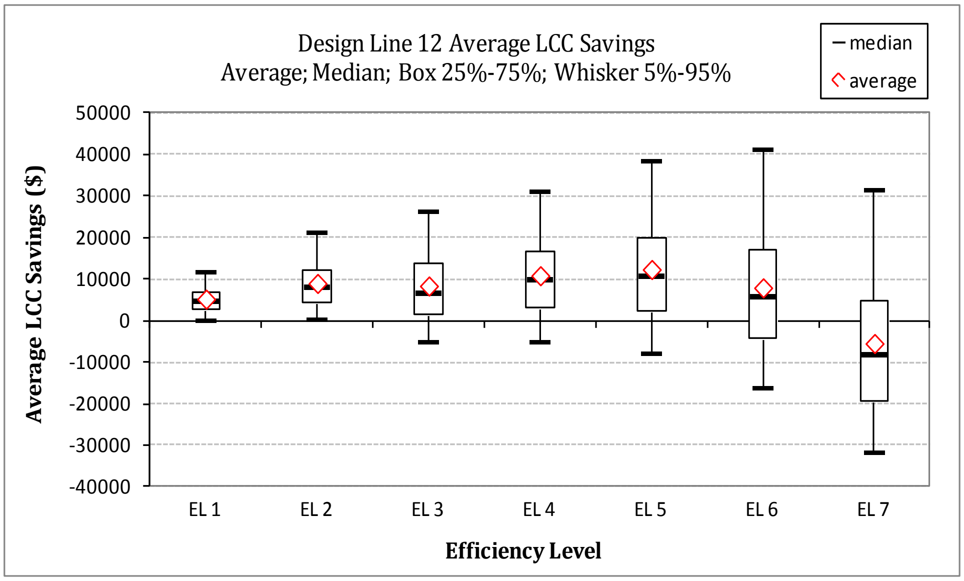

Figure 8D.3.18 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, High Load Growth Scenario

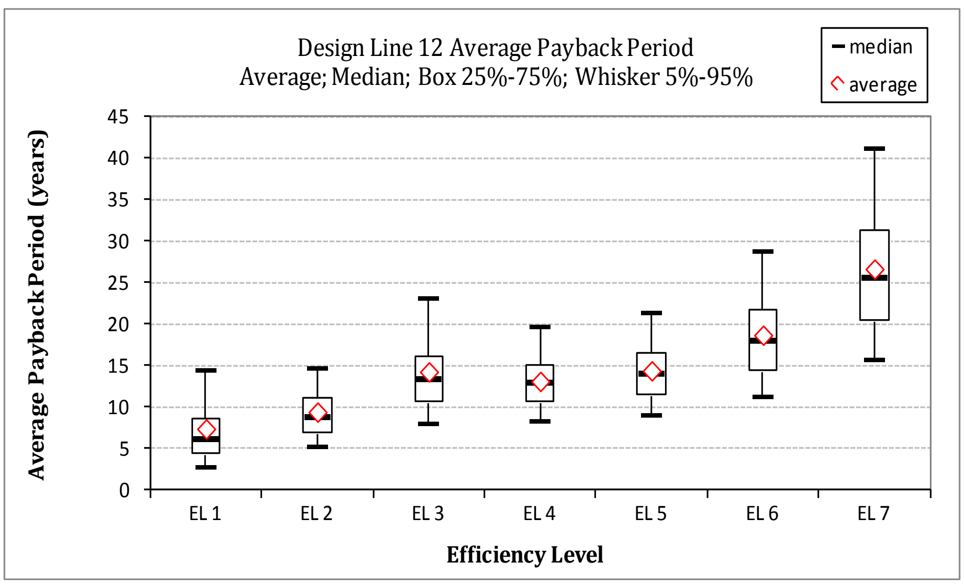

Figure 8D.3.19 Average Payback Period for Design Line 12 Representative Unit, High Load Growth Scenario

8D.3.37 Design Line 12 Results, Low Equipment Price Scenario

Table 8D.3.20 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Low Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	4.30%	6.30%	5.40%	5.00%	7.00%	20.50%	52.00%
Transformers with No Change in LCC (%)	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	95.50%	93.70%	94.60%	95.00%	93.00%	79.50%	48.00%
Mean LCC Savings ($)	5021	7317	11925	14475	15571	11667	1108
Median LCC Savings ($)	4801	6756	10725	13227	14099	10159	-824

Table 8D.3.21 Summary Payback Period Results for Design Line 12 Representative Unit, Low Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	5.1	9.0	9.4	9.3	10.4	13.8	20.1
Median Payback (Years)	3.9	8.0	9.3	9.2	10.2	13.3	19.3
Transformers having Well Defined Payback (%)	98.20%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	1.80%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	45,002	48,728	53,104	55,018	58,671	65,477	77,064
Mean Installation Cost ($)	7,235	7,329	8,141	8,317	8,637	9,313	10,272
Mean Operating Costs ($)	3,004	2,680	2,161	1,915	1,646	1,457	1,351
Mean Incremental First Cost ($)	1,315	5,134	10,323	12,412	16,385	23,867	36,414
Mean Operating Cost Savings ($)	335	659	1,178	1,424	1,693	1,883	1,988
Payback of Average Transformer	3.9	7.8	8.8	8.7	9.7	12.7	18.3

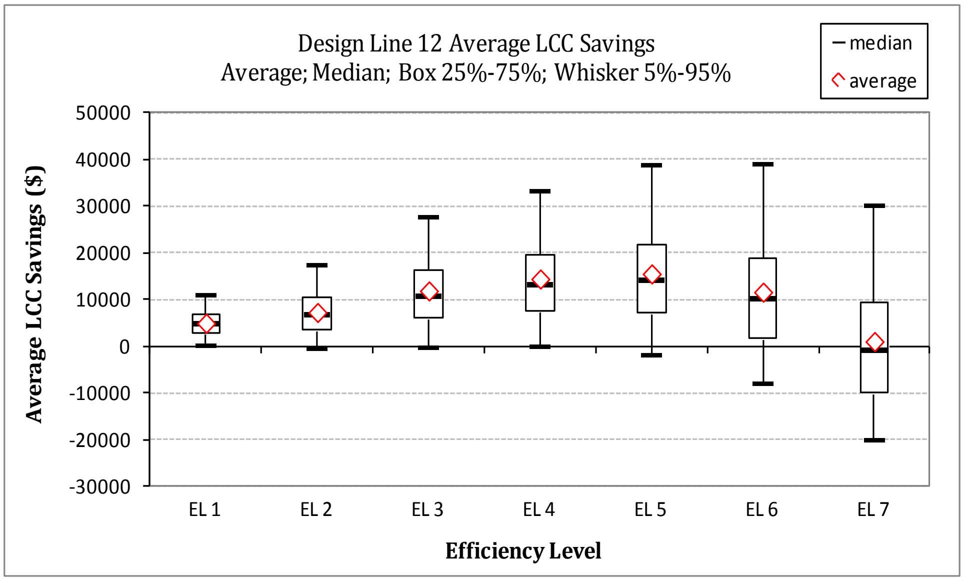

Figure 8D.3.20 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Low Equipment Price Scenario

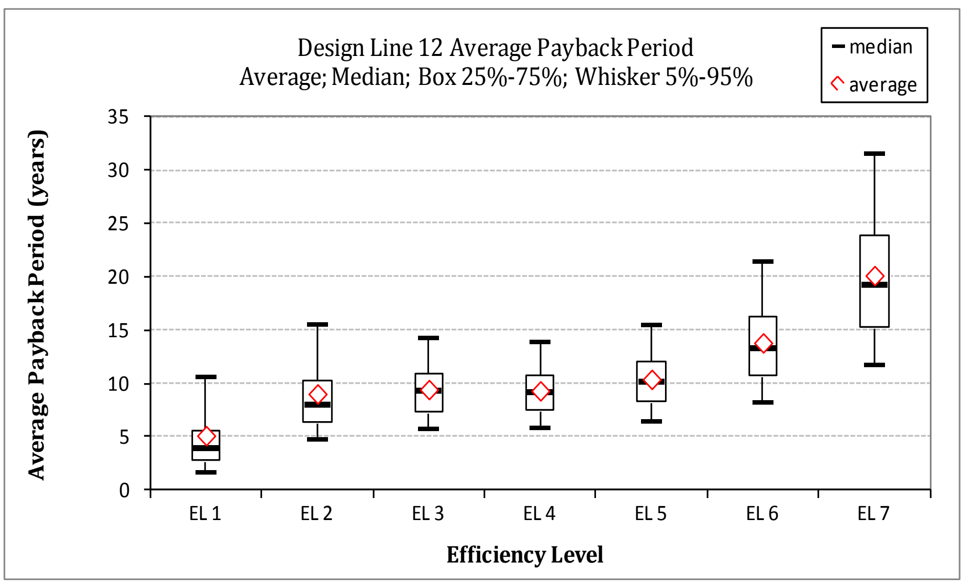

Figure 8D.3.21 Average Payback Period for Design Line 12 Representative Unit, Low Equipment Price Scenario

8D.3.38 Design Line 12 Results, High Equipment Price Scenario

Table 8D.3.22 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, High Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	13.50%	26.30%	62.10%	50.90%	59.20%	81.10%	95.90%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	86.50%	73.70%	37.90%	49.10%	40.80%	18.90%	4.10%
Mean LCC Savings ($)	3128	3328	-1206	653	-1253	-10916	-32389
Median LCC Savings ($)	2832	2700	-2350	-198	-2469	-12447	-34413

Table 8D.3.23 Summary Payback Period Results for Design Line 12 Representative Unit, High Equipment Price Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	12.2	15.3	21.9	19.7	20.9	26.4	37.6
Median Payback (Years)	11.1	14.8	21.1	19.5	20.4	25.5	36.4
Transformers having Well Defined Payback (%)	99.80%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	75,993	82,223	92,836	98,163	104,811	117,567	139,895
Mean Installation Cost ($)	7,222	7,226	7,832	8,316	8,634	9,288	10,269
Mean Operating Costs ($)	3,017	2,676	2,321	1,916	1,647	1,449	1,351
Mean Incremental First Cost ($)	4,131	10,365	21,584	27,395	34,361	47,771	71,080
Mean Operating Cost Savings ($)	385	726	1,081	1,486	1,755	1,953	2,050
Payback of Average Transformer	10.7	14.3	20.0	18.4	19.6	24.5	34.7

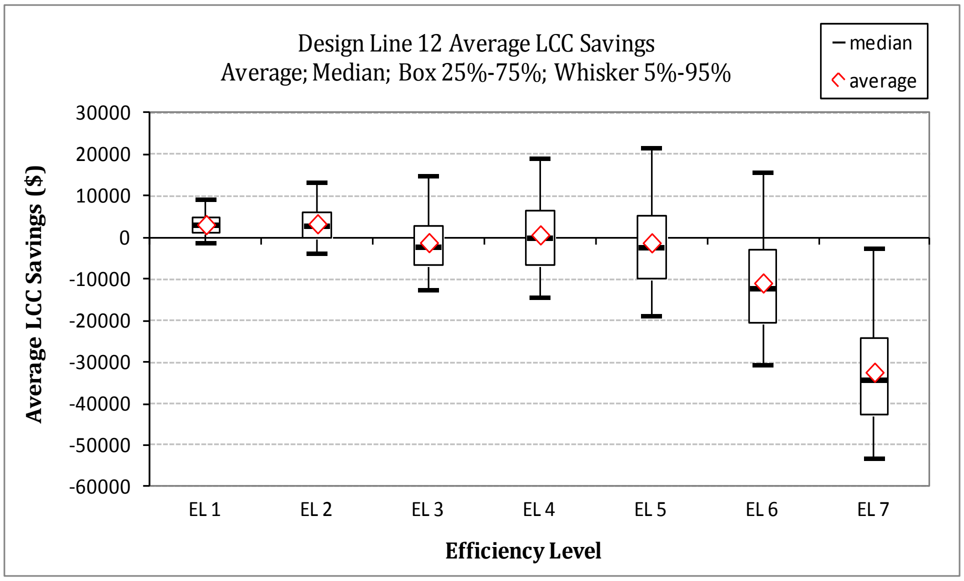

Figure 8D.3.22 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, High Equipment Price Scenario

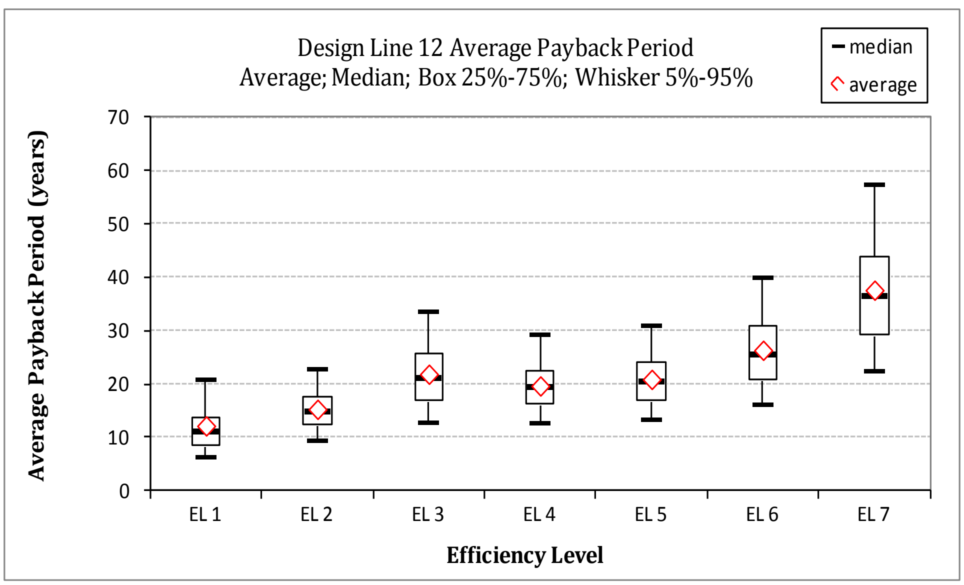

Figure 8D.3.23 Average Payback Period for Design Line 12 Representative Unit, High Equipment Price Scenario

8D.3.39 Design Line 12 Results, Low Electricity Price Trend Scenario

Table 8D.3.24 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, Low Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	6.60%	6.90%	27.10%	21.60%	27.60%	55.40%	85.80%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	93.40%	93.10%	72.90%	78.40%	72.40%	44.60%	14.20%
Mean LCC Savings ($)	4191	6280	5191	7396	6714	100	-14508
Median LCC Savings ($)	3789	5738	4051	6253	5284	-1609	-16638

Table 8D.3.25 Summary Payback Period Results for Design Line 12 Representative Unit, Low Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.7	9.8	14.8	13.6	15.0	19.4	27.7
Median Payback (Years)	6.4	9.1	13.9	13.5	14.6	18.6	26.6
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,56 3
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	2,896	2,573	2,169	1,843	1,584	1,403	1,300
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	363	686	1,090	1,416	1,675	1,856	1,959
Payback of Average Transformer	6.4	8.8	13.2	12.8	14.0	17.9	25.4

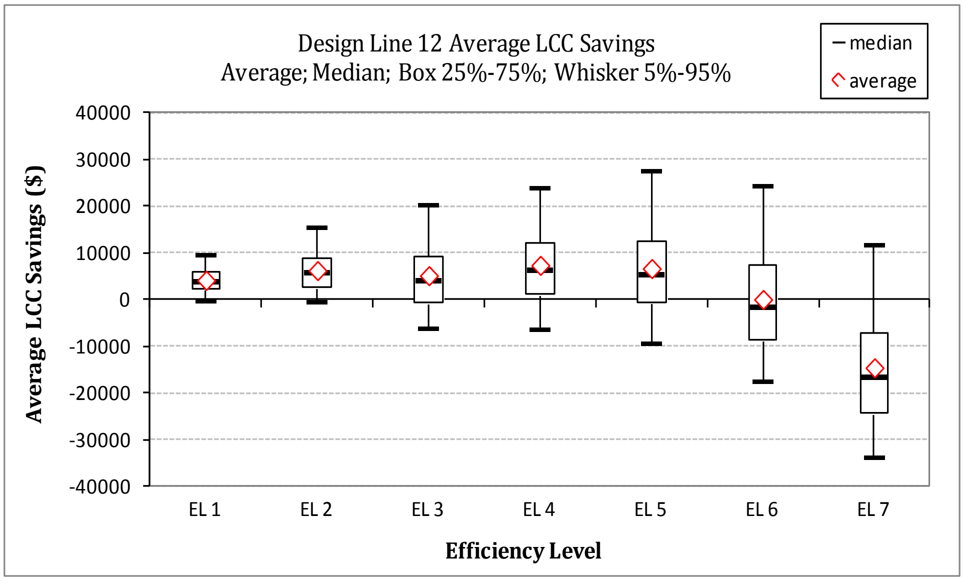

Figure 8D.3.24 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, Low Electricity Price Trend Scenario

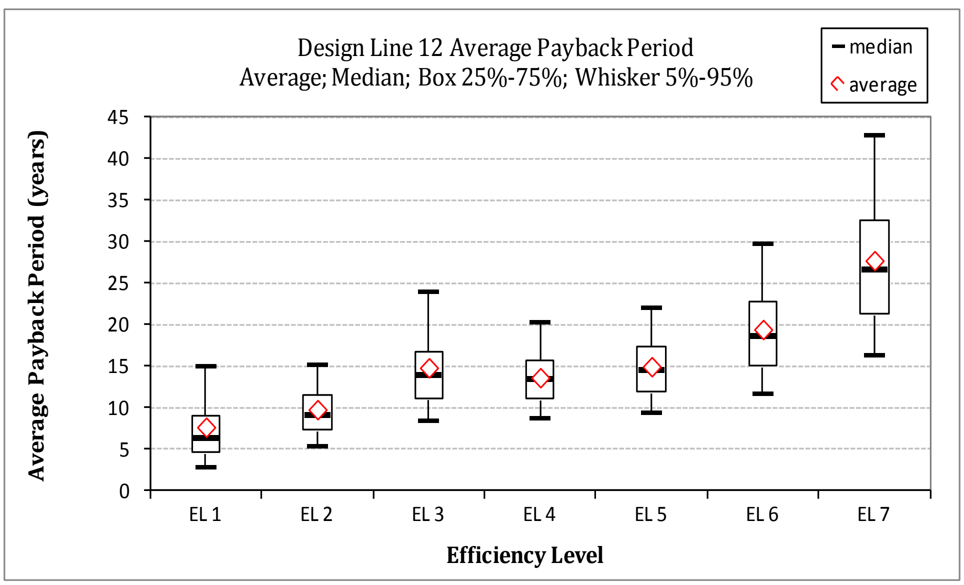

Figure 8D.3.25 Average Payback Period for Design Line 12 Representative Unit, Low Electricity Price Trend Scenario

8D.3.40 Design Line 12 Results, High Electricity Price Trend Scenario

Table 8D.3.26 Summary Life-Cycle Cost Results for Design Line 12 Representative Unit, High Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Efficiency (%)	99.21%	99.30%	99.39%	99.46%	99.53%	99.59%	99.63%
Transformers with Net LCC Cost (%)	5.00%	4.60%	17.40%	12.20%	18.20%	39.40%	73.60%
Transformers with No Change in LCC (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Transformers with Net LCC Benefit (%)	95.00%	95.40%	82.60%	87.80%	81.80%	60.60%	26.40%
Mean LCC Savings ($)	5313	8399	8561	11775	11889	5834	-8457
Median LCC Savings ($)	4867	7695	7089	10649	10297	4107	-10614

Table 8D.3.27 Summary Payback Period Results for Design Line 12 Representative Unit, High Electricity Price Trend Scenario

	Efficiency Level						
	1	2	3	4	5	6	7
Mean Payback (Years)	7.2	9.1	13.8	12.7	13.9	18.1	25.8
Median Payback (Years)	5.9	8.5	13.0	12.6	13.7	17.5	24.9
Transformers having Well Defined Payback (%)	99.30%	100%	100%	100%	100%	100%	100%
Transformers having Undefined Payback (%)	0.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean Retail Cost ($)	57,352	60,945	68,558	71,877	76,879	86,061	101,563
Mean Installation Cost ($)	7,111	7,229	7,971	8,316	8,636	9,318	10,270
Mean Operating Costs ($)	3,102	2,755	2,322	1,972	1,694	1,501	1,390
Mean Incremental First Cost ($)	2,332	6,043	14,398	18,062	23,383	33,248	49,703
Mean Operating Cost Savings ($)	389	735	1,169	1,519	1,796	1,990	2,100
Payback of Average Transformer	6.0	8.2	12.3	11.9	13.0	16.7	23.7

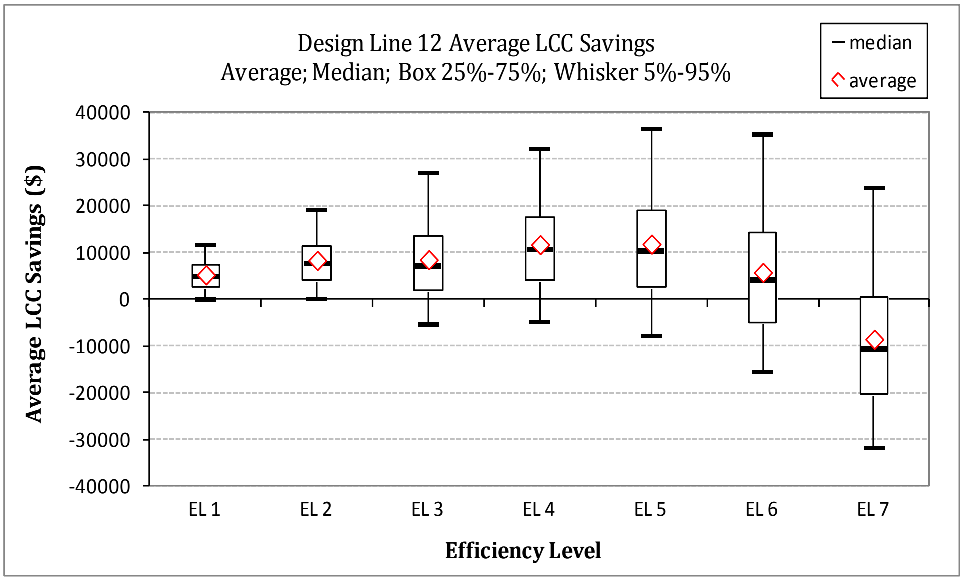

Figure 8D.3.26 Average Life-Cycle Cost Savings for Design Line 12 Representative Unit, High Electricity Price Trend Scenario

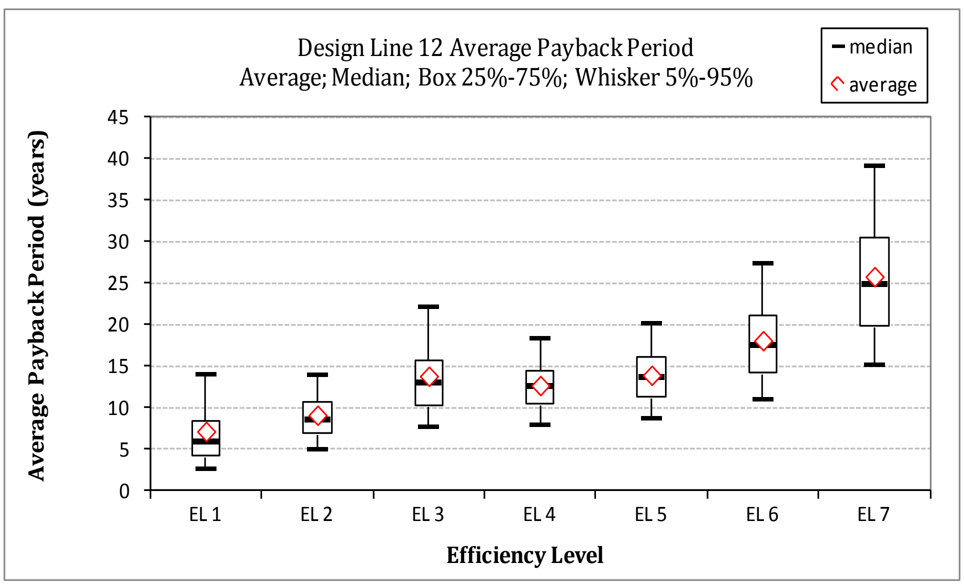

Figure 8D.3.27 Average Payback Period for Design Line 12 Representative Unit, High Electricity Price Trend Scenario

APPENDIX 10A. USER INSTRUCTIONS FOR SHIPMENTS AND NIA SPREADSHEET MODEL

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APPENDIX 10A. USER INSTRUCTIONS FOR SHIPMENTS AND NIA SPREADSHEET MODEL

10A.1 USER INSTRUCTIONS

The results obtained in the shipments analysis and the national impact analysis (NIA) can be examined and reproduced using the Microsoft Excel spreadsheet available on the U.S. Department of Energy (DOE)'s website at: http://www.eere.energy.gov/buildings/appliance_standards/commercial/dist_transformers.html.

The spreadsheet is called "NIA_DT_NOPR.xls," and it enables the user to perform a NIA of distribution transformer standards for both the liquid-immersed and dry-type equipment classes. This spreadsheet also enables the user to analyze the policy options considered in the regulatory impact analysis. To run the spreadsheet, the user needs to have Microsoft Excel 2000 or a later version.

10A.1.1 Worksheet Descriptions

The NIA spreadsheet performs calculations to forecast the changes in national energy savings (NES) and net present value (NPV) due to an energy efficiency standard. The energy use and associated costs for a given standard are determined first by calculating the shipments and then calculating the energy use and costs for a product class. The differences between the standards and base cases (absent a national standard) can then be compared and the NES and NPV determined. The NIA spreadsheet, or workbook, consists of the following 20 worksheets that are described below.

10A.1.1.1 Introduction

This worksheet provides an outline of the contents of the entire national impact spreadsheet and describes the calculations contained in individual worksheets.

10A.1.1.2 National Impact Summary

This worksheet contains user input selections and a summary table containing cumulative shipments, cumulative energy savings, and NPV for each candidate standard level (CSL). The worksheet also graphically summarizes the energy and economic savings resulting from standards.

10A.1.1.3 Summary Results

This worksheet provides a summary of the shipments forecast, national source energy savings, and the NPV of the savings for candidate standard levels (CSLs) for both the liquid-immersed and dry-type distribution transformers.

10A.1.1.4 Model Flowchart

This worksheet presents a flowchart of the shipments and the NES and NPV modules.

10A.1.1.5 Candidate Standard Level Definitions and Design-Lines-to-Product-Classes Mapping

This worksheet defines efficiency levels for the CSLs by design lines and provides design-lines-to-product-classes mapping.

10A.1.1.6 Ship-NES-NPV Output

This worksheet presents the consolidated outputs produced for each product class when the user clicks the button "All Classes Summary" on the "National Impact Summary" worksheet. Total savings and NPV for the forecast period are summarized in tables for each standard level.

10A.1.1.7 Energy Impacts from Candidate Standard Levels—Charts

This worksheet displays the savings charts for years 2015 through 2044 for all the CSLs when the user runs a specific scenario or a product class in the "National Impact Summary" sheet.

10A.1.1.8 Annual Impacts

This worksheet makes several calculations for the base case as well as for all the CSLs. Savings are calculated as the difference between the base case and the CSL energy consumption.

10A.1.1.9 Shipments Forecast across Candidate Standard Levels

This worksheet compiles the shipments forecast from the stock sheets (see below) for the years 2010 through 2038 for all the CSLs. The output of this worksheet corresponds to the product class for which the model is run.

10A.1.1.10Shipments Chart

This sheet contains the shipments model chart illustrating the forecast and backcast from the shipments model.

10A.1.1.11Shipments Data

This worksheet calculates total historical shipments for the years 1977 through 2009 and forecasts shipments for the years 2010 through 2044. These shipments are calculated for both liquid-immersed and dry-type transformers.

10A.1.1.12 Stock Sheets

There are two stock sheets—one for the base case and another for the standards case. Each stock sheet calculates the shipments, retirements, and affected stock in a particular year for liquid-immersed and dry-type transformers.

10A.1.1.13 Lifetime

This worksheet contains the transformer reliability function and produces the retirement rates. The probabilities of retirement generated in this worksheet are used to calculate the annual retirements in the stock sheets.

10A.1.1.14 Life-Cycle Cost Data by Equipment Class

This worksheet contains energy loss (or consumption) and first-cost data for different equipment classes. As the name suggests, the data for this worksheet come directly from the life-cycle cost (LCC) analysis. The load growth calculations for liquid-immersed and dry-type transformers are also carried out in this worksheet.

10A.1.1.15 Life-Cycle Cost Input Data

Data in this worksheet are the mean values for the different variables from the Monte Carlo simulation runs of the LCC for individual design lines.

10A.1.1.16 Market Share Data

This worksheet contains the market shares of the different transformer design lines. The worksheet also calculates the 0.75 scaling factors for each design line.

10A.1.1.17 Site2Source

This worksheet contains the conversion factors for calculating source energy from site energy.

10A.1.1.18 Energy Information Administration Electricity Sales Data

This worksheet contains the historical and forecasted retail electricity sales data (obtained from DOE's Energy Information Administration (EIA)).

10A.1.1.19 Annual Energy Price Forecast

This worksheet contains the EIA's Annual Energy Outlook (AEO) 2010 forecast data for the electric power sector for the different economic growth scenarios (i.e., reference, high, and low). This forecast is used to estimate future growth in shipments.

10A.1.1.20 Rescaled Life-Cycle Cost Inputs

This worksheet applies the 0.75 scaling factors to convert the LCC input data for representative units into LCC input values representing all sizes within a design line.

10A.1.2 National Impact Analysis Spreadsheet Operating Instructions

Basic instructions for operating the NIA spreadsheet are as follows:

1. After downloading the NIA spreadsheet file from DOE's website, open the file using Excel. At the bottom, click on the tab for the worksheet "National Impact Summary." This worksheet serves as the user interface for running the model for a particular product class. To provide flexibility, the spreadsheet permits some user modifications to the model. The user may select a particular macroeconomic forecast which determines fuel prices, electricity sales, and income data to be used by the model. The user may also directly input new values for implicit discount rates, which quantify consumer preference for immediate, instead of delayed, savings. Additionally, the user can select long-term purchase elasticities for transformers.

2. Use 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 model parameters listed in the gray box labeled "Inputs." The parameters are:

   a) Economic Growth: To change the value, use the drop-down menu. Select the desired growth level (Reference, Low, or High).

   b) Discount Rate: To change the value, use the drop-down menu. Select the desired discount rate.

   c) Elasticity Liquid-Immersed Type: To change the value, use the drop-down menu to pick a level (Medium, High, Low).

   d) Elasticity Dry-Type: To change the value, use the drop-down menu to pick a level (Medium, High, Low).

4. The user can now select the desired equipment class from the drop-down menu and view the results in the summary table for that equipment class. To produce results for all equipment classes, the user will need to click the "All Classes Summary" button. When the user gets a message saying "Done," the calculations are complete. Results from this run will be available in the "Ship-NES-NPV Outputs" worksheet.

APPENDIX 10B. NATIONAL ENERGY SAVINGS AND NET NATIONAL PRESENT VALUE RESULTS

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10B.1 SUMMARY OF RESULTS

10B.1.1 Liquid-Immersed Summary

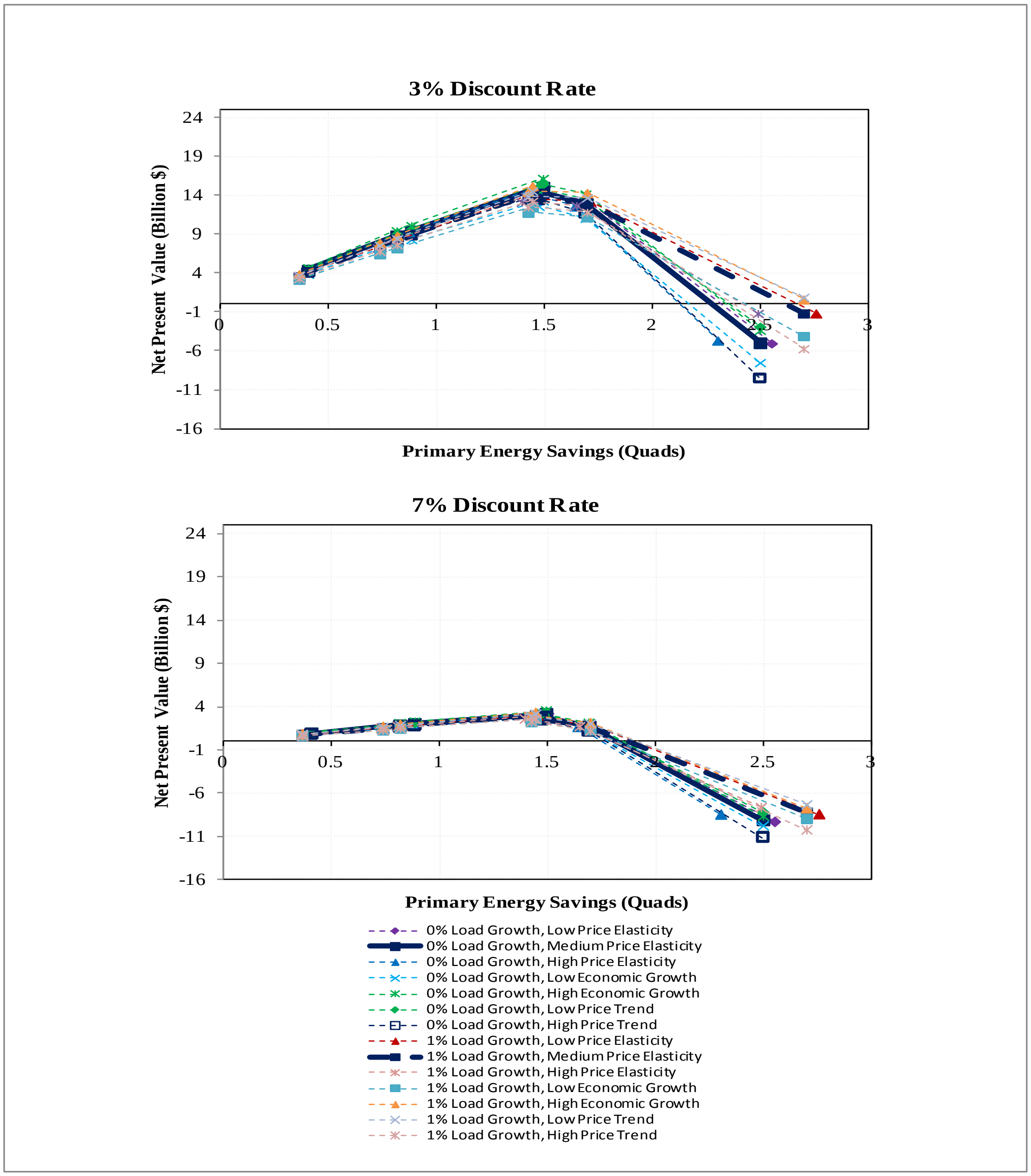

Figure 10B.1.1 Liquid-Immersed: Net Present Value (3% and 7% Discount Rate) versus Primary Energy Savings

10B.1.2 LVDT Summary

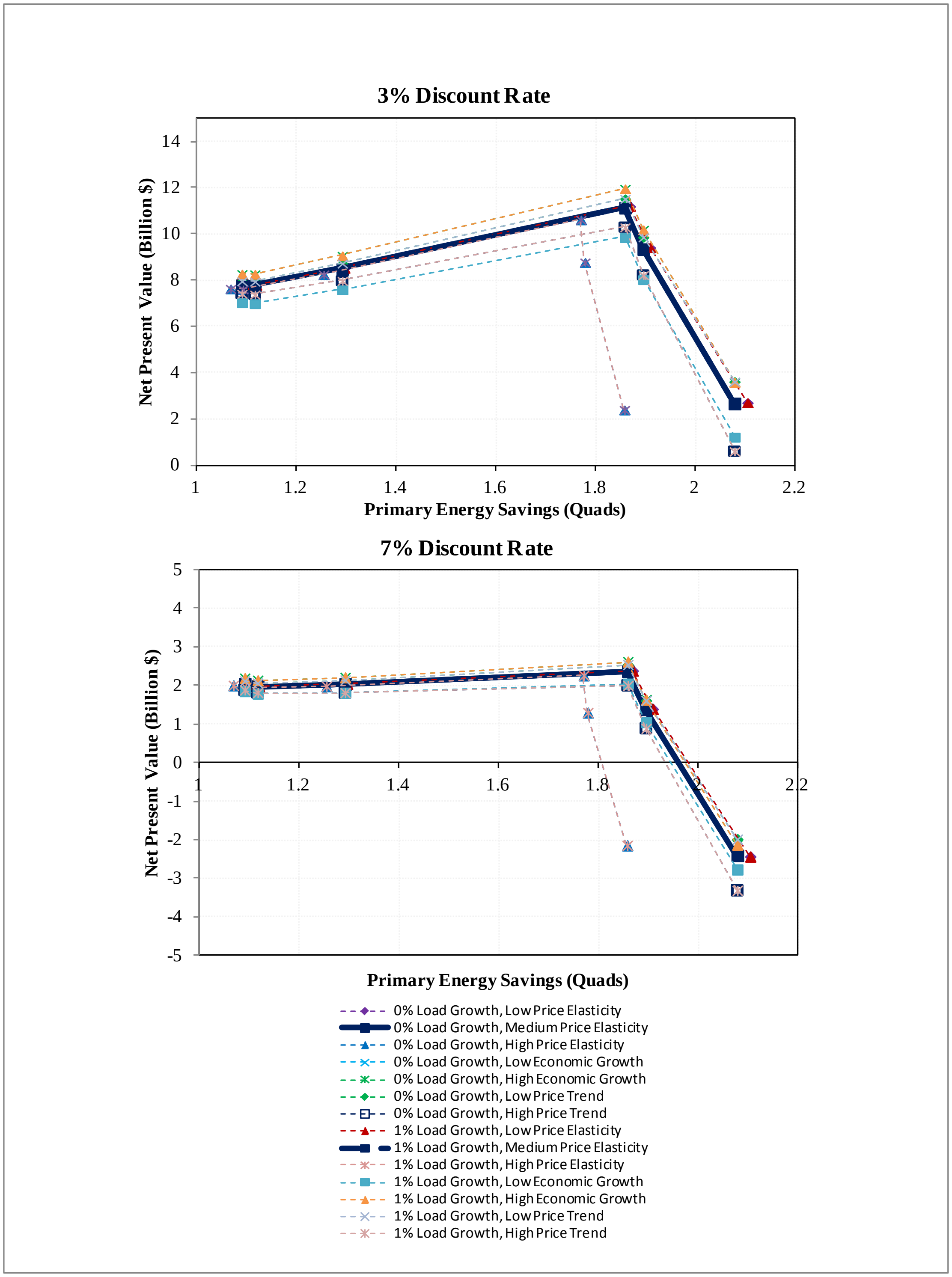

Figure 10B.1.2 LVDT: Net Present Value (3% and 7% Discount Rate) versus Primary Energy Savings

10B.1.3 MVDT Summary

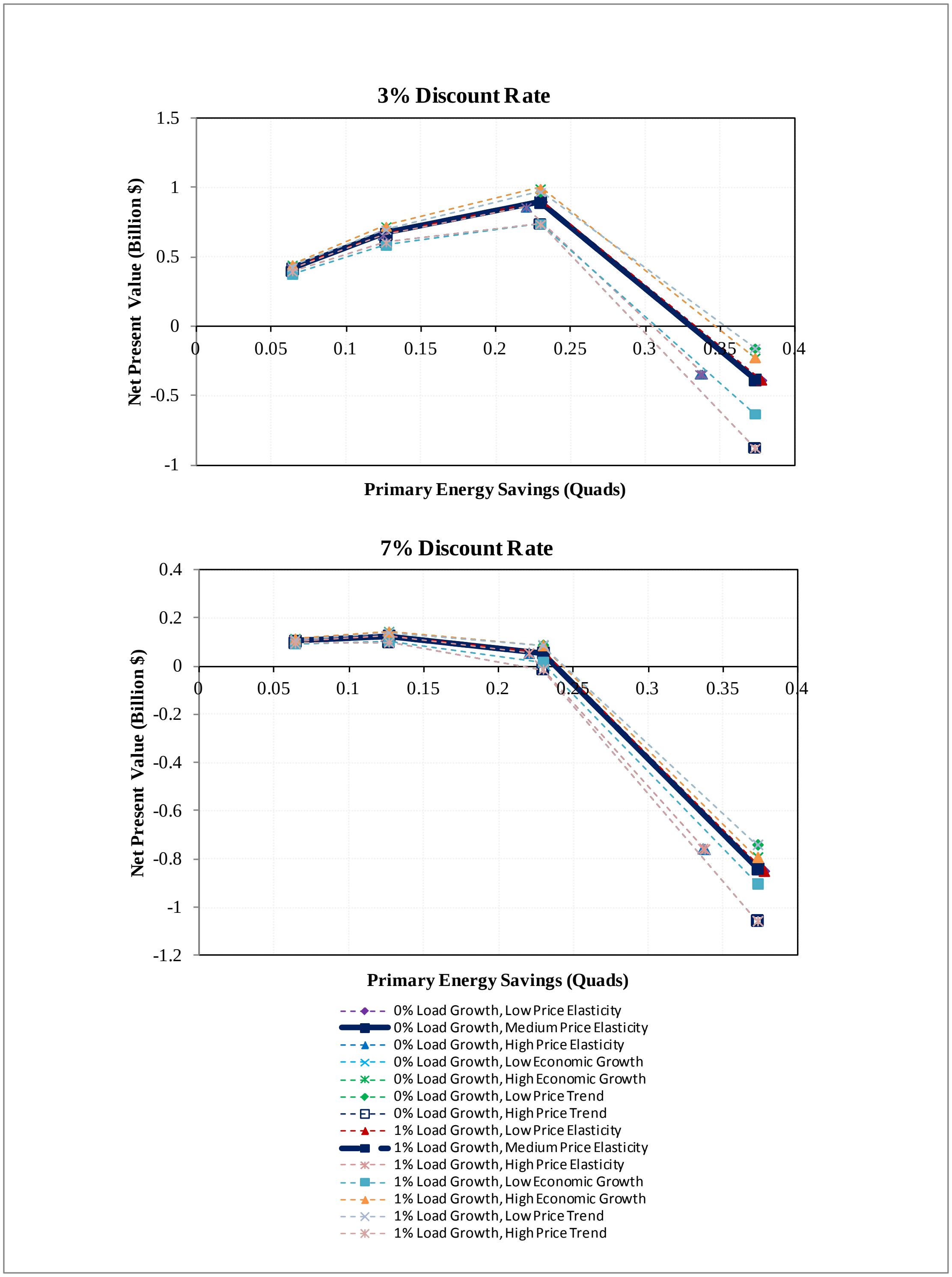

Figure 10B.1.3 MVDT: Net Present Value (3% and 7% Discount Rate) versus Primary Energy Savings

10B.2 0 PERCENT LOAD GROWTH, LIQUID-IMMERSED (0 PERCENT DRY-TYPE)

10B.2.4 Low Price Elasticity Scenario

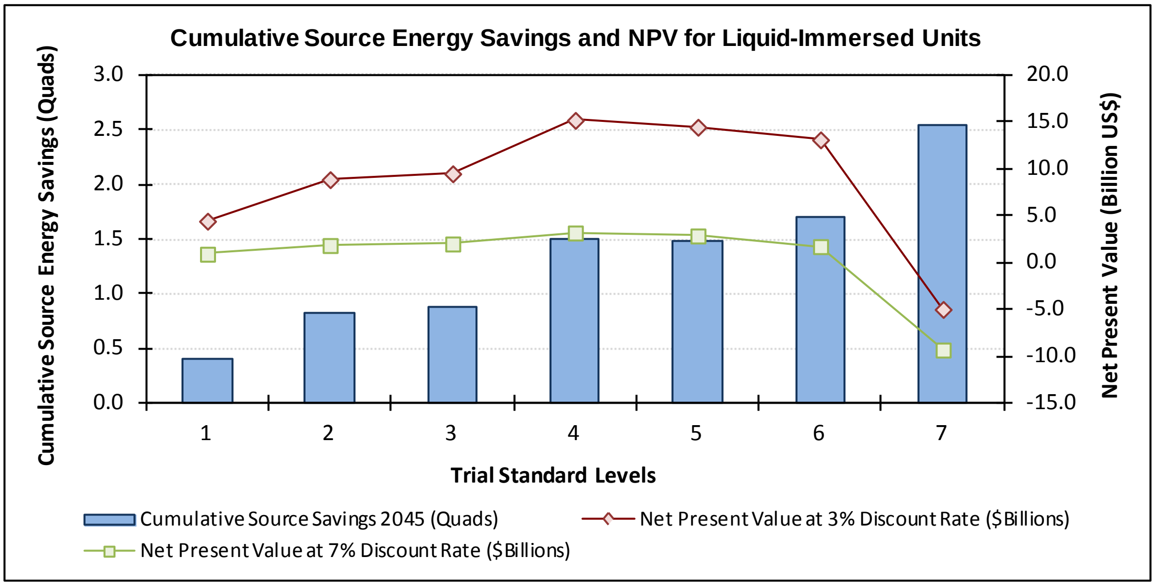

Figure 10B.2.1 Liquid-Immersed Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario

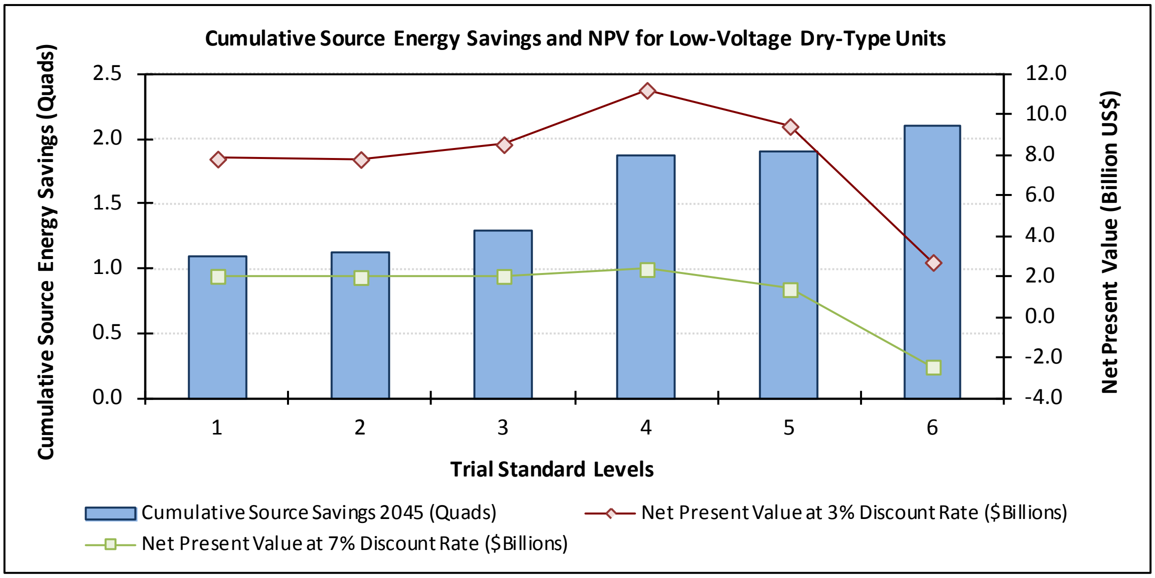

Figure 10B.2.2 LVDT Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario

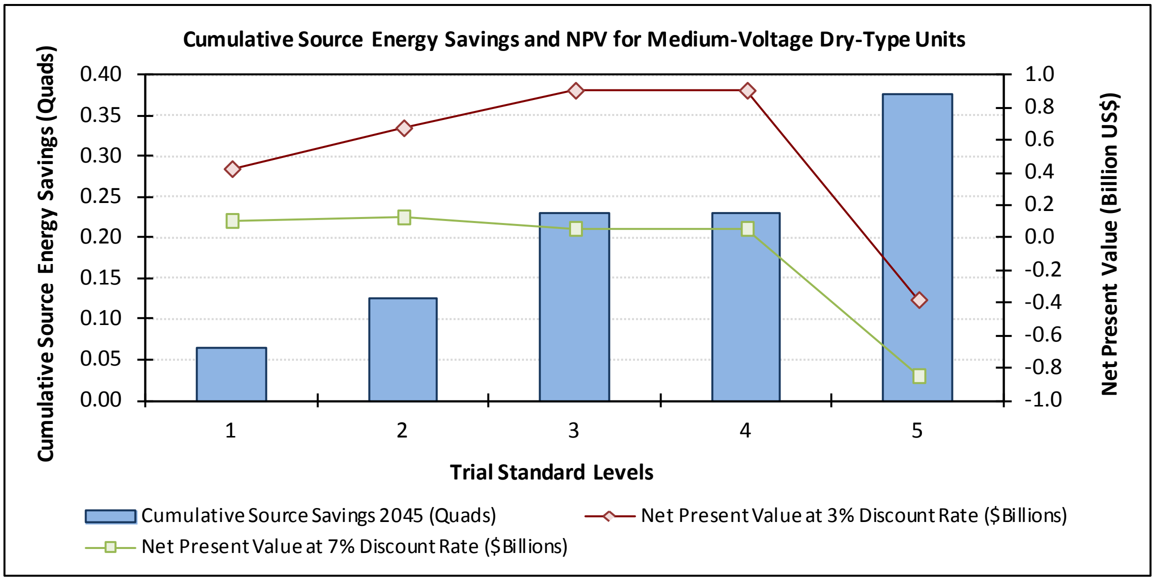

Figure 10B.2.3 MVDT Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario

10B.2.4.2 3 Percent Discount Rate

Table 10B.2.1 Liquid-Immersed Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
Equipment Cost ($Billions)	63.05	-2.46	-4.92	-5.11	-8.36	-8.80	-12.43	-39.64
Operating Cost (Savings in TSLs) ($Billions)	67.01	6.91	13.81	14.62	23.58	23.28	25.57	34.68
Cumulative Source Savings 2045 (Quads)		0.406	0.817	0.885	1.50	1.48	1.70	2.55
Net Present Value at 3% Discount Rate ($Billions)		4.45	8.89	9.52	15.22	14.49	13.14	-4.96
Net Present Value at 7% Discount Rate ($Billions)		0.933	1.86	2.02	3.20	2.88	1.74	-9.30

Table 10B.2.2 LVDT Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.617	0.617	0.617	0.617	0.617	0.617
Equipment Cost ($Billions)	19.51	-2.31	-2.58	-3.49	-6.12	-8.29	-16.94
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.14	10.39	12.03	17.34	17.73	19.67
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.30	1.87	1.91	2.10
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.81	8.54	11.22	9.44	2.72
Net Present Value at 7% Discount Rate ($Billions)		2.04	1.98	2.03	2.37	1.38	-2.44

Table 10B.2.3 MVDT Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.223	0.223	0.223
Equipment Cost ($Billions)	4.79	-0.155	-0.453	-1.19	-1.19	-3.73
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.09	2.09	3.35
Cumulative Source Savings 2045 (Quads)		0.064	0.127	0.231	0.231	0.377
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.674	0.905	0.905	-0.383
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.056	0.056	-0.850

Table 10B.2.4 Equipment Class 1, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.801	0.801	0.801	0.801	0.801	0.801	0.801
Equipment Cost ($Billions)	43.68	-1.03	-3.49	-3.50	-5.12	-5.95	-7.96	-24.08
Operating Cost (Savings in TSLs) ($Billions)	33.01	0.834	7.73	7.81	12.22	12.45	13.29	17.13
Cumulative Source Savings 2045 (Quads)		0.076	0.487	0.492	0.779	0.810	0.891	1.28
Net Present Value at 3% Discount Rate ($Billions)		-0.192	4.24	4.31	7.09	6.50	5.33	-6.95
Net Present Value at 7% Discount Rate ($Billions)		-0.261	0.664	0.684	1.25	0.900	0.140	-6.90

Table 10B.2.5 Equipment Class 2, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.24	-2.84	-4.47	-15.56
Operating Cost (Savings in TSLs) ($Billions)	34.00	6.08	6.08	6.81	11.36	10.83	12.28	17.55
Cumulative Source Savings 2045 (Quads)		0.330	0.330	0.393	0.720	0.670	0.810	1.27
Net Present Value at 3% Discount Rate ($Billions)		4.65	4.65	5.21	8.12	7.99	7.80	1.99
Net Present Value at 7% Discount Rate ($Billions)		1.19	1.19	1.34	1.94	1.98	1.60	-2.40

Table 10B.2.6 Equipment Class 3, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.022	0.022	0.022	0.022	0.022
Equipment Cost ($Billions)	0.900	0.0000	-0.269	-0.242	-0.424	-0.424	-0.936
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.247	0.421	0.574	0.574	0.644
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.062	0.062	0.069
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.179	0.149	0.149	-0.292
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.060	0.0096	-0.035	-0.035	-0.276

Table 10B.2.7 Equipment Class 4, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.596	0.596	0.596	0.596	0.596	0.596
Equipment Cost ($Billions)	18.61	-2.31	-2.31	-3.25	-5.70	-7.87	-16.01
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.14	10.14	11.61	16.77	17.16	19.02
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.81	1.85	2.04
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.83	8.36	11.07	9.29	3.02
Net Present Value at 7% Discount Rate ($Billions)		2.04	2.04	2.02	2.41	1.42	-2.17

Table 10B.2.8 Equipment Class 5, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0066
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.2.9 Equipment Class 6, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.481
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.412
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.081	0.084	0.084	-0.069
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.116

Table 10B.2.10 Equipment Class 7, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0030	0.0067	0.0067	0.010
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0025

Table 10B.2.11 Equipment Class 8, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.173	0.173	0.173
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.10	-1.10	-3.02
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.921	1.88	1.88	2.70
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.206	0.206	0.304
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.557	0.783	0.783	-0.318
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.690

Table 10B.2.12 Equipment Class 9, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0015
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.2.13 Equipment Class 10, 0 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.218
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0086	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0025	0.0024	-0.040

10B.2.4.1 7 Percent Discount Rate

Table 10B.2.14 Liquid-Immersed Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
Equipment Cost ($Billions)	32.28	-1.26	-2.52	-2.61	-4.28	-4.50	-6.37	-20.29
Operating Cost (Savings in TSLs) ($Billions)	21.25	2.19	4.38	4.64	7.48	7.38	8.11	11.00
Cumulative Source Savings 2045 (Quads)		0.406	0.817	0.885	1.50	1.48	1.70	2.55
Net Present Value at 3% Discount Rate ($Billions)		4.45	8.89	9.52	15.22	14.49	13.14	-4.96
Net Present Value at 7% Discount Rate ($Billions)		0.933	1.86	2.02	3.20	2.88	1.74	-9.30

Table 10B.2.15 LVDT Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.617	0.617	0.617	0.617	0.617	0.617
Equipment Cost ($Billions)	10.02	-1.19	-1.32	-1.79	-3.14	-4.26	-8.70
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.83	5.52	5.64	6.26
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.30	1.87	1.91	2.10
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.81	8.54	11.22	9.44	2.72
Net Present Value at 7% Discount Rate ($Billions)		2.04	1.98	2.03	2.37	1.38	-2.44

Table 10B.2.16 MVDT Transformers, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.223	0.223	0.223
Equipment Cost ($Billions)	2.46	-0.079	-0.233	-0.610	-0.610	-1.91
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.359	0.666	0.666	1.06
Cumulative Source Savings 2045 (Quads)		0.064	0.127	0.231	0.231	0.377
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.674	0.905	0.905	-0.383
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.056	0.056	-0.850

Table 10B.2.17 Equipment Class 1, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.801	0.801	0.801	0.801	0.801	0.801	0.801
Equipment Cost ($Billions)	22.36	-0.525	-1.79	-1.79	-2.62	-3.05	-4.07	-12.33
Operating Cost (Savings in TSLs) ($Billions)	10.47	0.264	2.45	2.48	3.87	3.95	4.21	5.43
Cumulative Source Savings 2045 (Quads)		0.076	0.487	0.492	0.779	0.810	0.891	1.28
Net Present Value at 3% Discount Rate ($Billions)		-0.192	4.24	4.31	7.09	6.50	5.33	-6.95
Net Present Value at 7% Discount Rate ($Billions)		-0.261	0.664	0.684	1.25	0.900	0.140	-6.90

Table 10B.2.18 Equipment Class 2, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Equipment Cost ($Billions)	9.92	-0.734	-0.734	-0.821	-1.66	-1.46	-2.29	-7.97
Operating Cost (Savings in TSLs) ($Billions)	10.78	1.93	1.93	2.16	3.60	3.44	3.89	5.56
Cumulative Source Savings 2045 (Quads)		0.330	0.330	0.393	0.720	0.670	0.810	1.27
Net Present Value at 3% Discount Rate ($Billions)		4.65	4.65	5.21	8.12	7.99	7.80	1.99
Net Present Value at 7% Discount Rate ($Billions)		1.19	1.19	1.34	1.94	1.98	1.60	-2.40

Table 10B.2.19 Equipment Class 3, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.022	0.022	0.022	0.022	0.022
Equipment Cost ($Billions)	0.462	0.0000	-0.138	-0.124	-0.218	-0.218	-0.481
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.079	0.134	0.183	0.183	0.205
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.062	0.062	0.069
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.179	0.149	0.149	-0.292
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.060	0.0096	-0.035	-0.035	-0.276

Table 10B.2.20 Equipment Class 4, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.596	0.596	0.596	0.596	0.596	0.596
Equipment Cost ($Billions)	9.56	-1.19	-1.19	-1.67	-2.92	-4.04	-8.22
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.69	5.33	5.46	6.05
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.81	1.85	2.04
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.83	8.36	11.07	9.29	3.02
Net Present Value at 7% Discount Rate ($Billions)		2.04	2.04	2.02	2.41	1.42	-2.17

Table 10B.2.21 Equipment Class 5, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0034
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.2.22 Equipment Class 6, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.247
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.131
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.081	0.084	0.084	-0.069
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.116

Table 10B.2.23 Equipment Class 7, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0021	-0.0021	-0.0057
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0025

Table 10B.2.24 Equipment Class 8, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.173	0.173	0.173
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.562	-0.562	-1.55
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.598	0.598	0.858
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.206	0.206	0.304
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.557	0.783	0.783	-0.318
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.690

Table 10B.2.25 Equipment Class 9, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0008
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.2.26 Equipment Class 10, 0 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0086	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0025	0.0024	-0.040

10B.2.5 Medium Price Elasticity Scenario

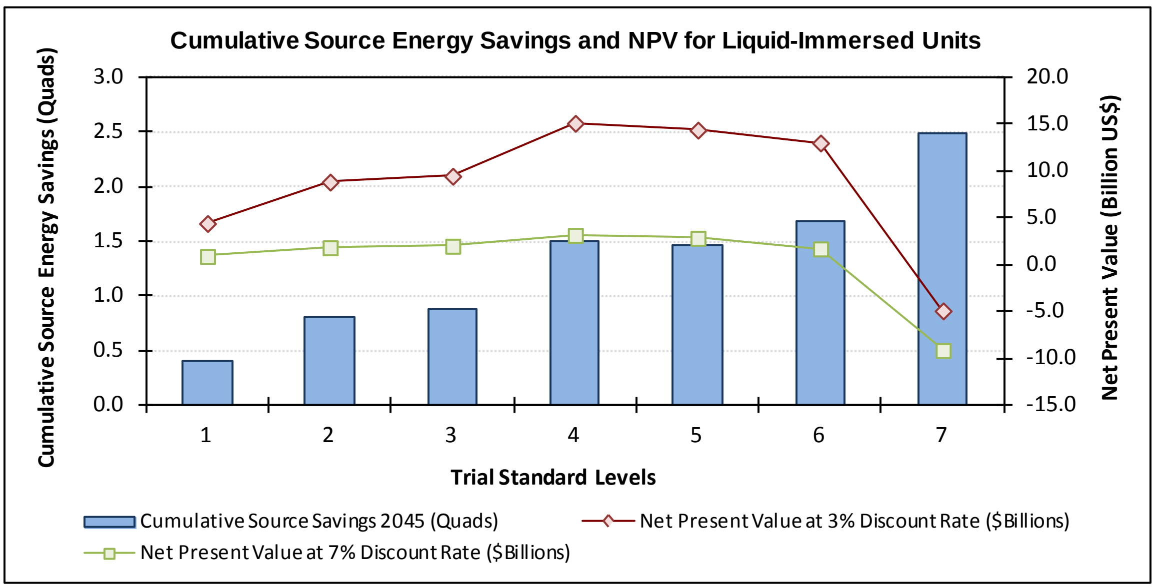

Figure 10B.2.4 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario

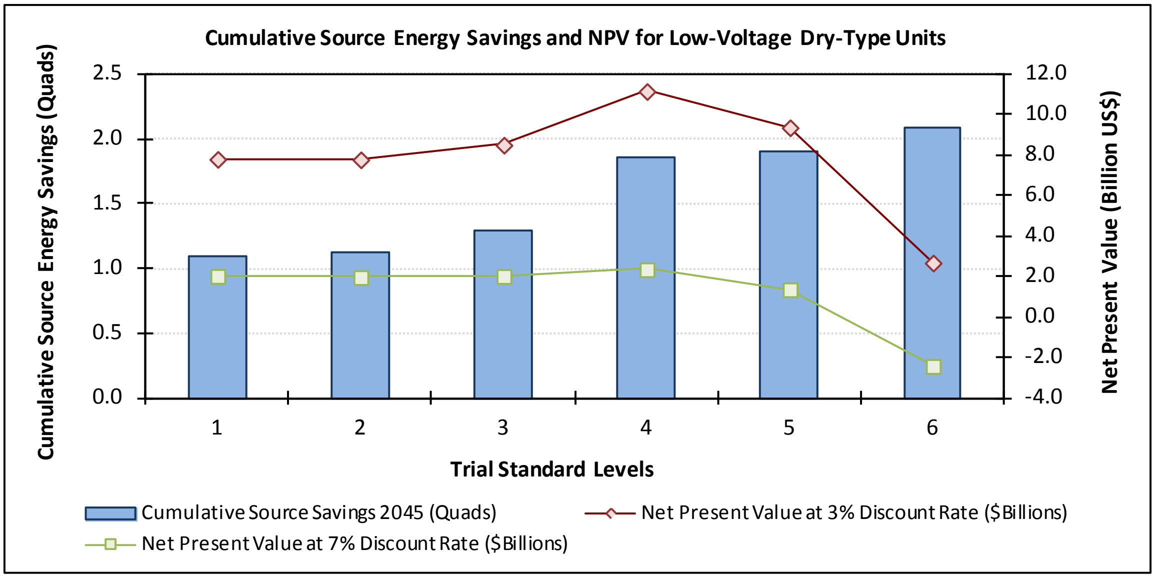

Figure 10B.2.5 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario

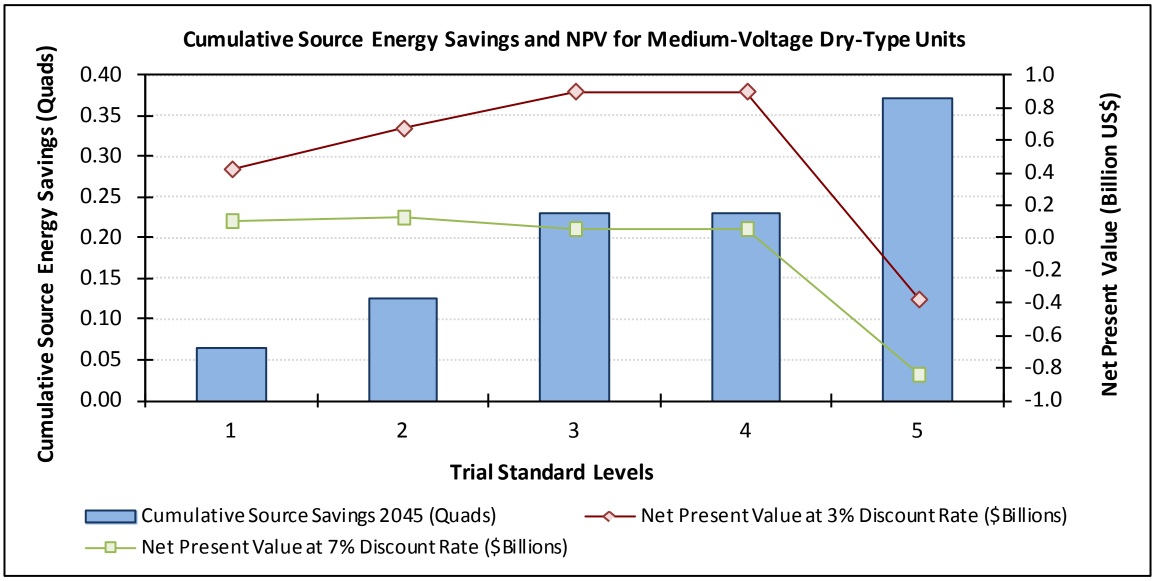

Figure 10B.2.6 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario

10B.2.5.2 3 Percent Discount Rate

Table 10B.2.27 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	63.05	-2.45	-4.91	-5.09	-8.32	-8.75	-12.34	-38.84
Operating Cost (Savings in TSLs) ($Billions)	67.01	6.90	13.77	14.58	23.45	23.16	25.37	33.95
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.44	8.86	9.49	15.13	14.41	13.03	-4.89
Net Present Value at 7% Discount Rate ($Billions)		0.930	1.85	2.02	3.18	2.86	1.73	-9.12

Table 10B.2.28 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	19.51	-2.30	-2.57	-3.48	-6.09	-8.23	-16.73
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.11	10.36	11.99	17.25	17.61	19.42
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.79	8.51	11.16	9.37	2.69
Net Present Value at 7% Discount Rate ($Billions)		2.03	1.97	2.03	2.36	1.37	-2.41

Table 10B.2.29 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.79	-0.154	-0.452	-1.18	-1.18	-3.69
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.08	2.08	3.31
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.673	0.901	0.901	-0.378
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.055	0.055	-0.841

Table 10B.2.30 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	43.68	-1.02	-3.48	-3.49	-5.10	-5.92	-7.90	-23.65
Operating Cost (Savings in TSLs) ($Billions)	33.01	0.833	7.71	7.79	12.16	12.39	13.20	16.82
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.192	4.23	4.30	7.06	6.46	5.30	-6.83
Net Present Value at 7% Discount Rate ($Billions)		-0.261	0.662	0.682	1.25	0.896	0.139	-6.77

Table 10B.2.31 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.22	-2.83	-4.44	-15.19
Operating Cost (Savings in TSLs) ($Billions)	34.00	6.06	6.06	6.79	11.29	10.77	12.17	17.13
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.63	4.63	5.19	8.07	7.94	7.74	1.94
Net Present Value at 7% Discount Rate ($Billions)		1.19	1.19	1.33	1.93	1.97	1.59	-2.34

Table 10B.2.32 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.900	0.0000	-0.268	-0.241	-0.421	-0.421	-0.923
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.246	0.419	0.569	0.569	0.635
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.178	0.148	0.148	-0.288
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.059	0.0095	-0.035	-0.035	-0.272

Table 10B.2.33 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	18.61	-2.30	-2.30	-3.24	-5.67	-7.81	-15.81
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.11	10.11	11.57	16.68	17.04	18.79
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.81	8.33	11.01	9.22	2.98
Net Present Value at 7% Discount Rate ($Billions)		2.03	2.03	2.02	2.40	1.41	-2.14

Table 10B.2.34 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0065
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.2.35 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.475
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.407
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.080	0.084	0.084	-0.068
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.115

Table 10B.2.36 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0067	0.0067	0.0099
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0024

Table 10B.2.37 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.09	-1.09	-2.98
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.920	1.87	1.87	2.67
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.556	0.779	0.779	-0.314
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.682

Table 10B.2.38 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.2.39 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.217
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0024	0.0024	-0.040

10B.2.5.3 7 Percent Discount Rate

Table 10B.2.40 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
Operating Cost (Savings in TSLs) ($Billions)	21.25	2.19	4.37	4.62	7.44	7.34	8.05	10.77
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.44	8.86	9.49	15.13	14.41	13.03	-4.89
Net Present Value at 7% Discount Rate ($Billions)		0.930	1.85	2.02	3.18	2.86	1.73	-9.12

Table 10B.2.41 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.81	5.49	5.60	6.18
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.79	8.51	11.16	9.37	2.69
Net Present Value at 7% Discount Rate ($Billions)		2.03	1.97	2.03	2.36	1.37	-2.41

Table 10B.2.42 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.358	0.663	0.663	1.05
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.673	0.901	0.901	-0.378
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.055	0.055	-0.841

Table 10B.2.43 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	22.36	-0.525	-1.78	-1.79	-2.61	-3.03	-4.05	-12.11
Operating Cost (Savings in TSLs) ($Billions)	10.47	0.264	2.44	2.47	3.86	3.93	4.19	5.33
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.192	4.23	4.30	7.06	6.46	5.30	-6.83
Net Present Value at 7% Discount Rate ($Billions)		-0.261	0.662	0.682	1.25	0.896	0.139	-6.77

Table 10B.2.44 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.92	-0.732	-0.732	-0.818	-1.65	-1.45	-2.27	-7.78
Operating Cost (Savings in TSLs) ($Billions)	10.78	1.92	1.92	2.15	3.58	3.42	3.86	5.43
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.63	4.63	5.19	8.07	7.94	7.74	1.94
Net Present Value at 7% Discount Rate ($Billions)		1.19	1.19	1.33	1.93	1.97	1.59	-2.34

Table 10B.2.45 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.462	0.0000	-0.137	-0.124	-0.216	-0.216	-0.474
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.078	0.133	0.181	0.181	0.202
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.178	0.148	0.148	-0.288
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.059	0.0095	-0.035	-0.035	-0.272

Table 10B.2.46 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.56	-1.18	-1.18	-1.66	-2.91	-4.01	-8.12
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.68	5.31	5.42	5.98
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.81	8.33	11.01	9.22	2.98
Net Present Value at 7% Discount Rate ($Billions)		2.03	2.03	2.02	2.40	1.41	-2.14

Table 10B.2.47 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0033
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.2.48 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.244
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.129
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.080	0.084	0.084	-0.068
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.115

Table 10B.2.49 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0056
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0024

Table 10B.2.50 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.560	-0.560	-1.53
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.595	0.595	0.848
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.556	0.779	0.779	-0.314
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.682

Table 10B.2.51 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.2.52 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0024	0.0024	-0.040

10B.2.6 High Price Elasticity Scenario

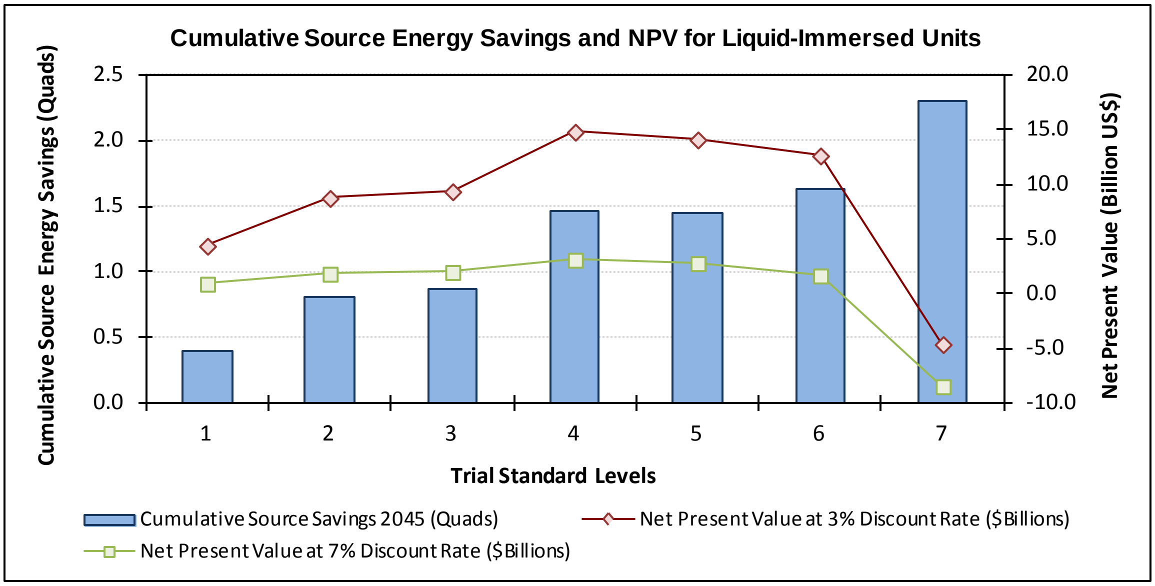

Figure 10B.2.7 Liquid-Immersed Transformers, 0 Percent Load Growth, High Price Elasticity Scenario

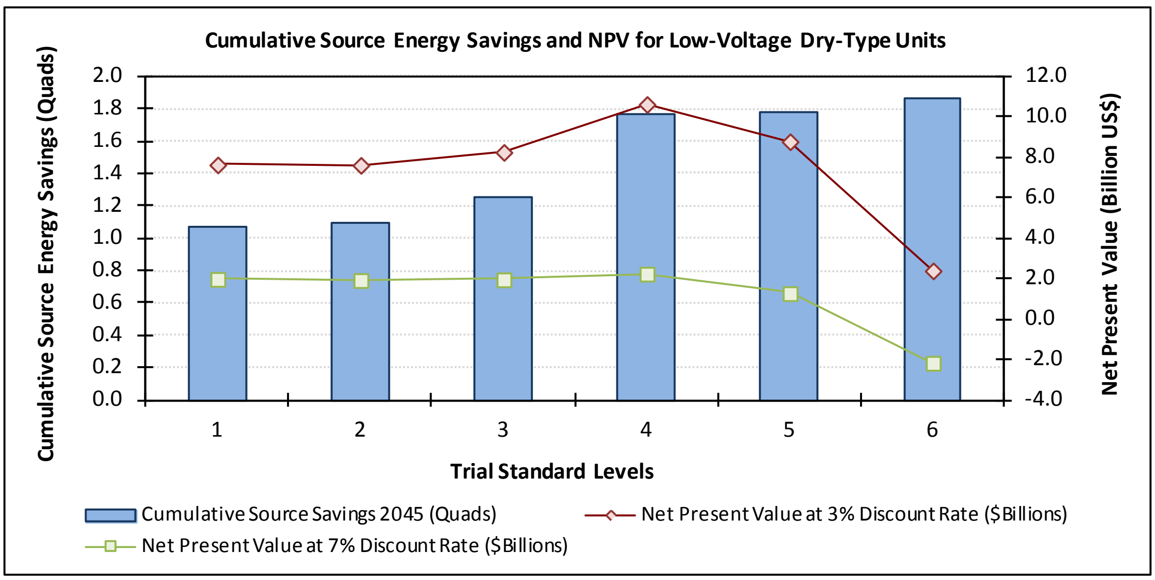

Figure 10B.2.8 LVDT Transformers, 0 Percent Load Growth, High Price Elasticity Scenario

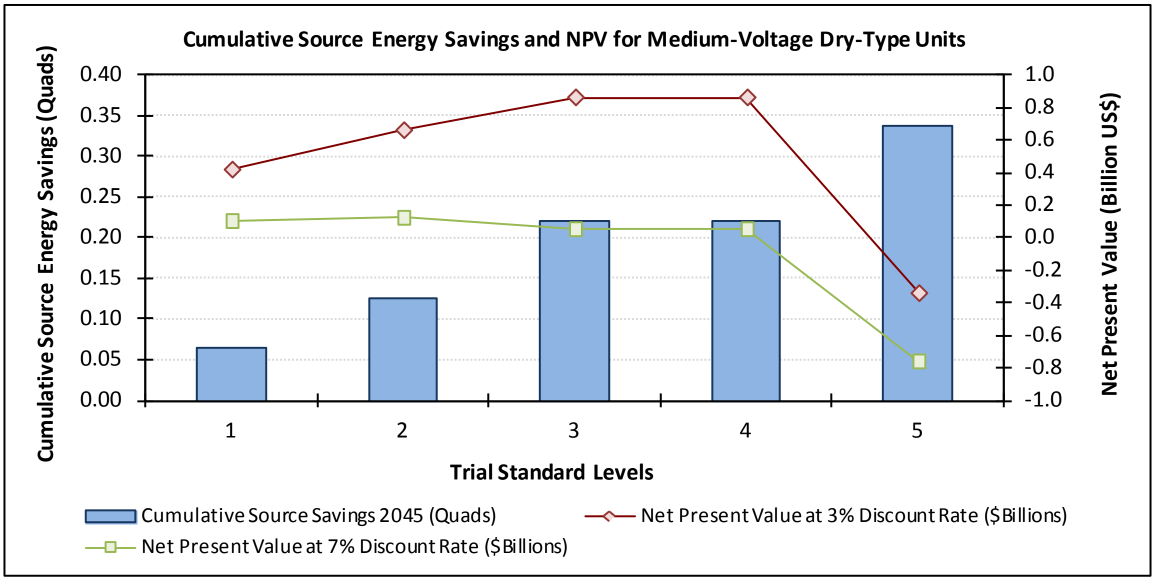

Figure 10B.2.9 MVDT Transformers, 0 Percent Load Growth, High Price Elasticity Scenario

10B.2.6.2 3 Percent Discount Rate

Table 10B.2.53 Liquid-Immersed Transformers, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.93	1.93	1.92	1.90	1.90	1.88	1.76
Equipment Cost ($Billions)	63.05	-2.43	-4.85	-5.03	-8.15	-8.57	-11.99	-35.88
Operating Cost (Savings in TSLs) ($Billions)	67.01	6.82	13.61	14.40	22.97	22.68	24.63	31.28
Cumulative Source Savings 2045 (Quads)		0.401	0.805	0.872	1.46	1.44	1.64	2.30
Net Present Value at 3% Discount Rate ($Billions)		4.39	8.76	9.37	14.81	14.11	12.64	-4.60
Net Present Value at 7% Discount Rate ($Billions)		0.918	1.83	1.99	3.11	2.80	1.67	-8.45

Table 10B.2.54 LVDT Transformers, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.603	0.602	0.597	0.585	0.575	0.545
Equipment Cost ($Billions)	19.51	-2.26	-2.51	-3.37	-5.79	-7.73	-14.95
Operating Cost (Savings in TSLs) ($Billions)	26.54	9.90	10.14	11.64	16.43	16.52	17.36
Cumulative Source Savings 2045 (Quads)		1.07	1.09	1.25	1.77	1.78	1.86
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.63	8.27	10.63	8.79	2.41
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.93	1.97	2.25	1.29	-2.15

Table 10B.2.55 MVDT Transformers, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.222	0.220	0.214	0.214	0.200
Equipment Cost ($Billions)	4.79	-0.153	-0.445	-1.13	-1.13	-3.34
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.574	1.11	2.00	2.00	3.00
Cumulative Source Savings 2045 (Quads)		0.063	0.124	0.220	0.220	0.338
Net Present Value at 3% Discount Rate ($Billions)		0.420	0.662	0.864	0.864	-0.340
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.124	0.054	0.053	-0.760

Table 10B.2.56 Equipment Class 1, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.797	0.788	0.788	0.783	0.780	0.774	0.733
Equipment Cost ($Billions)	43.68	-1.02	-3.44	-3.45	-5.01	-5.80	-7.70	-22.05
Operating Cost (Savings in TSLs) ($Billions)	33.01	0.830	7.61	7.69	11.95	12.14	12.85	15.69
Cumulative Source Savings 2045 (Quads)		0.076	0.480	0.484	0.762	0.790	0.862	1.17
Net Present Value at 3% Discount Rate ($Billions)		-0.191	4.17	4.24	6.94	6.33	5.16	-6.37
Net Present Value at 7% Discount Rate ($Billions)		-0.260	0.654	0.674	1.22	0.878	0.136	-6.32

Table 10B.2.57 Equipment Class 2, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.14	1.14	1.14	1.12	1.12	1.11	1.03
Equipment Cost ($Billions)	19.37	-1.41	-1.41	-1.58	-3.14	-2.77	-4.29	-13.83
Operating Cost (Savings in TSLs) ($Billions)	34.00	5.99	5.99	6.70	11.02	10.54	11.78	15.60
Cumulative Source Savings 2045 (Quads)		0.325	0.325	0.387	0.698	0.652	0.777	1.13
Net Present Value at 3% Discount Rate ($Billions)		4.58	4.58	5.12	7.88	7.77	7.49	1.77
Net Present Value at 7% Discount Rate ($Billions)		1.18	1.18	1.32	1.89	1.93	1.54	-2.13

Table 10B.2.58 Equipment Class 3, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.020	0.021	0.020	0.020	0.019
Equipment Cost ($Billions)	0.900	0.0000	-0.255	-0.231	-0.393	-0.393	-0.812
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.235	0.401	0.531	0.531	0.558
Cumulative Source Savings 2045 (Quads)		0.0000	0.025	0.044	0.057	0.057	0.060
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.021	0.170	0.138	0.138	-0.253
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.0091	-0.033	-0.033	-0.239

Table 10B.2.59 Equipment Class 4, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.582	0.582	0.577	0.565	0.555	0.526
Equipment Cost ($Billions)	18.61	-2.26	-2.26	-3.14	-5.40	-7.33	-14.14
Operating Cost (Savings in TSLs) ($Billions)	25.68	9.90	9.90	11.24	15.90	15.99	16.80
Cumulative Source Savings 2045 (Quads)		1.07	1.07	1.21	1.71	1.72	1.80
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.65	8.10	10.50	8.66	2.66
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.99	1.96	2.28	1.32	-1.92

Table 10B.2.60 Equipment Class 5, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0059
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0056
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0006
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0013

Table 10B.2.61 Equipment Class 6, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.032	0.032	0.032	0.029
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.428
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.123	0.128	0.128	0.366
Cumulative Source Savings 2045 (Quads)		0.0071	0.014	0.015	0.015	0.042
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.079	0.082	0.082	-0.061
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.017	0.017	-0.103

Table 10B.2.62 Equipment Class 7, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0038	-0.0038	-0.0099
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0064	0.0064	0.0090
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0010
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0026	0.0026	-0.0009
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0022

Table 10B.2.63 Equipment Class 8, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.172	0.170	0.165	0.165	0.154
Equipment Cost ($Billions)	3.80	-0.143	-0.358	-1.04	-1.04	-2.68
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.482	0.905	1.79	1.79	2.40
Cumulative Source Savings 2045 (Quads)		0.053	0.101	0.196	0.196	0.271
Net Present Value at 3% Discount Rate ($Billions)		0.339	0.547	0.745	0.745	-0.283
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.104	0.033	0.033	-0.614

Table 10B.2.64 Equipment Class 9, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0013
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0014
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.2.65 Equipment Class 10, 0 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.041	-0.207
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.075	0.075	0.074	0.212
Cumulative Source Savings 2045 (Quads)		0.0029	0.0084	0.0084	0.0084	0.023
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.033	0.033	0.033	0.0054
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0024	0.0024	0.0024	-0.039

10B.2.6.3 7 Percent Discount Rate

Table 10B.2.66 Liquid-Immersed Transformers, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.93	1.93	1.92	1.90	1.90	1.88	1.76
Equipment Cost ($Billions)	32.28	-1.25	-2.48	-2.57	-4.17	-4.39	-6.14	-18.37
Operating Cost (Savings in TSLs) ($Billions)	21.25	2.16	4.32	4.57	7.28	7.19	7.81	9.92
Cumulative Source Savings 2045 (Quads)		0.401	0.805	0.872	1.46	1.44	1.64	2.30
Net Present Value at 3% Discount Rate ($Billions)		4.39	8.76	9.37	14.81	14.11	12.64	-4.60
Net Present Value at 7% Discount Rate ($Billions)		0.918	1.83	1.99	3.11	2.80	1.67	-8.45

Table 10B.2.67 LVDT Transformers, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.603	0.602	0.597	0.585	0.575	0.545
Equipment Cost ($Billions)	10.02	-1.16	-1.29	-1.73	-2.97	-3.97	-7.68
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.15	3.22	3.70	5.23	5.25	5.52
Cumulative Source Savings 2045 (Quads)		1.07	1.09	1.25	1.77	1.78	1.86
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.63	8.27	10.63	8.79	2.41
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.93	1.97	2.25	1.29	-2.15

Table 10B.2.68 MVDT Transformers, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.222	0.220	0.214	0.214	0.200
Equipment Cost ($Billions)	2.46	-0.079	-0.229	-0.582	-0.582	-1.71
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.182	0.352	0.635	0.635	0.953
Cumulative Source Savings 2045 (Quads)		0.063	0.124	0.220	0.220	0.338
Net Present Value at 3% Discount Rate ($Billions)		0.420	0.662	0.864	0.864	-0.340
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.124	0.054	0.053	-0.760

Table 10B.2.69 Equipment Class 1, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.797	0.788	0.788	0.783	0.780	0.774	0.733
Equipment Cost ($Billions)	22.36	-0.523	-1.76	-1.77	-2.57	-2.97	-3.94	-11.29
Operating Cost (Savings in TSLs) ($Billions)	10.47	0.263	2.41	2.44	3.79	3.85	4.08	4.98
Cumulative Source Savings 2045 (Quads)		0.076	0.480	0.484	0.762	0.790	0.862	1.17
Net Present Value at 3% Discount Rate ($Billions)		-0.191	4.17	4.24	6.94	6.33	5.16	-6.37
Net Present Value at 7% Discount Rate ($Billions)		-0.260	0.654	0.674	1.22	0.878	0.136	-6.32

Table 10B.2.70 Equipment Class 2, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.14	1.14	1.14	1.12	1.12	1.11	1.03
Equipment Cost ($Billions)	9.92	-0.723	-0.723	-0.808	-1.61	-1.42	-2.20	-7.08
Operating Cost (Savings in TSLs) ($Billions)	10.78	1.90	1.90	2.13	3.49	3.34	3.74	4.95
Cumulative Source Savings 2045 (Quads)		0.325	0.325	0.387	0.698	0.652	0.777	1.13
Net Present Value at 3% Discount Rate ($Billions)		4.58	4.58	5.12	7.88	7.77	7.49	1.77
Net Present Value at 7% Discount Rate ($Billions)		1.18	1.18	1.32	1.89	1.93	1.54	-2.13

Table 10B.2.71 Equipment Class 3, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.020	0.021	0.020	0.020	0.019
Equipment Cost ($Billions)	0.462	0.0000	-0.131	-0.118	-0.202	-0.202	-0.417
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.075	0.128	0.169	0.169	0.178
Cumulative Source Savings 2045 (Quads)		0.0000	0.025	0.044	0.057	0.057	0.060
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.021	0.170	0.138	0.138	-0.253
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.0091	-0.033	-0.033	-0.239

Table 10B.2.72 Equipment Class 4, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.582	0.582	0.577	0.565	0.555	0.526
Equipment Cost ($Billions)	9.56	-1.16	-1.16	-1.61	-2.77	-3.77	-7.26
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.15	3.15	3.58	5.06	5.09	5.34
Cumulative Source Savings 2045 (Quads)		1.07	1.07	1.21	1.71	1.72	1.80
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.65	8.10	10.50	8.66	2.66
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.99	1.96	2.28	1.32	-1.92

Table 10B.2.73 Equipment Class 5, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003
Equipment Cost ($Billions)	0.0047	0.0000	-0.0002	-0.0003	-0.0003	-0.0030
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0018
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0006
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0013

Table 10B.2.74 Equipment Class 6, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.032	0.032	0.032	0.029
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.023	-0.023	-0.220
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.039	0.041	0.041	0.116
Cumulative Source Savings 2045 (Quads)		0.0071	0.014	0.015	0.015	0.042
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.079	0.082	0.082	-0.061
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.017	0.017	-0.103

Table 10B.2.75 Equipment Class 7, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0051
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0020	0.0020	0.0029
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0010
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0026	0.0026	-0.0009
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0022

Table 10B.2.76 Equipment Class 8, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.172	0.170	0.165	0.165	0.154
Equipment Cost ($Billions)	1.95	-0.073	-0.184	-0.535	-0.535	-1.38
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.153	0.288	0.568	0.568	0.764
Cumulative Source Savings 2045 (Quads)		0.053	0.101	0.196	0.196	0.271
Net Present Value at 3% Discount Rate ($Billions)		0.339	0.547	0.745	0.745	-0.283
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.104	0.033	0.033	-0.614

Table 10B.2.77 Equipment Class 9, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0004
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.2.78 Equipment Class 10, 0 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.021	-0.021	-0.021	-0.106
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0077	0.024	0.024	0.024	0.068
Cumulative Source Savings 2045 (Quads)		0.0029	0.0084	0.0084	0.0084	0.023
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.033	0.033	0.033	0.0054
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0024	0.0024	0.0024	-0.039

10B.2.7 Low Economic Growth Scenario

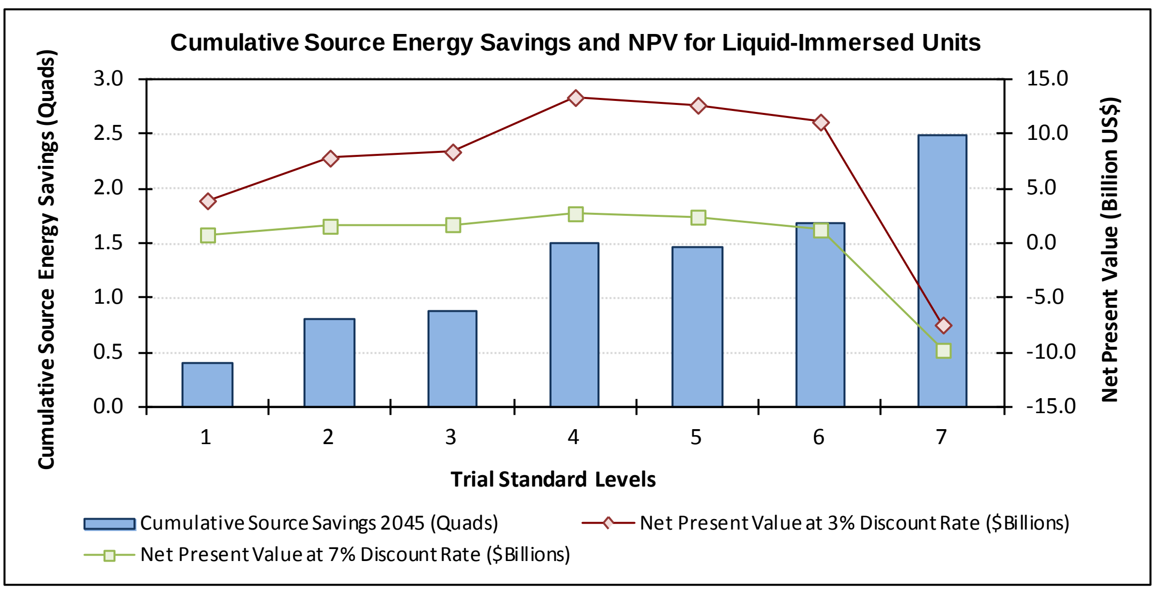

Figure 10B.2.10 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario

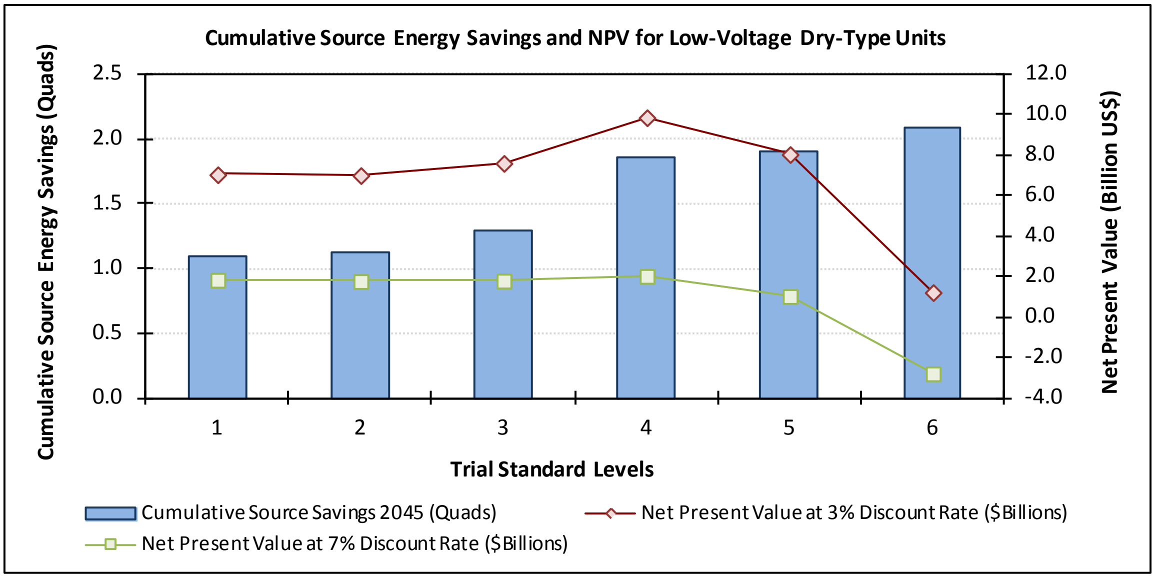

Figure 10B.2.11 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario

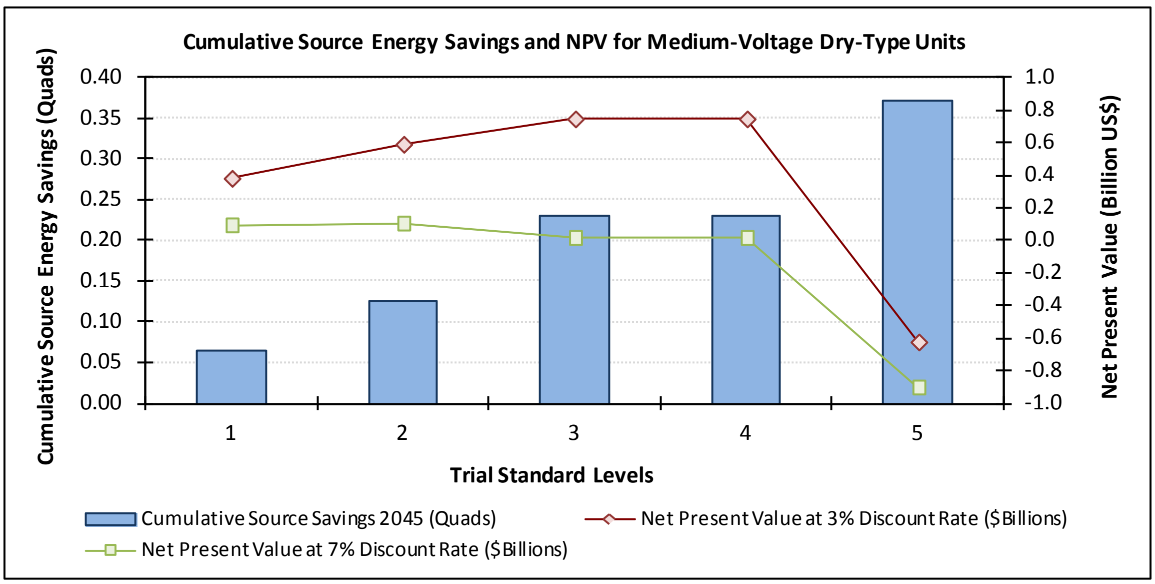

Figure 10B.2.12 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario

10B.2.7.2 3 Percent Discount Rate

Table 10B.2.79 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	63.05	-2.45	-4.91	-5.09	-8.32	-8.75	-12.34	-38.84
Operating Cost (Savings in TSLs) ($Billions)	61.97	6.38	12.73	13.48	21.69	21.42	23.46	31.40
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		3.92	7.82	8.39	13.37	12.66	11.12	-7.44
Net Present Value at 7% Discount Rate ($Billions)		0.800	1.59	1.74	2.74	2.43	1.25	-9.76

Table 10B.2.80 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	19.51	-2.30	-2.57	-3.48	-6.09	-8.23	-16.73
Operating Cost (Savings in TSLs) ($Billions)	24.55	9.36	9.58	11.09	15.95	16.28	17.96
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.01	7.61	9.87	8.05	1.23
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.78	1.80	2.04	1.04	-2.78

Table 10B.2.81 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.79	-0.154	-0.452	-1.18	-1.18	-3.69
Operating Cost (Savings in TSLs) ($Billions)	5.15	0.534	1.04	1.93	1.93	3.06
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.379	0.589	0.744	0.744	-0.626
Net Present Value at 7% Discount Rate ($Billions)		0.093	0.104	0.016	0.016	-0.903

Table 10B.2.82 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	43.68	-1.02	-3.48	-3.49	-5.10	-5.92	-7.90	-23.65
Operating Cost (Savings in TSLs) ($Billions)	30.52	0.770	7.13	7.20	11.25	11.45	12.21	15.56
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.255	3.65	3.71	6.15	5.53	4.30	-8.09
Net Present Value at 7% Discount Rate ($Billions)		-0.276	0.517	0.536	1.02	0.662	-0.109	-7.09

Table 10B.2.83 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.22	-2.83	-4.44	-15.19
Operating Cost (Savings in TSLs) ($Billions)	31.44	5.61	5.61	6.28	10.44	9.96	11.26	15.84
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.18	4.18	4.68	7.22	7.13	6.82	0.650
Net Present Value at 7% Discount Rate ($Billions)		1.08	1.08	1.21	1.72	1.76	1.36	-2.67

Table 10B.2.84 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.900	0.0000	-0.268	-0.241	-0.421	-0.421	-0.923
Operating Cost (Savings in TSLs) ($Billions)	0.791	0.0000	0.227	0.387	0.527	0.527	0.587
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.040	0.146	0.106	0.106	-0.336
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.064	0.0016	-0.046	-0.046	-0.284

Table 10B.2.85 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	18.61	-2.30	-2.30	-3.24	-5.67	-7.81	-15.81
Operating Cost (Savings in TSLs) ($Billions)	23.76	9.36	9.36	10.70	15.43	15.76	17.38
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.05	7.47	9.76	7.94	1.57
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.84	1.80	2.08	1.09	-2.50

Table 10B.2.86 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0065
Operating Cost (Savings in TSLs) ($Billions)	0.0099	0.0008	0.0014	0.0017	0.0017	0.0057
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0007	0.0009	0.0011	0.0011	-0.0008
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0015

Table 10B.2.87 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.475
Operating Cost (Savings in TSLs) ($Billions)	0.679	0.060	0.115	0.120	0.120	0.376
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.056	0.071	0.074	0.074	-0.099
Net Present Value at 7% Discount Rate ($Billions)		0.018	0.015	0.015	0.015	-0.122

Table 10B.2.88 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.015	0.0017	0.0027	0.0062	0.0062	0.0092
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0010	0.0015	0.0022	0.0022	-0.0017
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	-0.0001	-0.0001	-0.0026

Table 10B.2.89 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.09	-1.09	-2.98
Operating Cost (Savings in TSLs) ($Billions)	4.06	0.449	0.851	1.73	1.73	2.47
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.305	0.487	0.639	0.639	-0.514
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.088	-0.0003	-0.0003	-0.733

Table 10B.2.90 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0027	0.0002	0.0005	0.0005	0.0005	0.0014
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.2.91 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.387	0.023	0.070	0.070	0.070	0.201
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.016	0.028	0.028	0.028	-0.011
Net Present Value at 7% Discount Rate ($Billions)		0.0040	0.0010	0.0010	0.0010	-0.044

10B.2.7.3 7 Percent Discount Rate

Table 10B.2.92 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
Operating Cost (Savings in TSLs) ($Billions)	19.99	2.06	4.11	4.35	7.00	6.91	7.57	10.13
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		3.92	7.82	8.39	13.37	12.66	11.12	-7.44
Net Present Value at 7% Discount Rate ($Billions)		0.800	1.59	1.74	2.74	2.43	1.25	-9.76

Table 10B.2.93 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
Operating Cost (Savings in TSLs) ($Billions)	7.94	3.03	3.10	3.59	5.16	5.27	5.81
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.01	7.61	9.87	8.05	1.23
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.78	1.80	2.04	1.04	-2.78

Table 10B.2.94 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
Operating Cost (Savings in TSLs) ($Billions)	1.67	0.173	0.337	0.623	0.623	0.990
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.379	0.589	0.744	0.744	-0.626
Net Present Value at 7% Discount Rate ($Billions)		0.093	0.104	0.016	0.016	-0.903

Table 10B.2.95 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	22.36	-0.525	-1.78	-1.79	-2.61	-3.03	-4.05	-12.11
Operating Cost (Savings in TSLs) ($Billions)	9.85	0.248	2.30	2.32	3.63	3.69	3.94	5.02
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.255	3.65	3.71	6.15	5.53	4.30	-8.09
Net Present Value at 7% Discount Rate ($Billions)		-0.276	0.517	0.536	1.02	0.662	-0.109	-7.09

Table 10B.2.96 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.92	-0.732	-0.732	-0.818	-1.65	-1.45	-2.27	-7.78
Operating Cost (Savings in TSLs) ($Billions)	10.14	1.81	1.81	2.02	3.37	3.21	3.63	5.11
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.18	4.18	4.68	7.22	7.13	6.82	0.650
Net Present Value at 7% Discount Rate ($Billions)		1.08	1.08	1.21	1.72	1.76	1.36	-2.67

Table 10B.2.97 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.462	0.0000	-0.137	-0.124	-0.216	-0.216	-0.474
Operating Cost (Savings in TSLs) ($Billions)	0.256	0.0000	0.074	0.125	0.170	0.170	0.190
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.040	0.146	0.106	0.106	-0.336
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.064	0.0016	-0.046	-0.046	-0.284

Table 10B.2.98 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.56	-1.18	-1.18	-1.66	-2.91	-4.01	-8.12
Operating Cost (Savings in TSLs) ($Billions)	7.68	3.03	3.03	3.46	4.99	5.10	5.62
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.05	7.47	9.76	7.94	1.57
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.84	1.80	2.08	1.09	-2.50

Table 10B.2.99 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0033
Operating Cost (Savings in TSLs) ($Billions)	0.0032	0.0003	0.0004	0.0005	0.0005	0.0018
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0007	0.0009	0.0011	0.0011	-0.0008
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0015

Table 10B.2.100 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.244
Operating Cost (Savings in TSLs) ($Billions)	0.220	0.019	0.037	0.039	0.039	0.122
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.056	0.071	0.074	0.074	-0.099
Net Present Value at 7% Discount Rate ($Billions)		0.018	0.015	0.015	0.015	-0.122

Table 10B.2.101 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0056
Operating Cost (Savings in TSLs) ($Billions)	0.0048	0.0005	0.0009	0.0020	0.0020	0.0030
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0010	0.0015	0.0022	0.0022	-0.0017
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	-0.0001	-0.0001	-0.0026

Table 10B.2.102 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.560	-0.560	-1.53
Operating Cost (Savings in TSLs) ($Billions)	1.31	0.145	0.275	0.559	0.559	0.798
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.305	0.487	0.639	0.639	-0.514
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.088	-0.0003	-0.0003	-0.733

Table 10B.2.103 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0004
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.2.104 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.125	0.0073	0.023	0.023	0.023	0.065
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.016	0.028	0.028	0.028	-0.011
Net Present Value at 7% Discount Rate ($Billions)		0.0040	0.0010	0.0010	0.0010	-0.044

10B.2.8 High Economic Growth Scenario

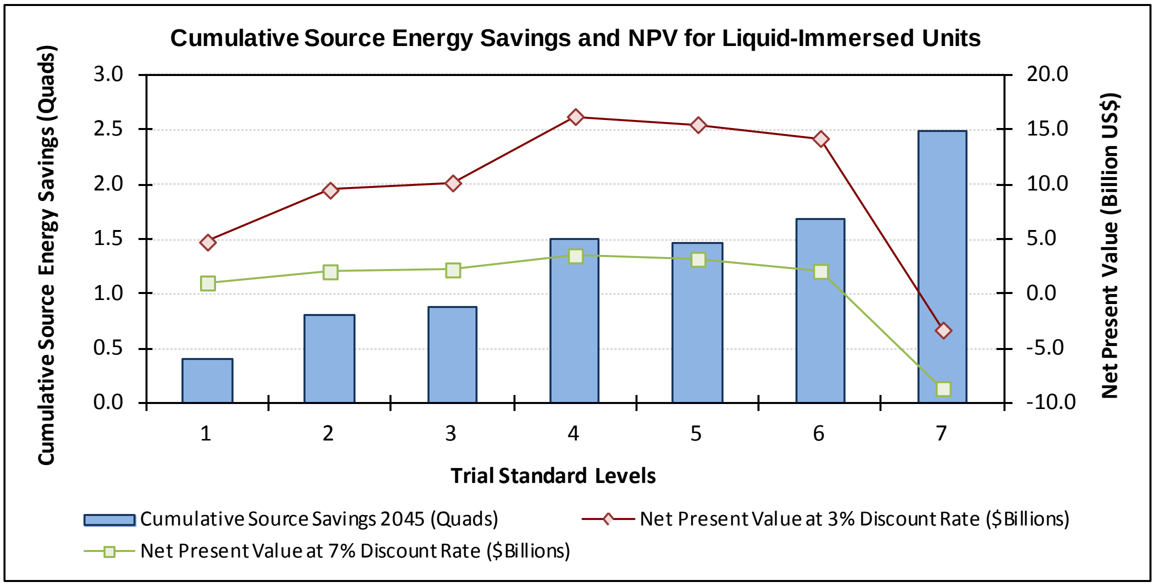

Figure 10B.2.13 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario

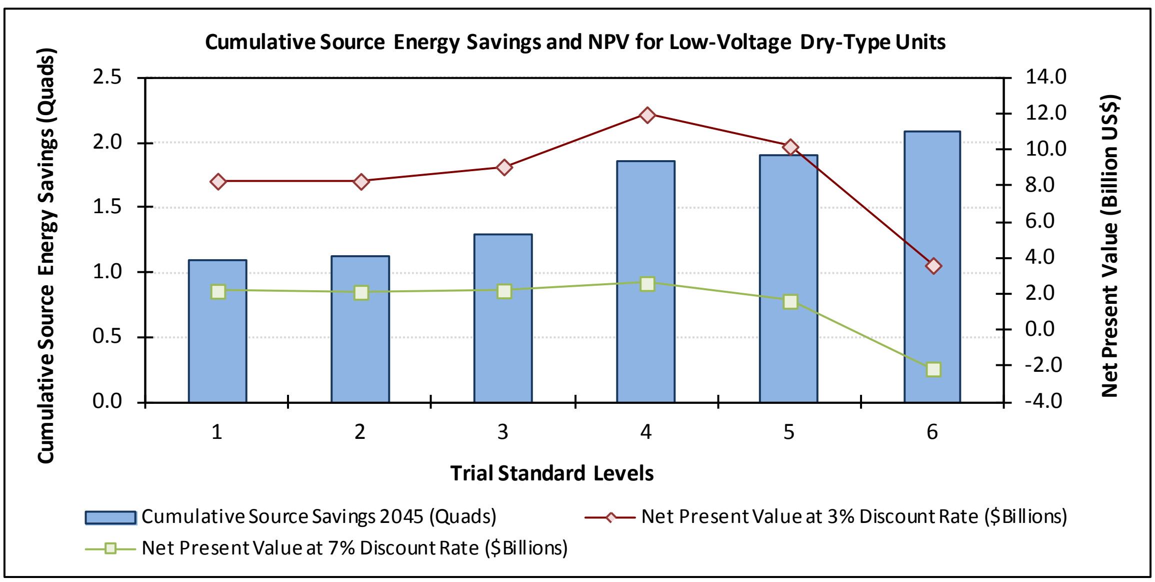

Figure 10B.2.14 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario

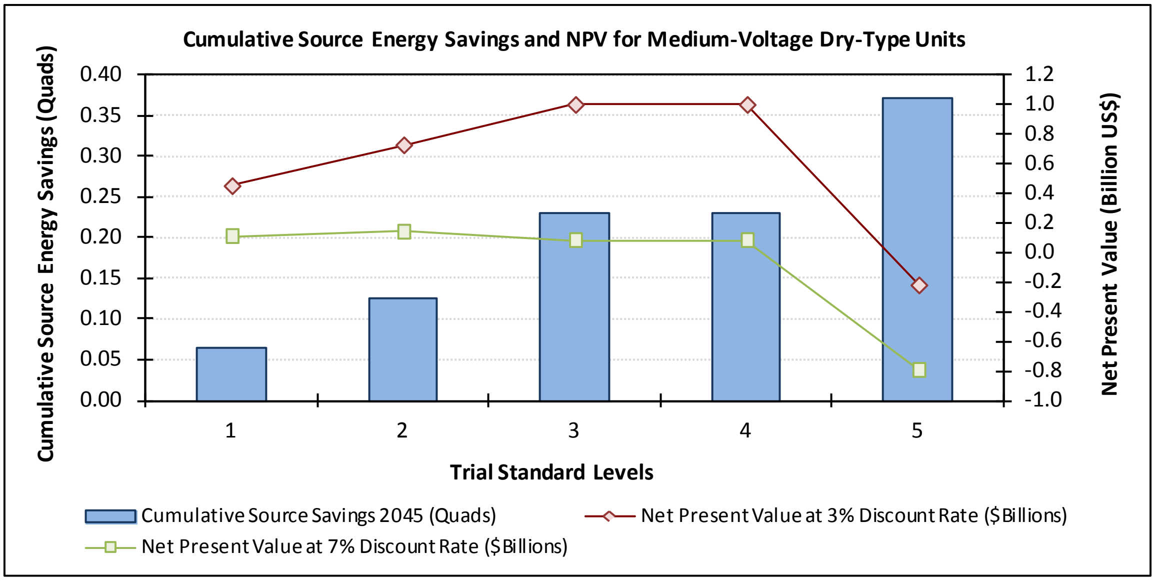

Figure 10B.2.15 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario

10B.2.8.2 3 Percent Discount Rate

Table 10B.2.105 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	63.05	-2.45	-4.91	-5.09	-8.32	-8.75	-12.34	-38.84
Operating Cost (Savings in TSLs) ($Billions)	70.18	7.22	14.42	15.27	24.56	24.25	26.58	35.56
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.77	9.51	10.18	16.24	15.50	14.24	-3.28
Net Present Value at 7% Discount Rate ($Billions)		1.03	2.05	2.23	3.51	3.20	2.09	-8.63

Table 10B.2.106 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	19.51	-2.30	-2.57	-3.48	-6.09	-8.23	-16.73
Operating Cost (Savings in TSLs) ($Billions)	27.79	10.59	10.85	12.56	18.07	18.44	20.34
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.28	9.08	11.98	10.20	3.61
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.12	2.20	2.61	1.62	-2.14

Table 10B.2.107 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.79	-0.154	-0.452	-1.18	-1.18	-3.69
Operating Cost (Savings in TSLs) ($Billions)	5.83	0.604	1.18	2.18	2.18	3.47
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.450	0.726	0.999	0.999	-0.221
Net Present Value at 7% Discount Rate ($Billions)		0.113	0.142	0.085	0.085	-0.793

Table 10B.2.108 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	43.68	-1.02	-3.48	-3.49	-5.10	-5.92	-7.90	-23.65
Operating Cost (Savings in TSLs) ($Billions)	34.57	0.872	8.07	8.16	12.74	12.97	13.83	17.62
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.153	4.59	4.67	7.64	7.05	5.92	-6.03
Net Present Value at 7% Discount Rate ($Billions)		-0.249	0.772	0.794	1.42	1.07	0.328	-6.53

Table 10B.2.109 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.22	-2.83	-4.44	-15.19
Operating Cost (Savings in TSLs) ($Billions)	35.61	6.35	6.35	7.11	11.82	11.28	12.75	17.94
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.92	4.92	5.51	8.61	8.45	8.31	2.75
Net Present Value at 7% Discount Rate ($Billions)		1.28	1.28	1.43	2.09	2.12	1.76	-2.10

Table 10B.2.110 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.900	0.0000	-0.268	-0.241	-0.421	-0.421	-0.923
Operating Cost (Savings in TSLs) ($Billions)	0.895	0.0000	0.257	0.438	0.596	0.596	0.665
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.010	0.198	0.175	0.175	-0.258
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.056	0.016	-0.027	-0.027	-0.263

Table 10B.2.111 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	18.61	-2.30	-2.30	-3.24	-5.67	-7.81	-15.81
Operating Cost (Savings in TSLs) ($Billions)	26.90	10.59	10.59	12.12	17.47	17.84	19.68
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.29	8.88	11.80	10.03	3.87
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.18	2.18	2.64	1.65	-1.87

Table 10B.2.112 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0065
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0016	0.0019	0.0019	0.0064
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0009	0.0011	0.0013	0.0013	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0002	0.0003	0.0003	-0.0013

Table 10B.2.113 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.475
Operating Cost (Savings in TSLs) ($Billions)	0.768	0.068	0.131	0.136	0.136	0.426
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.064	0.086	0.090	0.090	-0.049
Net Present Value at 7% Discount Rate ($Billions)		0.020	0.019	0.019	0.019	-0.109

Table 10B.2.114 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.017	0.0019	0.0031	0.0070	0.0070	0.010
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0013	0.0019	0.0030	0.0030	-0.0005
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0004	0.0002	0.0002	-0.0023

Table 10B.2.115 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.09	-1.09	-2.98
Operating Cost (Savings in TSLs) ($Billions)	4.59	0.508	0.963	1.96	1.96	2.79
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.364	0.600	0.868	0.868	-0.188
Net Present Value at 7% Discount Rate ($Billions)		0.087	0.119	0.062	0.062	-0.644

Table 10B.2.116 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0030	0.0002	0.0005	0.0005	0.0005	0.0016
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0003	0.0003	0.0003	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.2.117 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.439	0.026	0.079	0.079	0.079	0.227
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.019	0.037	0.037	0.037	0.016
Net Present Value at 7% Discount Rate ($Billions)		0.0049	0.0035	0.0035	0.0035	-0.036

10B.2.8.3 7 Percent Discount Rate

Table 10B.2.118 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
Operating Cost (Savings in TSLs) ($Billions)	22.21	2.29	4.56	4.83	7.77	7.68	8.41	11.25
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.77	9.51	10.18	16.24	15.50	14.24	-3.28
Net Present Value at 7% Discount Rate ($Billions)		1.03	2.05	2.23	3.51	3.20	2.09	-8.63

Table 10B.2.119 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
Operating Cost (Savings in TSLs) ($Billions)	8.82	3.36	3.44	3.99	5.73	5.85	6.46
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.28	9.08	11.98	10.20	3.61
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.12	2.20	2.61	1.62	-2.14

Table 10B.2.120 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
Operating Cost (Savings in TSLs) ($Billions)	1.85	0.192	0.374	0.693	0.693	1.10
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.450	0.726	0.999	0.999	-0.221
Net Present Value at 7% Discount Rate ($Billions)		0.113	0.142	0.085	0.085	-0.793

Table 10B.2.121 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	22.36	-0.525	-1.78	-1.79	-2.61	-3.03	-4.05	-12.11
Operating Cost (Savings in TSLs) ($Billions)	10.94	0.276	2.55	2.58	4.03	4.11	4.38	5.58
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.153	4.59	4.67	7.64	7.05	5.92	-6.03
Net Present Value at 7% Discount Rate ($Billions)		-0.249	0.772	0.794	1.42	1.07	0.328	-6.53

Table 10B.2.122 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.92	-0.732	-0.732	-0.818	-1.65	-1.45	-2.27	-7.78
Operating Cost (Savings in TSLs) ($Billions)	11.27	2.01	2.01	2.25	3.74	3.57	4.03	5.68
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.92	4.92	5.51	8.61	8.45	8.31	2.75
Net Present Value at 7% Discount Rate ($Billions)		1.28	1.28	1.43	2.09	2.12	1.76	-2.10

Table 10B.2.123 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.462	0.0000	-0.137	-0.124	-0.216	-0.216	-0.474
Operating Cost (Savings in TSLs) ($Billions)	0.284	0.0000	0.082	0.139	0.189	0.189	0.211
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.010	0.198	0.175	0.175	-0.258
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.056	0.016	-0.027	-0.027	-0.263

Table 10B.2.124 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.56	-1.18	-1.18	-1.66	-2.91	-4.01	-8.12
Operating Cost (Savings in TSLs) ($Billions)	8.54	3.36	3.36	3.85	5.54	5.66	6.25
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.29	8.88	11.80	10.03	3.87
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.18	2.18	2.64	1.65	-1.87

Table 10B.2.125 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0033
Operating Cost (Savings in TSLs) ($Billions)	0.0035	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0009	0.0011	0.0013	0.0013	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0002	0.0003	0.0003	-0.0013

Table 10B.2.126 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.244
Operating Cost (Savings in TSLs) ($Billions)	0.244	0.021	0.042	0.043	0.043	0.135
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.064	0.086	0.090	0.090	-0.049
Net Present Value at 7% Discount Rate ($Billions)		0.020	0.019	0.019	0.019	-0.109

Table 10B.2.127 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0056
Operating Cost (Savings in TSLs) ($Billions)	0.0054	0.0006	0.0010	0.0022	0.0022	0.0033
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0013	0.0019	0.0030	0.0030	-0.0005
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0004	0.0002	0.0002	-0.0023

Table 10B.2.128 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.560	-0.560	-1.53
Operating Cost (Savings in TSLs) ($Billions)	1.46	0.161	0.306	0.621	0.621	0.887
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.364	0.600	0.868	0.868	-0.188
Net Present Value at 7% Discount Rate ($Billions)		0.087	0.119	0.062	0.062	-0.644

Table 10B.2.129 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0010	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0003	0.0003	0.0003	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.2.130 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.139	0.0081	0.025	0.025	0.025	0.072
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.019	0.037	0.037	0.037	0.016
Net Present Value at 7% Discount Rate ($Billions)		0.0049	0.0035	0.0035	0.0035	-0.036

10B.2.9 Low Price Trend Scenario

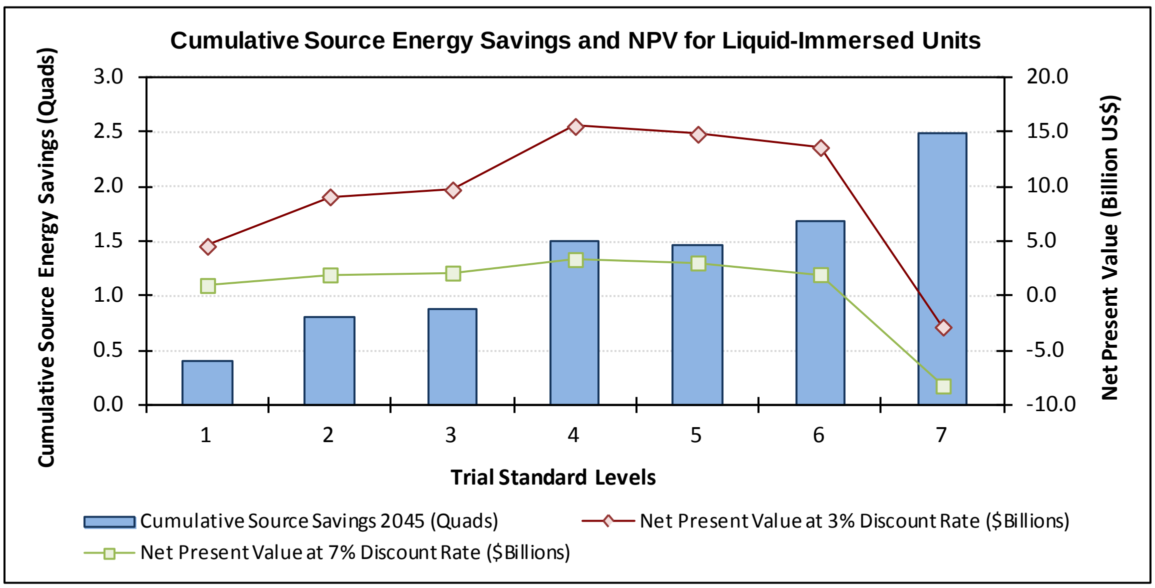

Figure 10B.2.16 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario

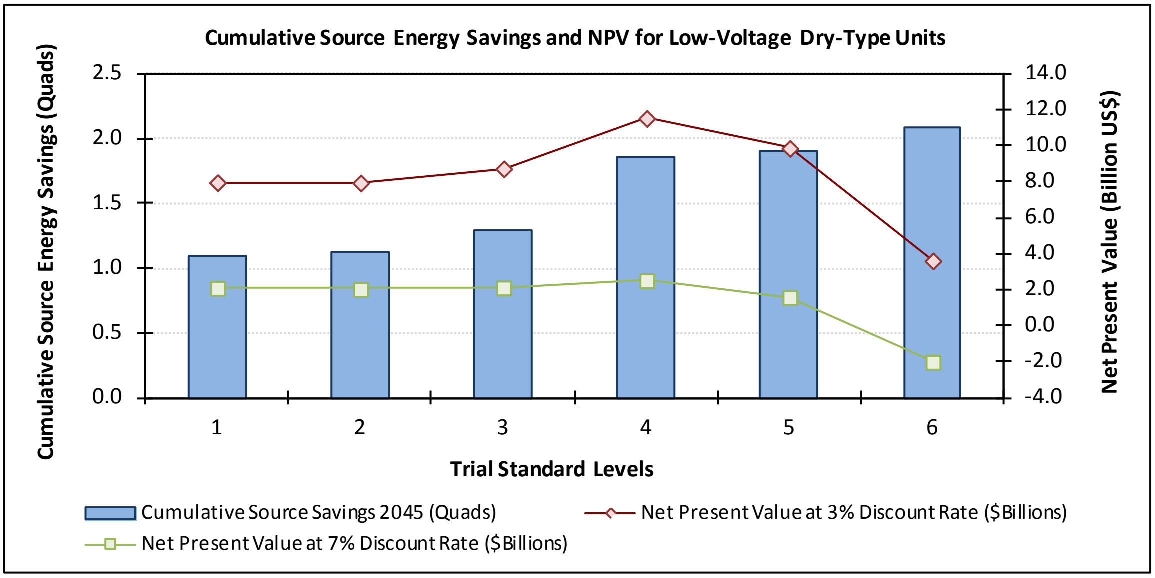

Figure 10B.2.17 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario

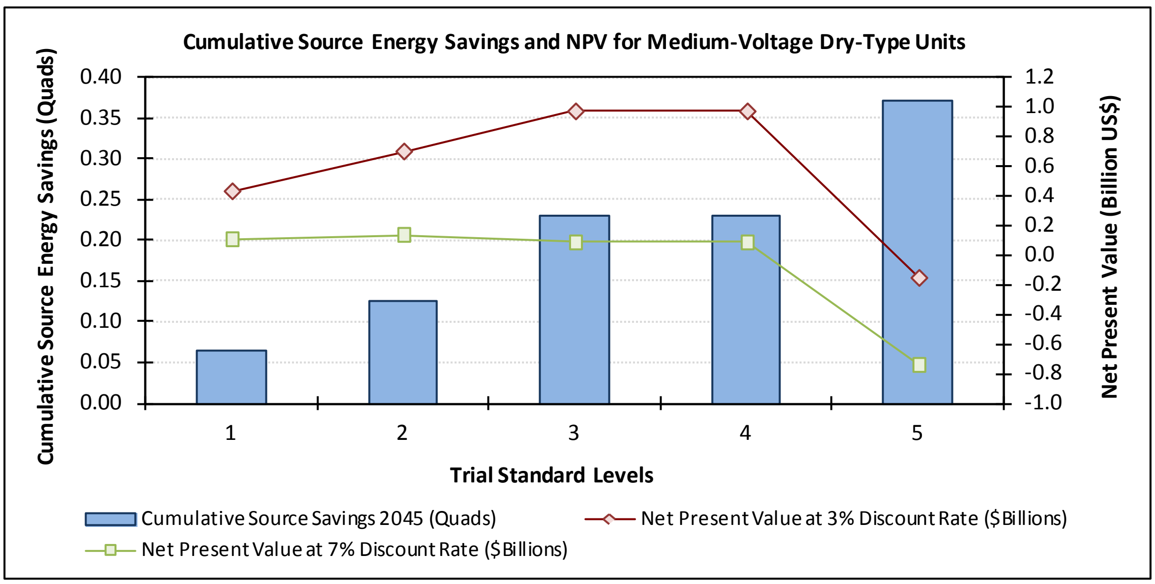

Figure 10B.2.18 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario

10B.2.9.2 3 Percent Discount Rate

Table 10B.2.131 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	60.90	-2.32	-4.67	-4.84	-7.91	-8.33	-11.76	-36.77
Operating Cost (Savings in TSLs) ($Billions)	67.01	6.90	13.77	14.58	23.45	23.16	25.37	33.95
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.58	9.10	9.73	15.54	14.83	13.61	-2.82
Net Present Value at 7% Discount Rate ($Billions)		0.990	1.96	2.13	3.36	3.05	1.99	-8.20

Table 10B.2.132 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	18.72	-2.14	-2.40	-3.24	-5.70	-7.72	-15.79
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.11	10.36	11.99	17.25	17.61	19.42
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.96	8.75	11.55	9.88	3.63
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.05	2.13	2.53	1.60	-2.00

Table 10B.2.133 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.52	-0.144	-0.423	-1.11	-1.11	-3.46
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.08	2.08	3.31
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.433	0.702	0.973	0.973	-0.153
Net Present Value at 7% Discount Rate ($Billions)		0.109	0.139	0.087	0.087	-0.741

Table 10B.2.134 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	42.38	-0.978	-3.33	-3.34	-4.88	-5.67	-7.58	-22.51
Operating Cost (Savings in TSLs) ($Billions)	33.01	0.833	7.71	7.79	12.16	12.39	13.20	16.82
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.145	4.37	4.45	7.28	6.72	5.62	-5.68
Net Present Value at 7% Discount Rate ($Billions)		-0.240	0.728	0.748	1.34	1.01	0.282	-6.27

Table 10B.2.135 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	18.52	-1.34	-1.34	-1.50	-3.03	-2.66	-4.18	-14.26
Operating Cost (Savings in TSLs) ($Billions)	34.00	6.06	6.06	6.79	11.29	10.77	12.17	17.13
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.72	4.72	5.29	8.26	8.11	8.00	2.86
Net Present Value at 7% Discount Rate ($Billions)		1.23	1.23	1.38	2.02	2.04	1.70	-1.94

Table 10B.2.136 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.868	0.0000	-0.262	-0.227	-0.400	-0.400	-0.878
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.246	0.419	0.569	0.569	0.635
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.016	0.191	0.170	0.170	-0.243
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.015	-0.026	-0.026	-0.252

Table 10B.2.137 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	17.85	-2.14	-2.14	-3.01	-5.30	-7.32	-14.91
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.11	10.11	11.57	16.68	17.04	18.79
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.98	8.56	11.38	9.71	3.88
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.11	2.12	2.56	1.62	-1.74

Table 10B.2.138 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0086	-0.0001	-0.0005	-0.0006	-0.0006	-0.0061
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0013	0.0013	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0012

Table 10B.2.139 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.570	-0.0033	-0.042	-0.043	-0.043	-0.446
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.407
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.083	0.086	0.086	-0.039
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.018	0.019	0.019	-0.102

Table 10B.2.140 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.014	-0.0006	-0.0011	-0.0037	-0.0037	-0.010
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0067	0.0067	0.0099
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0018	0.0029	0.0029	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0003	0.0002	0.0002	-0.0021

Table 10B.2.141 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.58	-0.134	-0.340	-1.02	-1.02	-2.80
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.920	1.87	1.87	2.67
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.351	0.580	0.846	0.846	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.085	0.116	0.065	0.065	-0.602

Table 10B.2.142 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0023	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.2.143 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.339	-0.0060	-0.039	-0.039	-0.039	-0.198
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.217
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.036	0.036	0.036	0.019
Net Present Value at 7% Discount Rate ($Billions)		0.0047	0.0036	0.0036	0.0036	-0.034

10B.2.9.3 7 Percent Discount Rate

Table 10B.2.144 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	31.33	-1.20	-2.41	-2.50	-4.08	-4.29	-6.06	-18.97
Operating Cost (Savings in TSLs) ($Billions)	21.25	2.19	4.37	4.62	7.44	7.34	8.05	10.77
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.58	9.10	9.73	15.54	14.83	13.61	-2.82
Net Present Value at 7% Discount Rate ($Billions)		0.990	1.96	2.13	3.36	3.05	1.99	-8.20

Table 10B.2.145 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	9.67	-1.11	-1.24	-1.68	-2.95	-4.00	-8.17
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.81	5.49	5.60	6.18
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.96	8.75	11.55	9.88	3.63
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.05	2.13	2.53	1.60	-2.00

Table 10B.2.146 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.34	-0.075	-0.219	-0.575	-0.575	-1.79
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.358	0.663	0.663	1.05
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.433	0.702	0.973	0.973	-0.153
Net Present Value at 7% Discount Rate ($Billions)		0.109	0.139	0.087	0.087	-0.741

Table 10B.2.147 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	21.79	-0.504	-1.72	-1.72	-2.51	-2.92	-3.90	-11.60
Operating Cost (Savings in TSLs) ($Billions)	10.47	0.264	2.44	2.47	3.86	3.93	4.19	5.33
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.145	4.37	4.45	7.28	6.72	5.62	-5.68
Net Present Value at 7% Discount Rate ($Billions)		-0.240	0.728	0.748	1.34	1.01	0.282	-6.27

Table 10B.2.148 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.54	-0.693	-0.693	-0.775	-1.56	-1.37	-2.16	-7.37
Operating Cost (Savings in TSLs) ($Billions)	10.78	1.92	1.92	2.15	3.58	3.42	3.86	5.43
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.72	4.72	5.29	8.26	8.11	8.00	2.86
Net Present Value at 7% Discount Rate ($Billions)		1.23	1.23	1.38	2.02	2.04	1.70	-1.94

Table 10B.2.149 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.448	0.0000	-0.135	-0.118	-0.207	-0.207	-0.454
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.078	0.133	0.181	0.181	0.202
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.016	0.191	0.170	0.170	-0.243
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.015	-0.026	-0.026	-0.252

Table 10B.2.150 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.22	-1.11	-1.11	-1.56	-2.75	-3.79	-7.72
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.68	5.31	5.42	5.98
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.98	8.56	11.38	9.71	3.88
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.11	2.12	2.56	1.62	-1.74

Table 10B.2.151 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0044	0.0000	-0.0002	-0.0003	-0.0003	-0.0032
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0013	0.0013	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0012

Table 10B.2.152 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.295	-0.0017	-0.022	-0.022	-0.022	-0.231
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.129
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.083	0.086	0.086	-0.039
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.018	0.019	0.019	-0.102

Table 10B.2.153 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0074	-0.0003	-0.0006	-0.0019	-0.0019	-0.0053
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0018	0.0029	0.0029	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0003	0.0002	0.0002	-0.0021

Table 10B.2.154 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.85	-0.070	-0.176	-0.530	-0.530	-1.45
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.595	0.595	0.848
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.351	0.580	0.846	0.846	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.085	0.116	0.065	0.065	-0.602

Table 10B.2.155 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0012	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.2.156 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.176	-0.0031	-0.020	-0.020	-0.020	-0.103
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.036	0.036	0.036	0.019
Net Present Value at 7% Discount Rate ($Billions)		0.0047	0.0036	0.0036	0.0036	-0.034

10B.2.10 High Price Trend Scenario

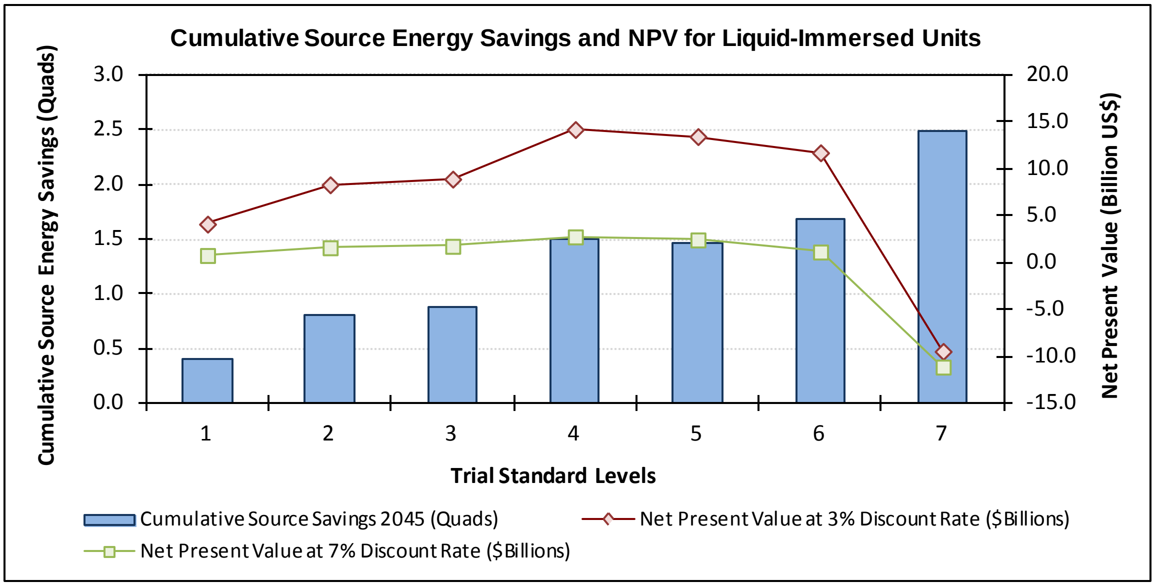

Figure 10B.2.19 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario

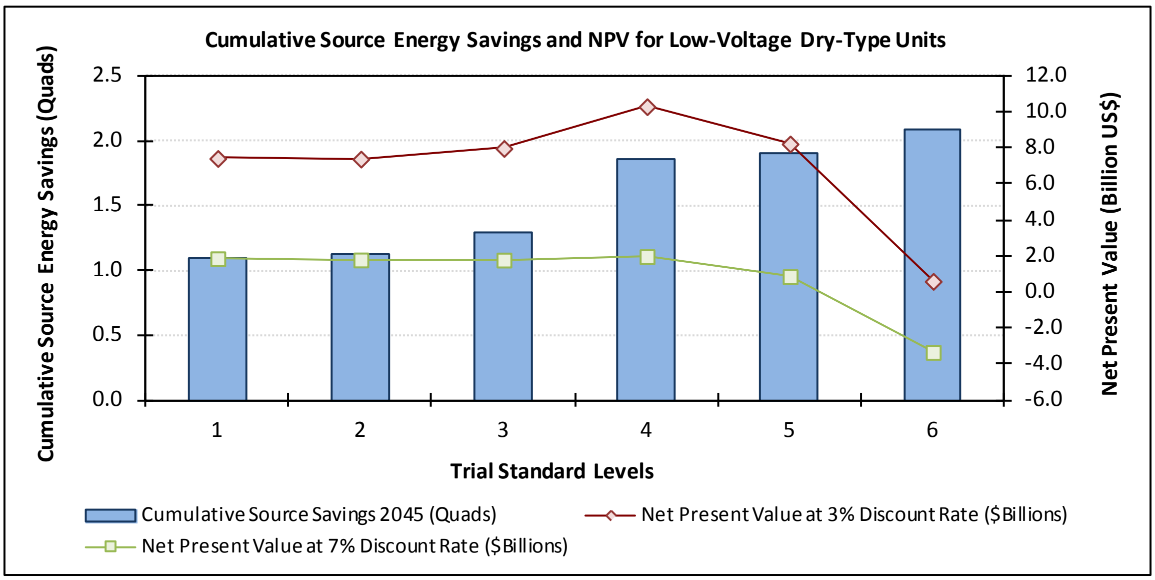

Figure 10B.2.20 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario

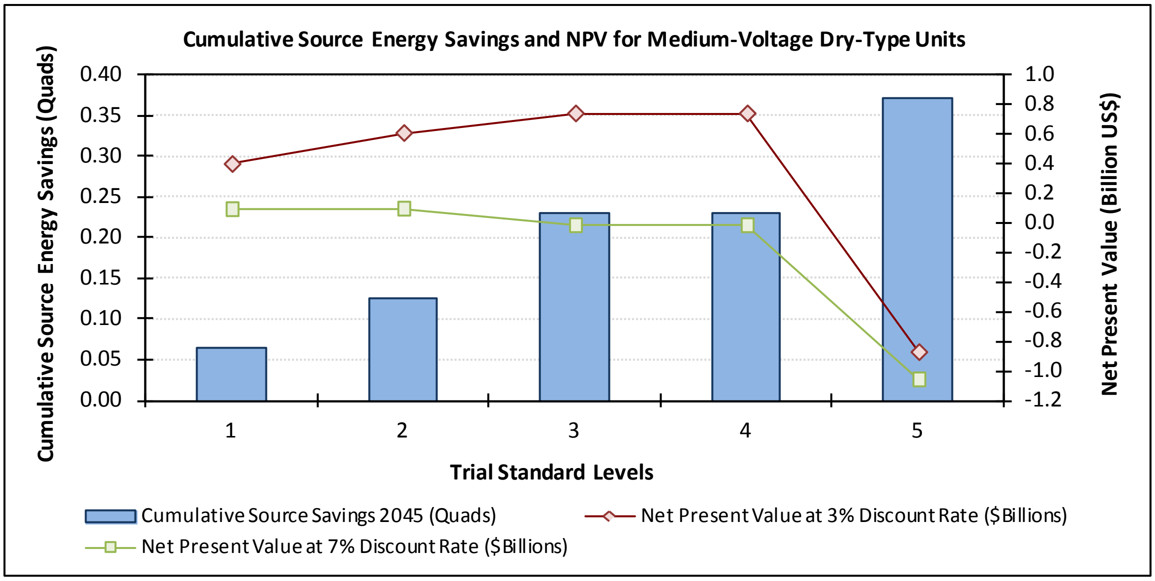

Figure 10B.2.21 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario

10B.2.10.2 3 Percent Discount Rate

Table 10B.2.157 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	67.78	-2.75	-5.43	-5.63	-9.22	-9.68	-13.62	-43.38
Operating Cost (Savings in TSLs) ($Billions)	67.01	6.90	13.77	14.58	23.45	23.16	25.37	33.95
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.15	8.34	8.94	14.23	13.48	11.76	-9.43
Net Present Value at 7% Discount Rate ($Billions)		0.801	1.63	1.78	2.79	2.46	1.17	-11.10

Table 10B.2.158 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	21.24	-2.68	-2.96	-3.99	-6.93	-9.36	-18.80
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.11	10.36	11.99	17.25	17.61	19.42
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.40	7.99	10.31	8.25	0.618
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.81	1.80	1.99	0.879	-3.32

Table 10B.2.159 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	5.40	-0.177	-0.516	-1.34	-1.34	-4.18
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.08	2.08	3.31
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.400	0.609	0.742	0.742	-0.873
Net Present Value at 7% Discount Rate ($Billions)		0.094	0.098	-0.014	-0.014	-1.06

Table 10B.2.160 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	46.54	-1.13	-3.81	-3.82	-5.58	-6.48	-8.61	-26.16
Operating Cost (Savings in TSLs) ($Billions)	33.01	0.833	7.71	7.79	12.16	12.39	13.20	16.82
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.295	3.90	3.97	6.58	5.91	4.59	-9.34
Net Present Value at 7% Discount Rate ($Billions)		-0.306	0.520	0.539	1.03	0.653	-0.169	-7.87

Table 10B.2.161 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	21.24	-1.62	-1.62	-1.81	-3.63	-3.20	-5.01	-17.22
Operating Cost (Savings in TSLs) ($Billions)	34.00	6.06	6.06	6.79	11.29	10.77	12.17	17.13
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.44	4.44	4.98	7.65	7.58	7.17	-0.095
Net Present Value at 7% Discount Rate ($Billions)		1.11	1.11	1.24	1.75	1.81	1.34	-3.23

Table 10B.2.162 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.972	0.0000	-0.280	-0.270	-0.468	-0.468	-1.02
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.246	0.419	0.569	0.569	0.635
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.035	0.148	0.101	0.101	-0.387
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.065	-0.0034	-0.056	-0.056	-0.315

Table 10B.2.163 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	20.27	-2.68	-2.68	-3.72	-6.47	-8.89	-17.78
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.11	10.11	11.57	16.68	17.04	18.79
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.44	7.85	10.21	8.14	1.01
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.87	1.81	2.05	0.935	-3.01

Table 10B.2.164 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.010	-0.0001	-0.0006	-0.0007	-0.0007	-0.0074
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0009	0.0011	0.0011	-0.0012
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0018

Table 10B.2.165 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.678	-0.0040	-0.050	-0.052	-0.052	-0.538
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.407
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.075	0.078	0.078	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.014	0.015	0.015	-0.142

Table 10B.2.166 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.017	-0.0008	-0.0014	-0.0045	-0.0045	-0.012
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0067	0.0067	0.0099
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0011	0.0016	0.0021	0.0021	-0.0024
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	-0.0002	-0.0002	-0.0031

Table 10B.2.167 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	4.28	-0.165	-0.415	-1.24	-1.24	-3.38
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.920	1.87	1.87	2.67
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.320	0.504	0.633	0.633	-0.714
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.083	-0.029	-0.029	-0.857

Table 10B.2.168 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0028	0.0000	-0.0003	-0.0003	-0.0003	-0.0016
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0002
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0004

Table 10B.2.169 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.406	-0.0071	-0.048	-0.048	-0.048	-0.241
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.217
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.017	0.028	0.028	0.028	-0.024
Net Present Value at 7% Discount Rate ($Billions)		0.0042	-0.0001	-0.0001	-0.0001	-0.052

10B.2.10.3 7 Percent Discount Rate

Table 10B.2.170 Liquid-Immersed Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	34.34	-1.39	-2.74	-2.84	-4.65	-4.88	-6.88	-21.87
Operating Cost (Savings in TSLs) ($Billions)	21.25	2.19	4.37	4.62	7.44	7.34	8.05	10.77
Cumulative Source Savings 2045 (Quads)		0.405	0.814	0.882	1.49	1.47	1.69	2.50
Net Present Value at 3% Discount Rate ($Billions)		4.15	8.34	8.94	14.23	13.48	11.76	-9.43
Net Present Value at 7% Discount Rate ($Billions)		0.801	1.63	1.78	2.79	2.46	1.17	-11.10

Table 10B.2.171 LVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.78	-1.35	-1.49	-2.01	-3.50	-4.72	-9.50
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.81	5.49	5.60	6.18
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.40	7.99	10.31	8.25	0.618
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.81	1.80	1.99	0.879	-3.32

Table 10B.2.172 MVDT Transformers, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.72	-0.089	-0.260	-0.677	-0.677	-2.11
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.358	0.663	0.663	1.05
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.400	0.609	0.742	0.742	-0.873
Net Present Value at 7% Discount Rate ($Billions)		0.094	0.098	-0.014	-0.014	-1.06

Table 10B.2.173 Equipment Class 1, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	23.61	-0.570	-1.92	-1.93	-2.82	-3.28	-4.36	-13.20
Operating Cost (Savings in TSLs) ($Billions)	10.47	0.264	2.44	2.47	3.86	3.93	4.19	5.33
Cumulative Source Savings 2045 (Quads)		0.076	0.486	0.490	0.776	0.806	0.885	1.25
Net Present Value at 3% Discount Rate ($Billions)		-0.295	3.90	3.97	6.58	5.91	4.59	-9.34
Net Present Value at 7% Discount Rate ($Billions)		-0.306	0.520	0.539	1.03	0.653	-0.169	-7.87

Table 10B.2.174 Equipment Class 2, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	10.73	-0.816	-0.816	-0.912	-1.83	-1.61	-2.52	-8.66
Operating Cost (Savings in TSLs) ($Billions)	10.78	1.92	1.92	2.15	3.58	3.42	3.86	5.43
Cumulative Source Savings 2045 (Quads)		0.329	0.329	0.392	0.716	0.666	0.803	1.24
Net Present Value at 3% Discount Rate ($Billions)		4.44	4.44	4.98	7.65	7.58	7.17	-0.095
Net Present Value at 7% Discount Rate ($Billions)		1.11	1.11	1.24	1.75	1.81	1.34	-3.23

Table 10B.2.175 Equipment Class 3, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.494	0.0000	-0.143	-0.137	-0.237	-0.237	-0.517
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.078	0.133	0.181	0.181	0.202
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.035	0.148	0.101	0.101	-0.387
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.065	-0.0034	-0.056	-0.056	-0.315

Table 10B.2.176 Equipment Class 4, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	10.28	-1.35	-1.35	-1.88	-3.26	-4.48	-8.98
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.68	5.31	5.42	5.98
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.44	7.85	10.21	8.14	1.01
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.87	1.81	2.05	0.935	-3.01

Table 10B.2.177 Equipment Class 5, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0051	0.0000	-0.0003	-0.0003	-0.0003	-0.0037
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0009	0.0011	0.0011	-0.0012
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0018

Table 10B.2.178 Equipment Class 6, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.343	-0.0020	-0.025	-0.026	-0.026	-0.272
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.129
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.075	0.078	0.078	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.014	0.015	0.015	-0.142

Table 10B.2.179 Equipment Class 7, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0086	-0.0004	-0.0007	-0.0023	-0.0023	-0.0062
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0011	0.0016	0.0021	0.0021	-0.0024
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	-0.0002	-0.0002	-0.0031

Table 10B.2.180 Equipment Class 8, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	2.16	-0.083	-0.209	-0.624	-0.624	-1.71
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.595	0.595	0.848
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.320	0.504	0.633	0.633	-0.714
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.083	-0.029	-0.029	-0.857

Table 10B.2.181 Equipment Class 9, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0014	0.0000	-0.0002	-0.0002	-0.0002	-0.0008
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0002
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0004

Table 10B.2.182 Equipment Class 10, 0 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.205	-0.0036	-0.024	-0.024	-0.024	-0.121
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.017	0.028	0.028	0.028	-0.024
Net Present Value at 7% Discount Rate ($Billions)		0.0042	-0.0001	-0.0001	-0.0001	-0.052

10B.3 1 PERCENT LOAD GROWTH, LIQUID-IMMERSED (0 PERCENT DRY-TYPE)

10B.3.11 Low Price Elasticity Scenario

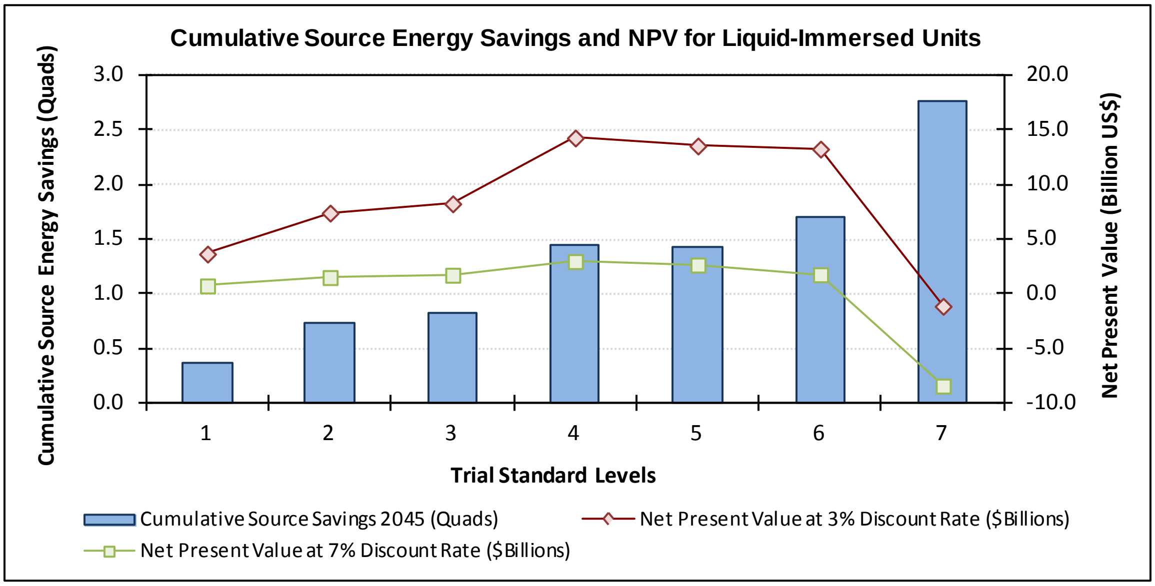

Figure 10B.3.1 Liquid-Immersed Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario

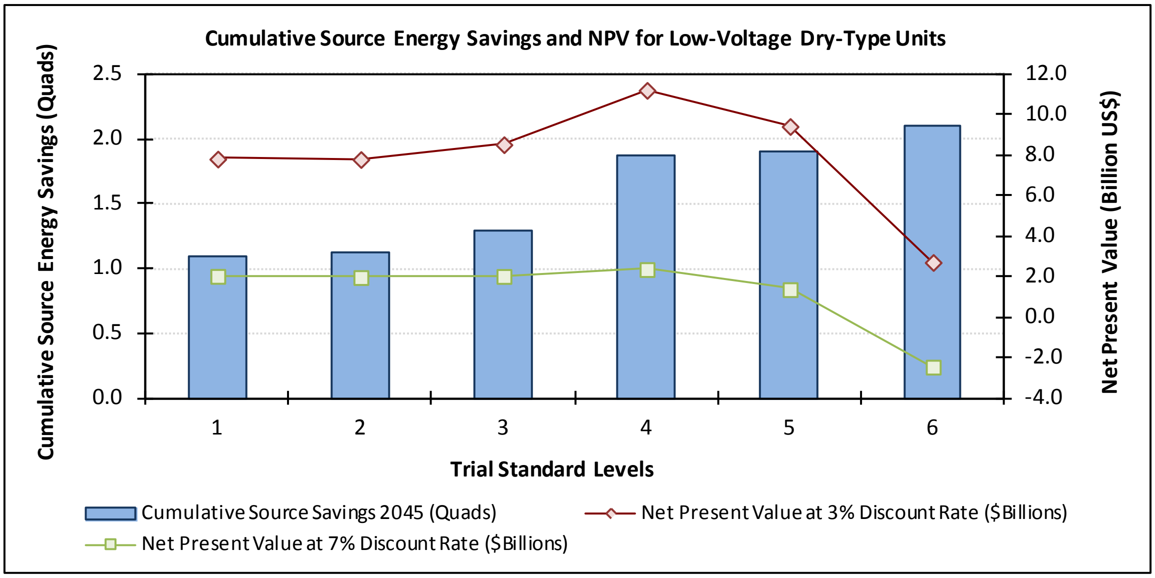

Figure 10B.3.2 LVDT Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario

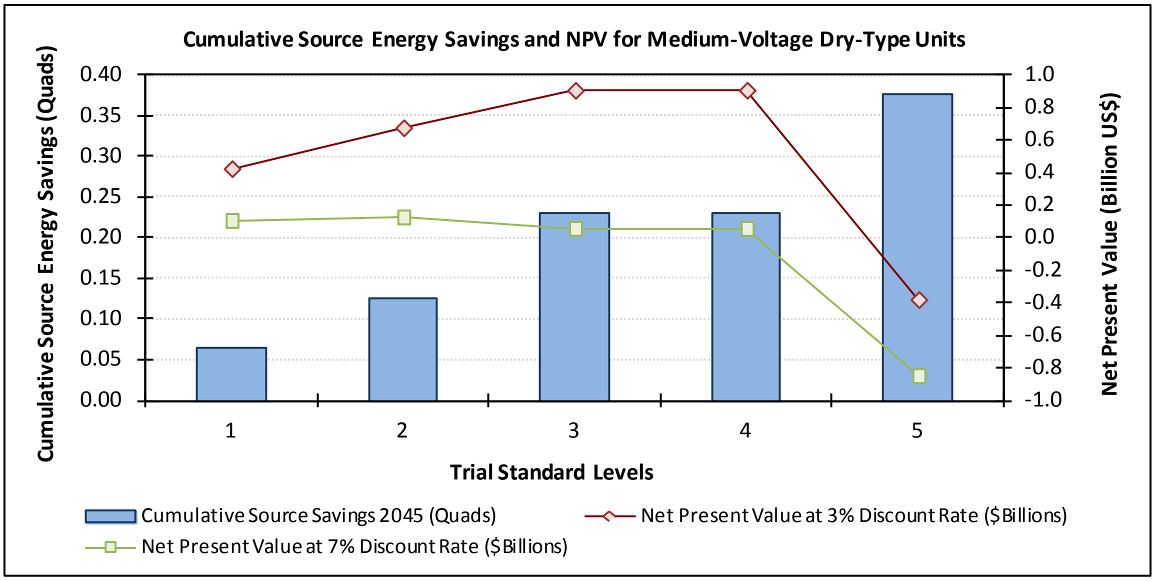

Figure 10B.3.3 MVDT Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario

10B.3.11.2 3 Percent Discount Rate

Table 10B.3.1 Liquid-Immersed Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
Equipment Cost ($Billions)	63.05	-2.46	-4.92	-5.11	-8.36	-8.80	-12.43	-39.64
Operating Cost (Savings in TSLs) ($Billions)	75.69	6.13	12.34	13.37	22.65	22.36	25.70	38.53
Cumulative Source Savings 2045 (Quads)		0.364	0.738	0.818	1.45	1.43	1.71	2.75
Net Present Value at 3% Discount Rate ($Billions)		3.67	7.42	8.27	14.29	13.56	13.27	-1.11
Net Present Value at 7% Discount Rate ($Billions)		0.752	1.52	1.73	2.98	2.67	1.77	-8.41

Table 10B.3.2 LVDT Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.617	0.617	0.617	0.617	0.617	0.617
Equipment Cost ($Billions)	19.51	-2.31	-2.58	-3.49	-6.12	-8.29	-16.94
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.14	10.39	12.03	17.34	17.73	19.67
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.30	1.87	1.91	2.10
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.81	8.54	11.22	9.44	2.72
Net Present Value at 7% Discount Rate ($Billions)		2.04	1.98	2.03	2.37	1.38	-2.44

Table 10B.3.3 MVDT Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.223	0.223	0.223
Equipment Cost ($Billions)	4.79	-0.155	-0.453	-1.19	-1.19	-3.73
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.09	2.09	3.35
Cumulative Source Savings 2045 (Quads)		0.064	0.127	0.231	0.231	0.377
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.674	0.905	0.905	-0.383
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.056	0.056	-0.850

Table 10B.3.4 Equipment Class 1, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.801	0.801	0.801	0.801	0.801	0.801	0.801
Equipment Cost ($Billions)	43.68	-1.03	-3.49	-3.50	-5.12	-5.95	-7.96	-24.08
Operating Cost (Savings in TSLs) ($Billions)	36.93	1.16	7.37	7.44	11.80	12.27	13.50	19.35
Cumulative Source Savings 2045 (Quads)		0.093	0.468	0.472	0.757	0.800	0.903	1.39
Net Present Value at 3% Discount Rate ($Billions)		0.132	3.88	3.94	6.67	6.31	5.54	-4.72
Net Present Value at 7% Discount Rate ($Billions)		-0.186	0.581	0.599	1.15	0.858	0.189	-6.38

Table 10B.3.5 Equipment Class 2, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.24	-2.84	-4.47	-15.56
Operating Cost (Savings in TSLs) ($Billions)	38.76	4.97	4.97	5.93	10.85	10.09	12.20	19.17
Cumulative Source Savings 2045 (Quads)		0.270	0.270	0.346	0.693	0.630	0.806	1.36
Net Present Value at 3% Discount Rate ($Billions)		3.54	3.54	4.33	7.61	7.25	7.73	3.61
Net Present Value at 7% Discount Rate ($Billions)		0.938	0.938	1.14	1.83	1.81	1.59	-2.03

Table 10B.3.6 Equipment Class 3, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.022	0.022	0.022	0.022	0.022
Equipment Cost ($Billions)	0.900	0.0000	-0.269	-0.242	-0.424	-0.424	-0.936
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.247	0.421	0.574	0.574	0.644
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.062	0.062	0.069
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.179	0.149	0.149	-0.292
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.060	0.0096	-0.035	-0.035	-0.276

Table 10B.3.7 Equipment Class 4, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.596	0.596	0.596	0.596	0.596	0.596
Equipment Cost ($Billions)	18.61	-2.31	-2.31	-3.25	-5.70	-7.87	-16.01
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.14	10.14	11.61	16.77	17.16	19.02
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.81	1.85	2.04
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.83	8.36	11.07	9.29	3.02
Net Present Value at 7% Discount Rate ($Billions)		2.04	2.04	2.02	2.41	1.42	-2.17

Table 10B.3.8 Equipment Class 5, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0066
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.3.9 Equipment Class 6, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.481
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.412
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.081	0.084	0.084	-0.069
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.116

Table 10B.3.10 Equipment Class 7, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0030	0.0067	0.0067	0.010
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0025

Table 10B.3.11 Equipment Class 8, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.173	0.173	0.173
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.10	-1.10	-3.02
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.921	1.88	1.88	2.70
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.206	0.206	0.304
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.557	0.783	0.783	-0.318
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.690

Table 10B.3.12 Equipment Class 9, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0015
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.3.13 Equipment Class 10, 1 Percent Load Growth, Low Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.218
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0086	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0025	0.0024	-0.040

10B.3.11.37 Percent Discount Rate

Table 10B.3.14 Liquid-Immersed Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.95	1.95	1.95	1.95
Equipment Cost ($Billions)	32.28	-1.26	-2.52	-2.61	-4.28	-4.50	-6.37	-20.29
Operating Cost (Savings in TSLs) ($Billions)	23.26	2.01	4.04	4.35	7.26	7.17	8.14	11.89
Cumulative Source Savings 2045 (Quads)		0.364	0.738	0.818	1.45	1.43	1.71	2.75
Net Present Value at 3% Discount Rate ($Billions)		3.67	7.42	8.27	14.29	13.56	13.27	-1.11
Net Present Value at 7% Discount Rate ($Billions)		0.752	1.52	1.73	2.98	2.67	1.77	-8.41

Table 10B.3.15 LVDT Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.617	0.617	0.617	0.617	0.617	0.617
Equipment Cost ($Billions)	10.02	-1.19	-1.32	-1.79	-3.14	-4.26	-8.70
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.83	5.52	5.64	6.26
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.30	1.87	1.91	2.10
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.81	8.54	11.22	9.44	2.72
Net Present Value at 7% Discount Rate ($Billions)		2.04	1.98	2.03	2.37	1.38	-2.44

Table 10B.3.16 MVDT Transformers, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.223	0.223	0.223
Equipment Cost ($Billions)	2.46	-0.079	-0.233	-0.610	-0.610	-1.91
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.359	0.666	0.666	1.06
Cumulative Source Savings 2045 (Quads)		0.064	0.127	0.231	0.231	0.377
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.674	0.905	0.905	-0.383
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.056	0.056	-0.850

Table 10B.3.17 Equipment Class 1, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.801	0.801	0.801	0.801	0.801	0.801	0.801
Equipment Cost ($Billions)	22.36	-0.525	-1.79	-1.79	-2.62	-3.05	-4.07	-12.33
Operating Cost (Savings in TSLs) ($Billions)	11.37	0.339	2.37	2.39	3.78	3.91	4.26	5.95
Cumulative Source Savings 2045 (Quads)		0.093	0.468	0.472	0.757	0.800	0.903	1.39
Net Present Value at 3% Discount Rate ($Billions)		0.132	3.88	3.94	6.67	6.31	5.54	-4.72
Net Present Value at 7% Discount Rate ($Billions)		-0.186	0.581	0.599	1.15	0.858	0.189	-6.38

Table 10B.3.18 Equipment Class 2, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Equipment Cost ($Billions)	9.92	-0.734	-0.734	-0.821	-1.66	-1.46	-2.29	-7.97
Operating Cost (Savings in TSLs) ($Billions)	11.88	1.67	1.67	1.96	3.49	3.26	3.88	5.94
Cumulative Source Savings 2045 (Quads)		0.270	0.270	0.346	0.693	0.630	0.806	1.36
Net Present Value at 3% Discount Rate ($Billions)		3.54	3.54	4.33	7.61	7.25	7.73	3.61
Net Present Value at 7% Discount Rate ($Billions)		0.938	0.938	1.14	1.83	1.81	1.59	-2.03

Table 10B.3.19 Equipment Class 3, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.022	0.022	0.022	0.022	0.022
Equipment Cost ($Billions)	0.462	0.0000	-0.138	-0.124	-0.218	-0.218	-0.481
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.079	0.134	0.183	0.183	0.205
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.062	0.062	0.069
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.179	0.149	0.149	-0.292
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.060	0.0096	-0.035	-0.035	-0.276

Table 10B.3.20 Equipment Class 4, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.596	0.596	0.596	0.596	0.596	0.596
Equipment Cost ($Billions)	9.56	-1.19	-1.19	-1.67	-2.92	-4.04	-8.22
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.69	5.33	5.46	6.05
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.81	1.85	2.04
Net Present Value at 3% Discount Rate ($Billions)		7.83	7.83	8.36	11.07	9.29	3.02
Net Present Value at 7% Discount Rate ($Billions)		2.04	2.04	2.02	2.41	1.42	-2.17

Table 10B.3.21 Equipment Class 5, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0034
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.3.22 Equipment Class 6, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.247
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.131
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.081	0.084	0.084	-0.069
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.116

Table 10B.3.23 Equipment Class 7, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0021	-0.0021	-0.0057
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0025

Table 10B.3.24 Equipment Class 8, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.173	0.173	0.173
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.562	-0.562	-1.55
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.598	0.598	0.858
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.206	0.206	0.304
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.557	0.783	0.783	-0.318
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.690

Table 10B.3.25 Equipment Class 9, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0008
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.3.26 Equipment Class 10, 1 Percent Load Growth, Low Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0086	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0025	0.0024	-0.040

10B.3.12 Medium Price Elasticity Scenario

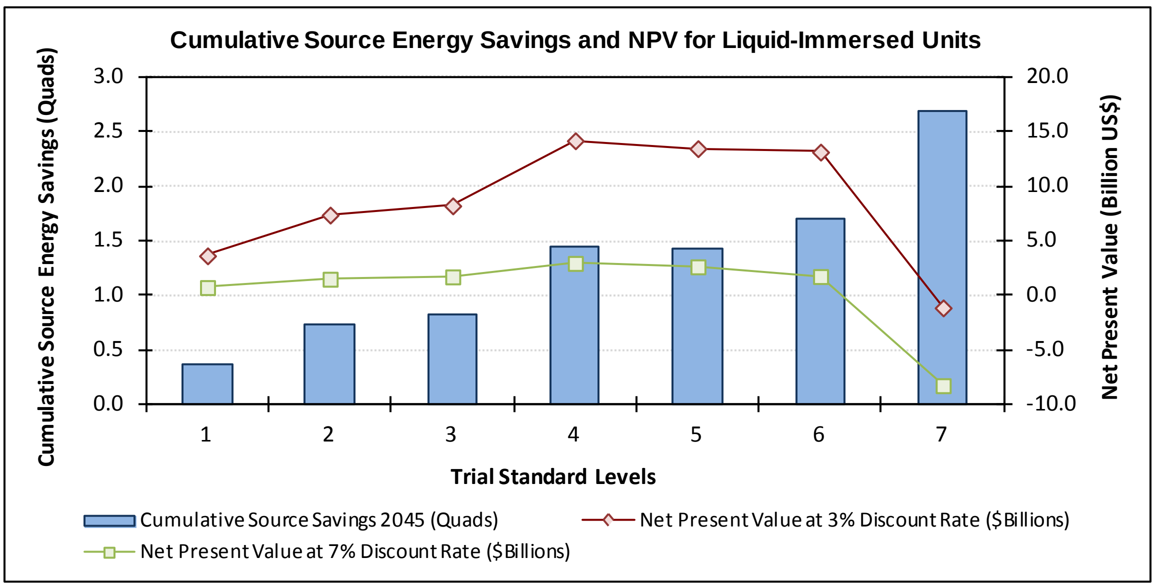

Figure 10B.3.4 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario

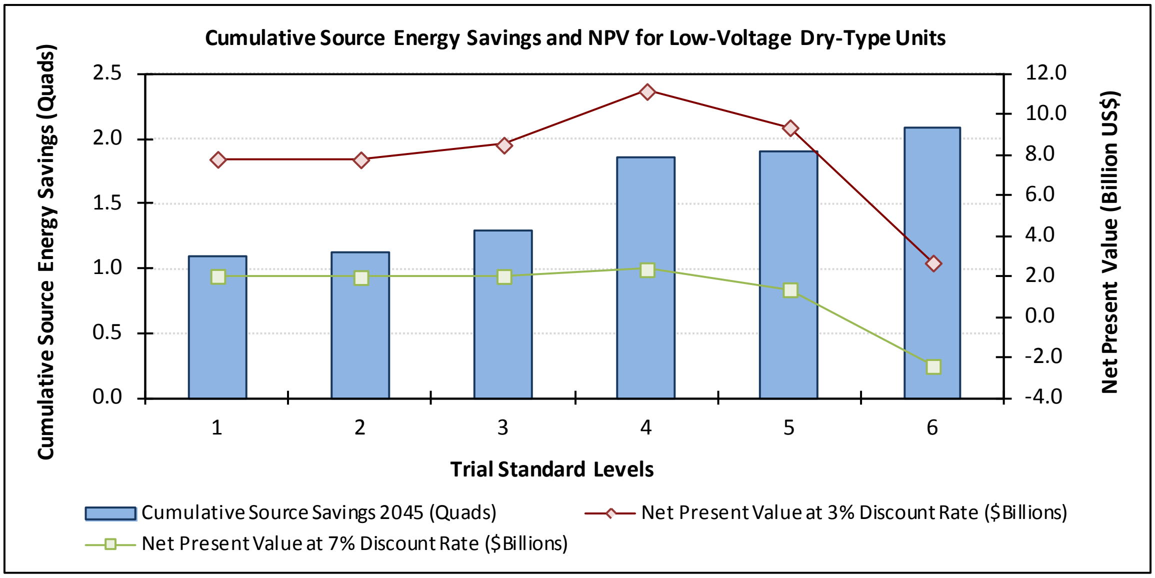

Figure 10B.3.5 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario

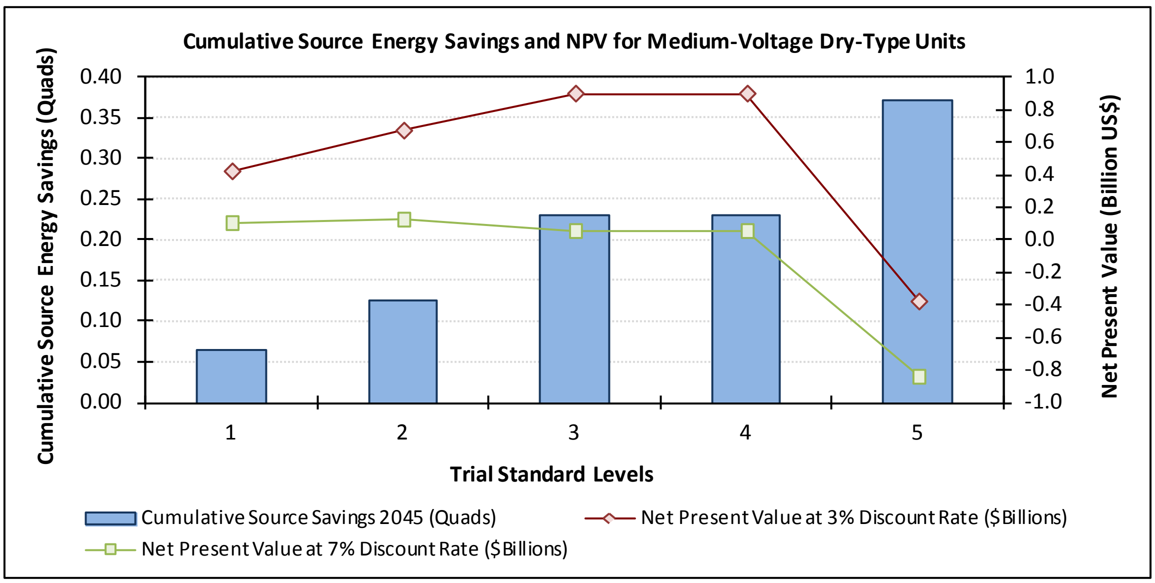

Figure 10B.3.6 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario

10B.3.12.2 3 Percent Discount Rate

Table 10B.3.27 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	63.05	-2.45	-4.91	-5.09	-8.32	-8.75	-12.34	-38.84
Operating Cost (Savings in TSLs) ($Billions)	75.69	6.11	12.30	13.33	22.53	22.24	25.51	37.72
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.66	7.39	8.24	14.21	13.48	13.17	-1.11
Net Present Value at 7% Discount Rate ($Billions)		0.749	1.51	1.73	2.96	2.65	1.76	-8.25

Table 10B.3.28 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	19.51	-2.30	-2.57	-3.48	-6.09	-8.23	-16.73
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.11	10.36	11.99	17.25	17.61	19.42
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.79	8.51	11.16	9.37	2.69
Net Present Value at 7% Discount Rate ($Billions)		2.03	1.97	2.03	2.36	1.37	-2.41

Table 10B.3.29 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.79	-0.154	-0.452	-1.18	-1.18	-3.69
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.08	2.08	3.31
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.673	0.901	0.901	-0.378
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.055	0.055	-0.841

Table 10B.3.30 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	43.68	-1.02	-3.48	-3.49	-5.10	-5.92	-7.90	-23.65
Operating Cost (Savings in TSLs) ($Billions)	36.93	1.16	7.35	7.42	11.74	12.20	13.41	19.01
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.132	3.87	3.93	6.64	6.28	5.51	-4.64
Net Present Value at 7% Discount Rate ($Billions)		-0.186	0.579	0.597	1.15	0.853	0.188	-6.27

Table 10B.3.31 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.22	-2.83	-4.44	-15.19
Operating Cost (Savings in TSLs) ($Billions)	38.76	4.96	4.96	5.91	10.78	10.03	12.10	18.72
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.53	3.53	4.31	7.57	7.21	7.66	3.53
Net Present Value at 7% Discount Rate ($Billions)		0.935	0.935	1.13	1.82	1.80	1.57	-1.98

Table 10B.3.32 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.900	0.0000	-0.268	-0.241	-0.421	-0.421	-0.923
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.246	0.419	0.569	0.569	0.635
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.178	0.148	0.148	-0.288
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.059	0.0095	-0.035	-0.035	-0.272

Table 10B.3.33 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	18.61	-2.30	-2.30	-3.24	-5.67	-7.81	-15.81
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.11	10.11	11.57	16.68	17.04	18.79
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.81	8.33	11.01	9.22	2.98
Net Present Value at 7% Discount Rate ($Billions)		2.03	2.03	2.02	2.40	1.41	-2.14

Table 10B.3.34 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0065
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.3.35 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.475
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.407
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.080	0.084	0.084	-0.068
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.115

Table 10B.3.36 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0067	0.0067	0.0099
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0024

Table 10B.3.37 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.09	-1.09	-2.98
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.920	1.87	1.87	2.67
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.556	0.779	0.779	-0.314
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.682

Table 10B.3.38 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.3.39 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.217
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0024	0.0024	-0.040

10B.3.12.3 7 Percent Discount Rate

Table 10B.3.40 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
Operating Cost (Savings in TSLs) ($Billions)	23.26	2.01	4.03	4.33	7.22	7.13	8.08	11.64
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.66	7.39	8.24	14.21	13.48	13.17	-1.11
Net Present Value at 7% Discount Rate ($Billions)		0.749	1.51	1.73	2.96	2.65	1.76	-8.25

Table 10B.3.41 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.81	5.49	5.60	6.18
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.79	8.51	11.16	9.37	2.69
Net Present Value at 7% Discount Rate ($Billions)		2.03	1.97	2.03	2.36	1.37	-2.41

Table 10B.3.42 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.358	0.663	0.663	1.05
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.423	0.673	0.901	0.901	-0.378
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.126	0.055	0.055	-0.841

Table 10B.3.43 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	22.36	-0.525	-1.78	-1.79	-2.61	-3.03	-4.05	-12.11
Operating Cost (Savings in TSLs) ($Billions)	11.37	0.339	2.36	2.38	3.76	3.89	4.23	5.84
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.132	3.87	3.93	6.64	6.28	5.51	-4.64
Net Present Value at 7% Discount Rate ($Billions)		-0.186	0.579	0.597	1.15	0.853	0.188	-6.27

Table 10B.3.44 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.92	-0.732	-0.732	-0.818	-1.65	-1.45	-2.27	-7.78
Operating Cost (Savings in TSLs) ($Billions)	11.88	1.67	1.67	1.95	3.46	3.25	3.84	5.80
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.53	3.53	4.31	7.57	7.21	7.66	3.53
Net Present Value at 7% Discount Rate ($Billions)		0.935	0.935	1.13	1.82	1.80	1.57	-1.98

Table 10B.3.45 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.462	0.0000	-0.137	-0.124	-0.216	-0.216	-0.474
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.078	0.133	0.181	0.181	0.202
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.022	0.178	0.148	0.148	-0.288
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.059	0.0095	-0.035	-0.035	-0.272

Table 10B.3.46 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.56	-1.18	-1.18	-1.66	-2.91	-4.01	-8.12
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.68	5.31	5.42	5.98
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.81	7.81	8.33	11.01	9.22	2.98
Net Present Value at 7% Discount Rate ($Billions)		2.03	2.03	2.02	2.40	1.41	-2.14

Table 10B.3.47 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0033
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0004
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0014

Table 10B.3.48 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.244
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.129
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.080	0.084	0.084	-0.068
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.018	0.018	-0.115

Table 10B.3.49 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0056
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0027	0.0027	-0.0010
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0024

Table 10B.3.50 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.560	-0.560	-1.53
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.595	0.595	0.848
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.341	0.556	0.779	0.779	-0.314
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.106	0.035	0.035	-0.682

Table 10B.3.51 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.3.52 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.034	0.034	0.034	0.0056
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0025	0.0024	0.0024	-0.040

10B.3.13 High Price Elasticity Scenario

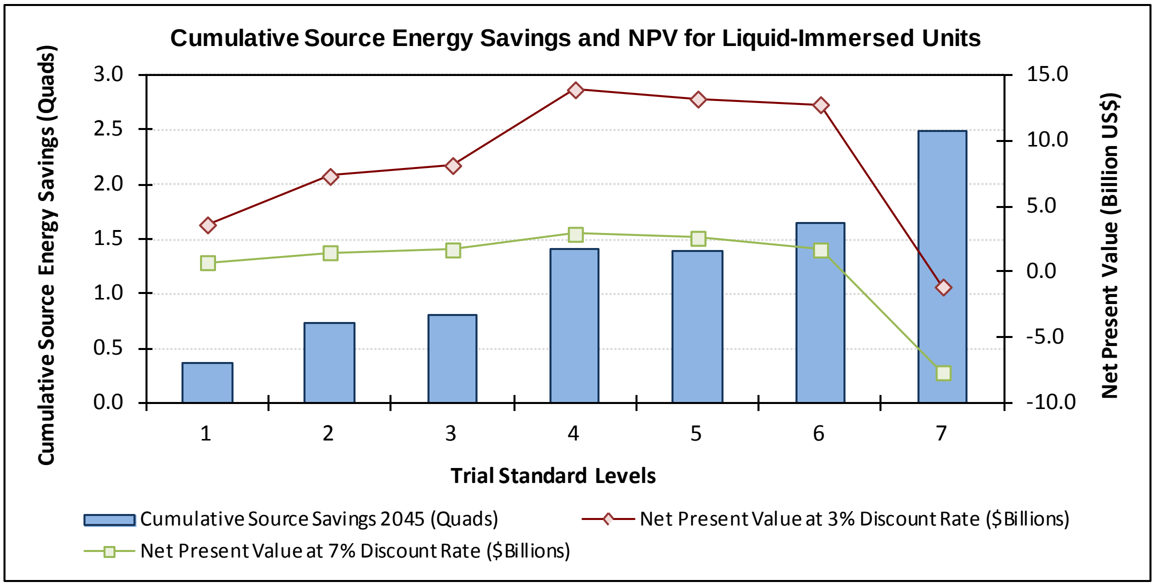

Figure 10B.3.7 Liquid-Immersed Transformers, 1 Percent Load Growth, High Price Elasticity Scenario

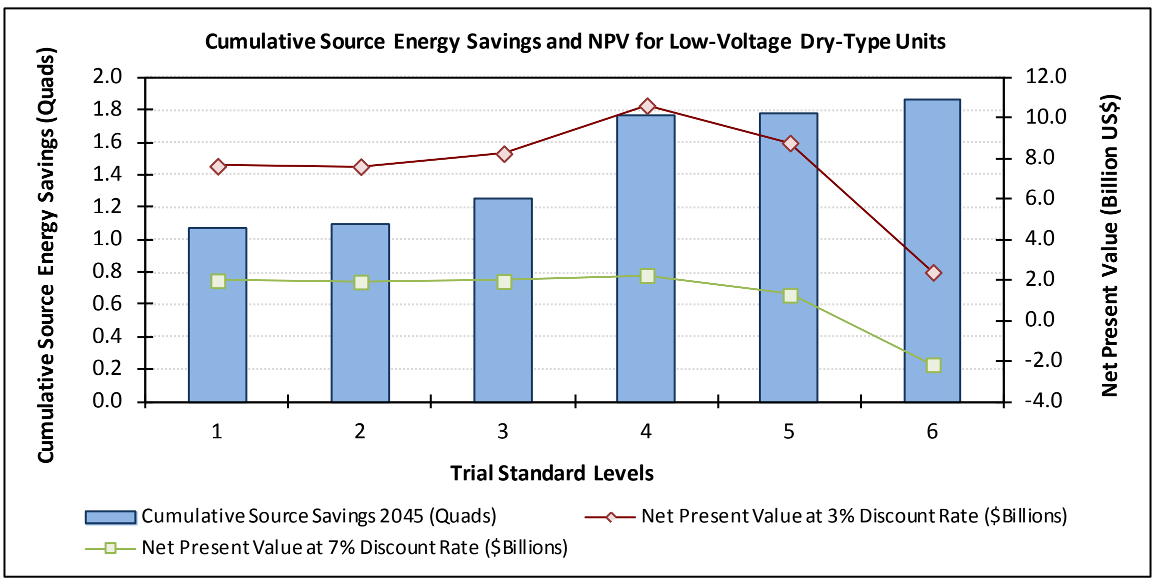

Figure 10B.3.8 LVDT Transformers, 1 Percent Load Growth, High Price Elasticity Scenario

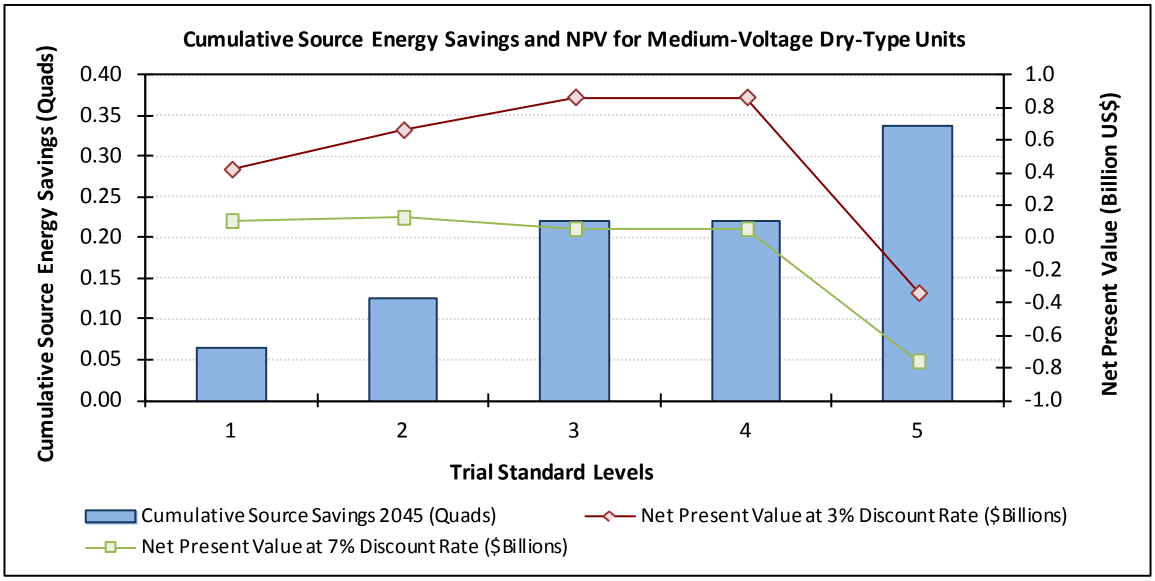

Figure 10B.3.9 MVDT Transformers, 1 Percent Load Growth, High Price Elasticity Scenario

10B.3.13.2 3 Percent Discount Rate

Table 10B.3.53 Liquid-Immersed Transformers, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.93	1.93	1.92	1.90	1.90	1.88	1.76
Equipment Cost ($Billions)	63.05	-2.43	-4.85	-5.03	-8.15	-8.57	-11.99	-35.88
Operating Cost (Savings in TSLs) ($Billions)	75.69	6.05	12.16	13.16	22.06	21.77	24.76	34.77
Cumulative Source Savings 2045 (Quads)		0.359	0.727	0.806	1.41	1.39	1.65	2.49
Net Present Value at 3% Discount Rate ($Billions)		3.62	7.31	8.14	13.91	13.20	12.77	-1.12
Net Present Value at 7% Discount Rate ($Billions)		0.739	1.50	1.71	2.90	2.59	1.70	-7.65

Table 10B.3.54 LVDT Transformers, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.603	0.602	0.597	0.585	0.575	0.545
Equipment Cost ($Billions)	19.51	-2.26	-2.51	-3.37	-5.79	-7.73	-14.95
Operating Cost (Savings in TSLs) ($Billions)	26.54	9.90	10.14	11.64	16.43	16.52	17.36
Cumulative Source Savings 2045 (Quads)		1.07	1.09	1.25	1.77	1.78	1.86
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.63	8.27	10.63	8.79	2.41
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.93	1.97	2.25	1.29	-2.15

Table 10B.3.55 MVDT Transformers, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.222	0.220	0.214	0.214	0.200
Equipment Cost ($Billions)	4.79	-0.153	-0.445	-1.13	-1.13	-3.34
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.574	1.11	2.00	2.00	3.00
Cumulative Source Savings 2045 (Quads)		0.063	0.124	0.220	0.220	0.338
Net Present Value at 3% Discount Rate ($Billions)		0.420	0.662	0.864	0.864	-0.340
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.124	0.054	0.053	-0.760

Table 10B.3.56 Equipment Class 1, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.797	0.788	0.788	0.783	0.780	0.774	0.733
Equipment Cost ($Billions)	43.68	-1.02	-3.44	-3.45	-5.01	-5.80	-7.70	-22.05
Operating Cost (Savings in TSLs) ($Billions)	36.93	1.15	7.26	7.33	11.54	11.96	13.06	17.73
Cumulative Source Savings 2045 (Quads)		0.093	0.461	0.465	0.740	0.780	0.873	1.28
Net Present Value at 3% Discount Rate ($Billions)		0.131	3.82	3.88	6.53	6.15	5.36	-4.33
Net Present Value at 7% Discount Rate ($Billions)		-0.185	0.572	0.590	1.13	0.836	0.183	-5.85

Table 10B.3.57 Equipment Class 2, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.14	1.14	1.14	1.12	1.12	1.11	1.03
Equipment Cost ($Billions)	19.37	-1.41	-1.41	-1.58	-3.14	-2.77	-4.29	-13.83
Operating Cost (Savings in TSLs) ($Billions)	38.76	4.90	4.90	5.84	10.52	9.82	11.71	17.04
Cumulative Source Savings 2045 (Quads)		0.266	0.266	0.341	0.672	0.613	0.773	1.21
Net Present Value at 3% Discount Rate ($Billions)		3.49	3.49	4.26	7.38	7.05	7.41	3.21
Net Present Value at 7% Discount Rate ($Billions)		0.925	0.925	1.12	1.77	1.76	1.52	-1.80

Table 10B.3.58 Equipment Class 3, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.020	0.021	0.020	0.020	0.019
Equipment Cost ($Billions)	0.900	0.0000	-0.255	-0.231	-0.393	-0.393	-0.812
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.235	0.401	0.531	0.531	0.558
Cumulative Source Savings 2045 (Quads)		0.0000	0.025	0.044	0.057	0.057	0.060
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.021	0.170	0.138	0.138	-0.253
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.0091	-0.033	-0.033	-0.239

Table 10B.3.59 Equipment Class 4, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.582	0.582	0.577	0.565	0.555	0.526
Equipment Cost ($Billions)	18.61	-2.26	-2.26	-3.14	-5.40	-7.33	-14.14
Operating Cost (Savings in TSLs) ($Billions)	25.68	9.90	9.90	11.24	15.90	15.99	16.80
Cumulative Source Savings 2045 (Quads)		1.07	1.07	1.21	1.71	1.72	1.80
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.65	8.10	10.50	8.66	2.66
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.99	1.96	2.28	1.32	-1.92

Table 10B.3.60 Equipment Class 5, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0059
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0056
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0006
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0013

Table 10B.3.61 Equipment Class 6, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.032	0.032	0.032	0.029
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.428
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.123	0.128	0.128	0.366
Cumulative Source Savings 2045 (Quads)		0.0071	0.014	0.015	0.015	0.042
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.079	0.082	0.082	-0.061
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.017	0.017	-0.103

Table 10B.3.62 Equipment Class 7, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0038	-0.0038	-0.0099
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0064	0.0064	0.0090
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0010
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0026	0.0026	-0.0009
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0022

Table 10B.3.63 Equipment Class 8, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.172	0.170	0.165	0.165	0.154
Equipment Cost ($Billions)	3.80	-0.143	-0.358	-1.04	-1.04	-2.68
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.482	0.905	1.79	1.79	2.40
Cumulative Source Savings 2045 (Quads)		0.053	0.101	0.196	0.196	0.271
Net Present Value at 3% Discount Rate ($Billions)		0.339	0.547	0.745	0.745	-0.283
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.104	0.033	0.033	-0.614

Table 10B.3.64 Equipment Class 9, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0013
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0014
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.3.65 Equipment Class 10, 1 Percent Load Growth, High Price Elasticity Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.041	-0.207
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.075	0.075	0.074	0.212
Cumulative Source Savings 2045 (Quads)		0.0029	0.0084	0.0084	0.0084	0.023
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.033	0.033	0.033	0.0054
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0024	0.0024	0.0024	-0.039

10B.3.13.3 7 Percent Discount Rate

Table 10B.3.66 Liquid-Immersed Transformers, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.93	1.93	1.92	1.90	1.90	1.88	1.76
Equipment Cost ($Billions)	32.28	-1.25	-2.48	-2.57	-4.17	-4.39	-6.14	-18.37
Operating Cost (Savings in TSLs) ($Billions)	23.26	1.99	3.98	4.28	7.07	6.98	7.84	10.73
Cumulative Source Savings 2045 (Quads)		0.359	0.727	0.806	1.41	1.39	1.65	2.49
Net Present Value at 3% Discount Rate ($Billions)		3.62	7.31	8.14	13.91	13.20	12.77	-1.12
Net Present Value at 7% Discount Rate ($Billions)		0.739	1.50	1.71	2.90	2.59	1.70	-7.65

Table 10B.3.67 LVDT Transformers, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.603	0.602	0.597	0.585	0.575	0.545
Equipment Cost ($Billions)	10.02	-1.16	-1.29	-1.73	-2.97	-3.97	-7.68
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.15	3.22	3.70	5.23	5.25	5.52
Cumulative Source Savings 2045 (Quads)		1.07	1.09	1.25	1.77	1.78	1.86
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.63	8.27	10.63	8.79	2.41
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.93	1.97	2.25	1.29	-2.15

Table 10B.3.68 MVDT Transformers, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.222	0.220	0.214	0.214	0.200
Equipment Cost ($Billions)	2.46	-0.079	-0.229	-0.582	-0.582	-1.71
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.182	0.352	0.635	0.635	0.953
Cumulative Source Savings 2045 (Quads)		0.063	0.124	0.220	0.220	0.338
Net Present Value at 3% Discount Rate ($Billions)		0.420	0.662	0.864	0.864	-0.340
Net Present Value at 7% Discount Rate ($Billions)		0.104	0.124	0.054	0.053	-0.760

Table 10B.3.69 Equipment Class 1, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.797	0.788	0.788	0.783	0.780	0.774	0.733
Equipment Cost ($Billions)	22.36	-0.523	-1.76	-1.77	-2.57	-2.97	-3.94	-11.29
Operating Cost (Savings in TSLs) ($Billions)	11.37	0.338	2.33	2.36	3.69	3.81	4.12	5.45
Cumulative Source Savings 2045 (Quads)		0.093	0.461	0.465	0.740	0.780	0.873	1.28
Net Present Value at 3% Discount Rate ($Billions)		0.131	3.82	3.88	6.53	6.15	5.36	-4.33
Net Present Value at 7% Discount Rate ($Billions)		-0.185	0.572	0.590	1.13	0.836	0.183	-5.85

Table 10B.3.70 Equipment Class 2, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.14	1.14	1.14	1.12	1.12	1.11	1.03
Equipment Cost ($Billions)	9.92	-0.723	-0.723	-0.808	-1.61	-1.42	-2.20	-7.08
Operating Cost (Savings in TSLs) ($Billions)	11.88	1.65	1.65	1.93	3.38	3.18	3.72	5.28
Cumulative Source Savings 2045 (Quads)		0.266	0.266	0.341	0.672	0.613	0.773	1.21
Net Present Value at 3% Discount Rate ($Billions)		3.49	3.49	4.26	7.38	7.05	7.41	3.21
Net Present Value at 7% Discount Rate ($Billions)		0.925	0.925	1.12	1.77	1.76	1.52	-1.80

Table 10B.3.71 Equipment Class 3, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.020	0.021	0.020	0.020	0.019
Equipment Cost ($Billions)	0.462	0.0000	-0.131	-0.118	-0.202	-0.202	-0.417
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.075	0.128	0.169	0.169	0.178
Cumulative Source Savings 2045 (Quads)		0.0000	0.025	0.044	0.057	0.057	0.060
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.021	0.170	0.138	0.138	-0.253
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.0091	-0.033	-0.033	-0.239

Table 10B.3.72 Equipment Class 4, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.582	0.582	0.577	0.565	0.555	0.526
Equipment Cost ($Billions)	9.56	-1.16	-1.16	-1.61	-2.77	-3.77	-7.26
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.15	3.15	3.58	5.06	5.09	5.34
Cumulative Source Savings 2045 (Quads)		1.07	1.07	1.21	1.71	1.72	1.80
Net Present Value at 3% Discount Rate ($Billions)		7.65	7.65	8.10	10.50	8.66	2.66
Net Present Value at 7% Discount Rate ($Billions)		1.99	1.99	1.96	2.28	1.32	-1.92

Table 10B.3.73 Equipment Class 5, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003
Equipment Cost ($Billions)	0.0047	0.0000	-0.0002	-0.0003	-0.0003	-0.0030
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0018
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0006
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0012	0.0012	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0013

Table 10B.3.74 Equipment Class 6, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.032	0.032	0.032	0.029
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.023	-0.023	-0.220
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.039	0.041	0.041	0.116
Cumulative Source Savings 2045 (Quads)		0.0071	0.014	0.015	0.015	0.042
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.079	0.082	0.082	-0.061
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.017	0.017	0.017	-0.103

Table 10B.3.75 Equipment Class 7, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0051
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0020	0.0020	0.0029
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0010
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0017	0.0026	0.0026	-0.0009
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	0.0001	0.0001	-0.0022

Table 10B.3.76 Equipment Class 8, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.172	0.170	0.165	0.165	0.154
Equipment Cost ($Billions)	1.95	-0.073	-0.184	-0.535	-0.535	-1.38
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.153	0.288	0.568	0.568	0.764
Cumulative Source Savings 2045 (Quads)		0.053	0.101	0.196	0.196	0.271
Net Present Value at 3% Discount Rate ($Billions)		0.339	0.547	0.745	0.745	-0.283
Net Present Value at 7% Discount Rate ($Billions)		0.080	0.104	0.033	0.033	-0.614

Table 10B.3.77 Equipment Class 9, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0004
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.3.78 Equipment Class 10, 1 Percent Load Growth, High Price Elasticity Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.021	-0.021	-0.021	-0.106
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0077	0.024	0.024	0.024	0.068
Cumulative Source Savings 2045 (Quads)		0.0029	0.0084	0.0084	0.0084	0.023
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.033	0.033	0.033	0.0054
Net Present Value at 7% Discount Rate ($Billions)		0.0045	0.0024	0.0024	0.0024	-0.039

10B.3.14 Medium Price Elasticity Scenario, Low Economic Growth Scenario

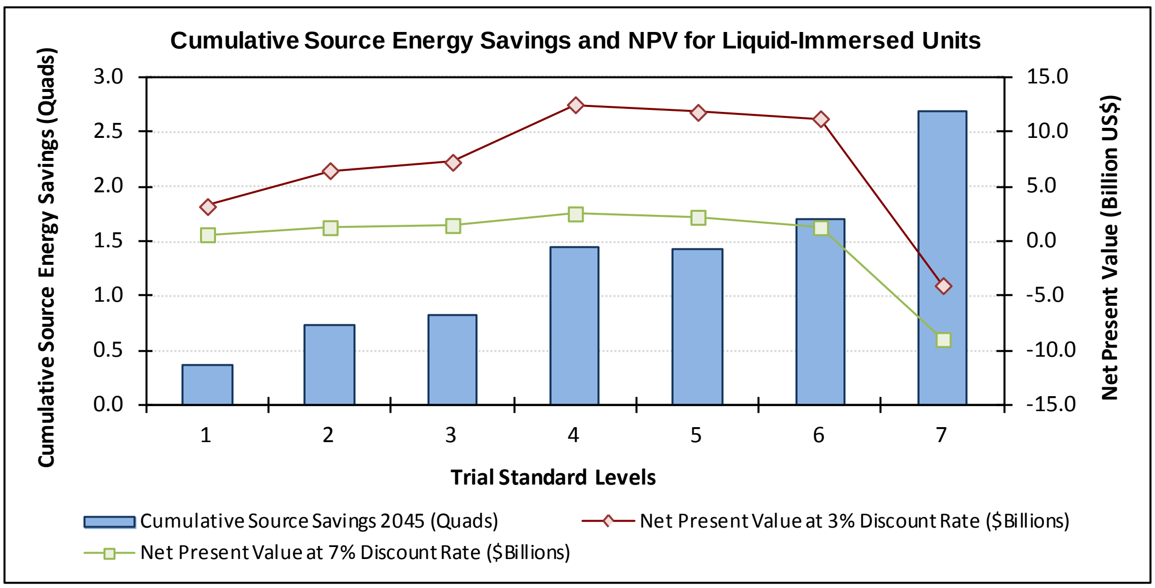

Figure 10B.3.10 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario

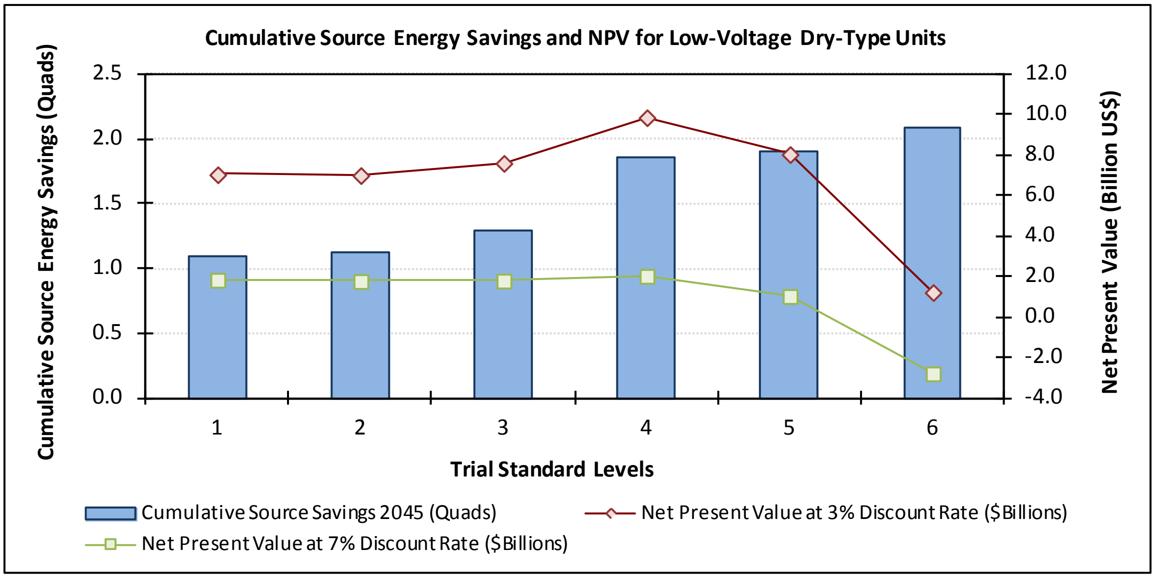

Figure 10B.3.11 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario

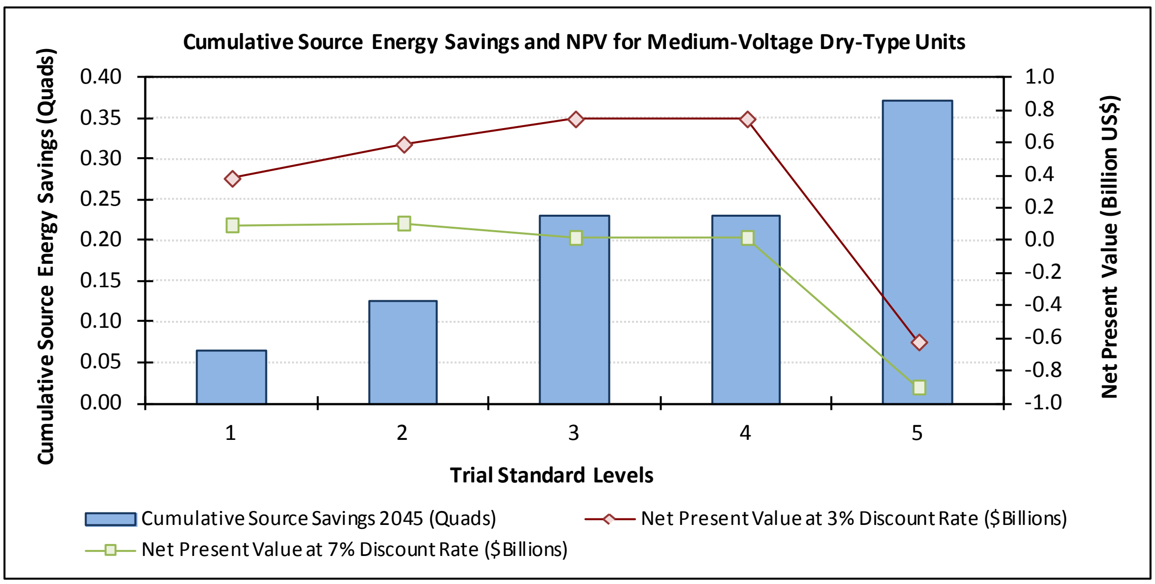

Figure 10B.3.12 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario

10B.3.14.2 3 Percent Discount Rate

Table 10B.3.79 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	63.05	-2.45	-4.91	-5.09	-8.32	-8.75	-12.34	-38.84
Operating Cost (Savings in TSLs) ($Billions)	69.83	5.67	11.41	12.35	20.85	20.58	23.59	34.81
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.21	6.50	7.26	12.53	11.83	11.25	-4.02
Net Present Value at 7% Discount Rate ($Billions)		0.634	1.28	1.48	2.54	2.23	1.28	-8.96

Table 10B.3.80 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	19.51	-2.30	-2.57	-3.48	-6.09	-8.23	-16.73
Operating Cost (Savings in TSLs) ($Billions)	24.55	9.36	9.58	11.09	15.95	16.28	17.96
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.01	7.61	9.87	8.05	1.23
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.78	1.80	2.04	1.04	-2.78

Table 10B.3.81 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.79	-0.154	-0.452	-1.18	-1.18	-3.69
Operating Cost (Savings in TSLs) ($Billions)	5.15	0.534	1.04	1.93	1.93	3.06
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.379	0.589	0.744	0.744	-0.626
Net Present Value at 7% Discount Rate ($Billions)		0.093	0.104	0.016	0.016	-0.903

Table 10B.3.82 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	43.68	-1.02	-3.48	-3.49	-5.10	-5.92	-7.90	-23.65
Operating Cost (Savings in TSLs) ($Billions)	34.08	1.06	6.80	6.87	10.87	11.29	12.40	17.54
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.039	3.32	3.38	5.77	5.36	4.49	-6.11
Net Present Value at 7% Discount Rate ($Billions)		-0.207	0.441	0.457	0.927	0.623	-0.065	-6.63

Table 10B.3.83 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.22	-2.83	-4.44	-15.19
Operating Cost (Savings in TSLs) ($Billions)	35.76	4.60	4.60	5.48	9.98	9.29	11.19	17.28
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.17	3.17	3.88	6.76	6.46	6.75	2.09
Net Present Value at 7% Discount Rate ($Billions)		0.841	0.841	1.02	1.61	1.61	1.34	-2.33

Table 10B.3.84 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.900	0.0000	-0.268	-0.241	-0.421	-0.421	-0.923
Operating Cost (Savings in TSLs) ($Billions)	0.791	0.0000	0.227	0.387	0.527	0.527	0.587
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.040	0.146	0.106	0.106	-0.336
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.064	0.0016	-0.046	-0.046	-0.284

Table 10B.3.85 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	18.61	-2.30	-2.30	-3.24	-5.67	-7.81	-15.81
Operating Cost (Savings in TSLs) ($Billions)	23.76	9.36	9.36	10.70	15.43	15.76	17.38
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.05	7.47	9.76	7.94	1.57
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.84	1.80	2.08	1.09	-2.50

Table 10B.3.86 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0065
Operating Cost (Savings in TSLs) ($Billions)	0.0099	0.0008	0.0014	0.0017	0.0017	0.0057
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0007	0.0009	0.0011	0.0011	-0.0008
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0015

Table 10B.3.87 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.475
Operating Cost (Savings in TSLs) ($Billions)	0.679	0.060	0.115	0.120	0.120	0.376
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.056	0.071	0.074	0.074	-0.099
Net Present Value at 7% Discount Rate ($Billions)		0.018	0.015	0.015	0.015	-0.122

Table 10B.3.88 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.015	0.0017	0.0027	0.0062	0.0062	0.0092
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0010	0.0015	0.0022	0.0022	-0.0017
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	-0.0001	-0.0001	-0.0026

Table 10B.3.89 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.09	-1.09	-2.98
Operating Cost (Savings in TSLs) ($Billions)	4.06	0.449	0.851	1.73	1.73	2.47
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.305	0.487	0.639	0.639	-0.514
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.088	-0.0003	-0.0003	-0.733

Table 10B.3.90 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0027	0.0002	0.0005	0.0005	0.0005	0.0014
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.3.91 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.387	0.023	0.070	0.070	0.070	0.201
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.016	0.028	0.028	0.028	-0.011
Net Present Value at 7% Discount Rate ($Billions)		0.0040	0.0010	0.0010	0.0010	-0.044

10B.3.14.3 7 Percent Discount Rate

Table 10B.3.92 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
Operating Cost (Savings in TSLs) ($Billions)	21.83	1.89	3.80	4.08	6.80	6.71	7.60	10.93
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.21	6.50	7.26	12.53	11.83	11.25	-4.02
Net Present Value at 7% Discount Rate ($Billions)		0.634	1.28	1.48	2.54	2.23	1.28	-8.96

Table 10B.3.93 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
Operating Cost (Savings in TSLs) ($Billions)	7.94	3.03	3.10	3.59	5.16	5.27	5.81
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.01	7.61	9.87	8.05	1.23
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.78	1.80	2.04	1.04	-2.78

Table 10B.3.94 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
Operating Cost (Savings in TSLs) ($Billions)	1.67	0.173	0.337	0.623	0.623	0.990
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.379	0.589	0.744	0.744	-0.626
Net Present Value at 7% Discount Rate ($Billions)		0.093	0.104	0.016	0.016	-0.903

Table 10B.3.95 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	22.36	-0.525	-1.78	-1.79	-2.61	-3.03	-4.05	-12.11
Operating Cost (Savings in TSLs) ($Billions)	10.68	0.317	2.22	2.24	3.54	3.66	3.98	5.48
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.039	3.32	3.38	5.77	5.36	4.49	-6.11
Net Present Value at 7% Discount Rate ($Billions)		-0.207	0.441	0.457	0.927	0.623	-0.065	-6.63

Table 10B.3.96 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.92	-0.732	-0.732	-0.818	-1.65	-1.45	-2.27	-7.78
Operating Cost (Savings in TSLs) ($Billions)	11.15	1.57	1.57	1.84	3.26	3.06	3.62	5.45
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.17	3.17	3.88	6.76	6.46	6.75	2.09
Net Present Value at 7% Discount Rate ($Billions)		0.841	0.841	1.02	1.61	1.61	1.34	-2.33

Table 10B.3.97 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.462	0.0000	-0.137	-0.124	-0.216	-0.216	-0.474
Operating Cost (Savings in TSLs) ($Billions)	0.256	0.0000	0.074	0.125	0.170	0.170	0.190
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.040	0.146	0.106	0.106	-0.336
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.064	0.0016	-0.046	-0.046	-0.284

Table 10B.3.98 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.56	-1.18	-1.18	-1.66	-2.91	-4.01	-8.12
Operating Cost (Savings in TSLs) ($Billions)	7.68	3.03	3.03	3.46	4.99	5.10	5.62
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.05	7.05	7.47	9.76	7.94	1.57
Net Present Value at 7% Discount Rate ($Billions)		1.84	1.84	1.80	2.08	1.09	-2.50

Table 10B.3.99 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0033
Operating Cost (Savings in TSLs) ($Billions)	0.0032	0.0003	0.0004	0.0005	0.0005	0.0018
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0007	0.0009	0.0011	0.0011	-0.0008
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0015

Table 10B.3.100 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.244
Operating Cost (Savings in TSLs) ($Billions)	0.220	0.019	0.037	0.039	0.039	0.122
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.056	0.071	0.074	0.074	-0.099
Net Present Value at 7% Discount Rate ($Billions)		0.018	0.015	0.015	0.015	-0.122

Table 10B.3.101 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0056
Operating Cost (Savings in TSLs) ($Billions)	0.0048	0.0005	0.0009	0.0020	0.0020	0.0030
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0010	0.0015	0.0022	0.0022	-0.0017
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0003	-0.0001	-0.0001	-0.0026

Table 10B.3.102 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.560	-0.560	-1.53
Operating Cost (Savings in TSLs) ($Billions)	1.31	0.145	0.275	0.559	0.559	0.798
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.305	0.487	0.639	0.639	-0.514
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.088	-0.0003	-0.0003	-0.733

Table 10B.3.103 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0004
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0003

Table 10B.3.104 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.125	0.0073	0.023	0.023	0.023	0.065
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.016	0.028	0.028	0.028	-0.011
Net Present Value at 7% Discount Rate ($Billions)		0.0040	0.0010	0.0010	0.0010	-0.044

10B.3.15 Medium Price Elasticity Scenario, High Economic Growth Scenario

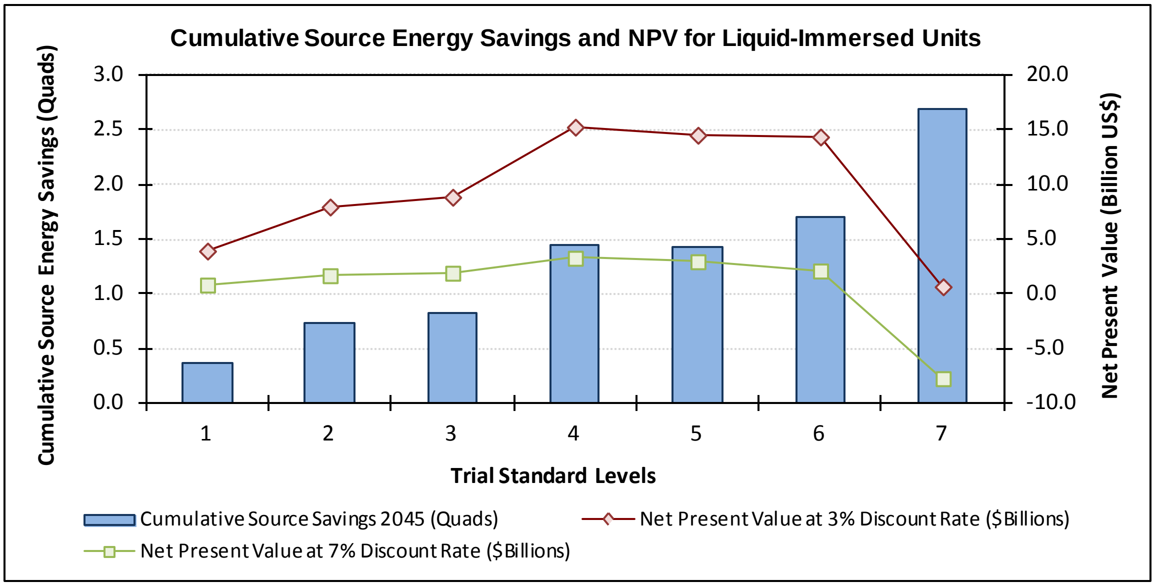

Figure 10B.3.13 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario

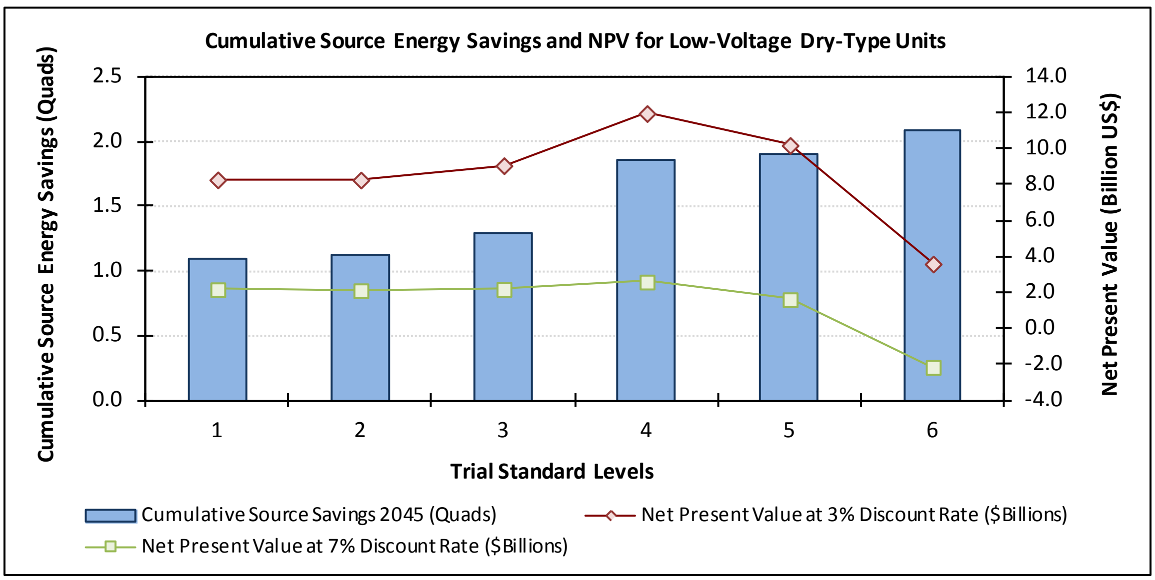

Figure 10B.3.14 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario

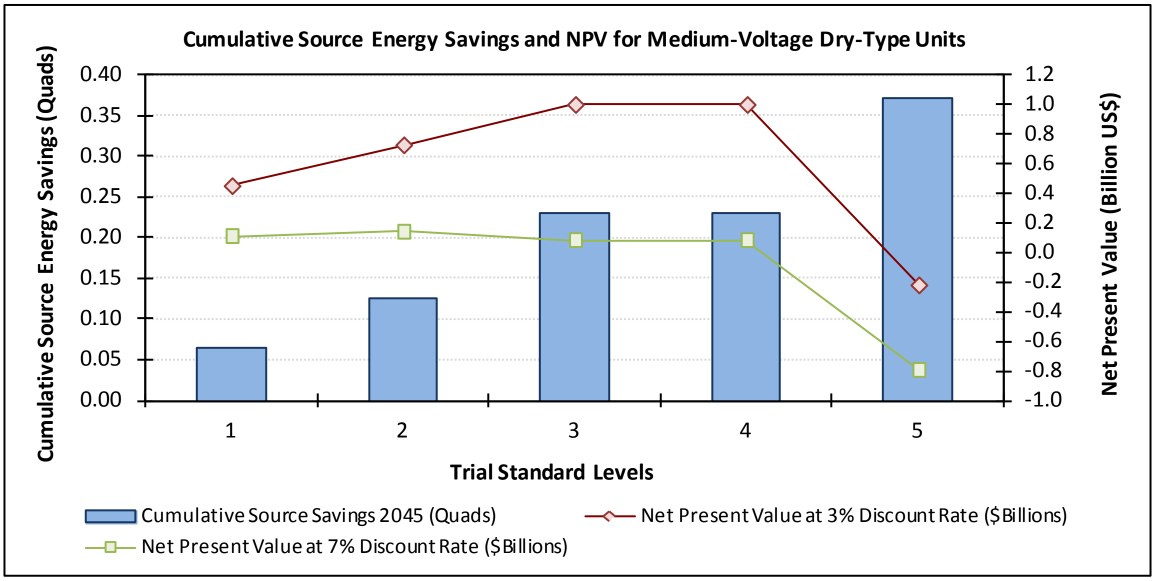

Figure 10B.3.15 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario

10B.3.15.2 3 Percent Discount Rate

Table 10B.3.105 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	63.05	-2.45	-4.91	-5.09	-8.32	-8.75	-12.34	-38.84
Operating Cost (Savings in TSLs) ($Billions)	79.30	6.40	12.88	13.96	23.59	23.29	26.72	39.52
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.95	7.97	8.87	15.27	14.54	14.38	0.682
Net Present Value at 7% Discount Rate ($Billions)		0.839	1.70	1.92	3.29	2.97	2.12	-7.72

Table 10B.3.106 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	19.51	-2.30	-2.57	-3.48	-6.09	-8.23	-16.73
Operating Cost (Savings in TSLs) ($Billions)	27.79	10.59	10.85	12.56	18.07	18.44	20.34
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.28	9.08	11.98	10.20	3.61
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.12	2.20	2.61	1.62	-2.14

Table 10B.3.107 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.79	-0.154	-0.452	-1.18	-1.18	-3.69
Operating Cost (Savings in TSLs) ($Billions)	5.83	0.604	1.18	2.18	2.18	3.47
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.450	0.726	0.999	0.999	-0.221
Net Present Value at 7% Discount Rate ($Billions)		0.113	0.142	0.085	0.085	-0.793

Table 10B.3.108 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	43.68	-1.02	-3.48	-3.49	-5.10	-5.92	-7.90	-23.65
Operating Cost (Savings in TSLs) ($Billions)	38.69	1.21	7.70	7.77	12.30	12.78	14.05	19.91
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.187	4.22	4.28	7.20	6.86	6.14	-3.73
Net Present Value at 7% Discount Rate ($Billions)		-0.170	0.686	0.704	1.32	1.03	0.379	-6.00

Table 10B.3.109 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	19.37	-1.43	-1.43	-1.60	-3.22	-2.83	-4.44	-15.19
Operating Cost (Savings in TSLs) ($Billions)	40.61	5.19	5.19	6.19	11.29	10.51	12.67	19.61
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.76	3.76	4.59	8.08	7.68	8.23	4.42
Net Present Value at 7% Discount Rate ($Billions)		1.01	1.01	1.22	1.97	1.94	1.75	-1.72

Table 10B.3.110 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.900	0.0000	-0.268	-0.241	-0.421	-0.421	-0.923
Operating Cost (Savings in TSLs) ($Billions)	0.895	0.0000	0.257	0.438	0.596	0.596	0.665
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.010	0.198	0.175	0.175	-0.258
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.056	0.016	-0.027	-0.027	-0.263

Table 10B.3.111 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	18.61	-2.30	-2.30	-3.24	-5.67	-7.81	-15.81
Operating Cost (Savings in TSLs) ($Billions)	26.90	10.59	10.59	12.12	17.47	17.84	19.68
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.29	8.88	11.80	10.03	3.87
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.18	2.18	2.64	1.65	-1.87

Table 10B.3.112 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0091	-0.0001	-0.0005	-0.0006	-0.0006	-0.0065
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0016	0.0019	0.0019	0.0064
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0009	0.0011	0.0013	0.0013	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0002	0.0003	0.0003	-0.0013

Table 10B.3.113 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.604	-0.0035	-0.044	-0.046	-0.046	-0.475
Operating Cost (Savings in TSLs) ($Billions)	0.768	0.068	0.131	0.136	0.136	0.426
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.064	0.086	0.090	0.090	-0.049
Net Present Value at 7% Discount Rate ($Billions)		0.020	0.019	0.019	0.019	-0.109

Table 10B.3.114 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.015	-0.0007	-0.0012	-0.0040	-0.0040	-0.011
Operating Cost (Savings in TSLs) ($Billions)	0.017	0.0019	0.0031	0.0070	0.0070	0.010
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0013	0.0019	0.0030	0.0030	-0.0005
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0004	0.0002	0.0002	-0.0023

Table 10B.3.115 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.80	-0.144	-0.364	-1.09	-1.09	-2.98
Operating Cost (Savings in TSLs) ($Billions)	4.59	0.508	0.963	1.96	1.96	2.79
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.364	0.600	0.868	0.868	-0.188
Net Present Value at 7% Discount Rate ($Billions)		0.087	0.119	0.062	0.062	-0.644

Table 10B.3.116 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0025	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0030	0.0002	0.0005	0.0005	0.0005	0.0016
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0003	0.0003	0.0003	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.3.117 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.360	-0.0063	-0.042	-0.042	-0.042	-0.212
Operating Cost (Savings in TSLs) ($Billions)	0.439	0.026	0.079	0.079	0.079	0.227
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.019	0.037	0.037	0.037	0.016
Net Present Value at 7% Discount Rate ($Billions)		0.0049	0.0035	0.0035	0.0035	-0.036

10B.3.15.3 7 Percent Discount Rate

Table 10B.3.118 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
Operating Cost (Savings in TSLs) ($Billions)	24.31	2.10	4.21	4.53	7.55	7.45	8.44	12.17
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.95	7.97	8.87	15.27	14.54	14.38	0.682
Net Present Value at 7% Discount Rate ($Billions)		0.839	1.70	1.92	3.29	2.97	2.12	-7.72

Table 10B.3.119 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
Operating Cost (Savings in TSLs) ($Billions)	8.82	3.36	3.44	3.99	5.73	5.85	6.46
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.28	9.08	11.98	10.20	3.61
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.12	2.20	2.61	1.62	-2.14

Table 10B.3.120 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
Operating Cost (Savings in TSLs) ($Billions)	1.85	0.192	0.374	0.693	0.693	1.10
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.450	0.726	0.999	0.999	-0.221
Net Present Value at 7% Discount Rate ($Billions)		0.113	0.142	0.085	0.085	-0.793

Table 10B.3.121 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	22.36	-0.525	-1.78	-1.79	-2.61	-3.03	-4.05	-12.11
Operating Cost (Savings in TSLs) ($Billions)	11.89	0.354	2.47	2.49	3.93	4.06	4.43	6.11
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.187	4.22	4.28	7.20	6.86	6.14	-3.73
Net Present Value at 7% Discount Rate ($Billions)		-0.170	0.686	0.704	1.32	1.03	0.379	-6.00

Table 10B.3.122 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.92	-0.732	-0.732	-0.818	-1.65	-1.45	-2.27	-7.78
Operating Cost (Savings in TSLs) ($Billions)	12.42	1.74	1.74	2.04	3.62	3.39	4.02	6.06
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.76	3.76	4.59	8.08	7.68	8.23	4.42
Net Present Value at 7% Discount Rate ($Billions)		1.01	1.01	1.22	1.97	1.94	1.75	-1.72

Table 10B.3.123 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.462	0.0000	-0.137	-0.124	-0.216	-0.216	-0.474
Operating Cost (Savings in TSLs) ($Billions)	0.284	0.0000	0.082	0.139	0.189	0.189	0.211
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.010	0.198	0.175	0.175	-0.258
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.056	0.016	-0.027	-0.027	-0.263

Table 10B.3.124 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.56	-1.18	-1.18	-1.66	-2.91	-4.01	-8.12
Operating Cost (Savings in TSLs) ($Billions)	8.54	3.36	3.36	3.85	5.54	5.66	6.25
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		8.29	8.29	8.88	11.80	10.03	3.87
Net Present Value at 7% Discount Rate ($Billions)		2.18	2.18	2.18	2.64	1.65	-1.87

Table 10B.3.125 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0047	0.0000	-0.0003	-0.0003	-0.0003	-0.0033
Operating Cost (Savings in TSLs) ($Billions)	0.0035	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0009	0.0011	0.0013	0.0013	-0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0002	0.0003	0.0003	-0.0013

Table 10B.3.126 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.310	-0.0018	-0.023	-0.024	-0.024	-0.244
Operating Cost (Savings in TSLs) ($Billions)	0.244	0.021	0.042	0.043	0.043	0.135
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.064	0.086	0.090	0.090	-0.049
Net Present Value at 7% Discount Rate ($Billions)		0.020	0.019	0.019	0.019	-0.109

Table 10B.3.127 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0078	-0.0003	-0.0006	-0.0020	-0.0020	-0.0056
Operating Cost (Savings in TSLs) ($Billions)	0.0054	0.0006	0.0010	0.0022	0.0022	0.0033
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0013	0.0019	0.0030	0.0030	-0.0005
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0004	0.0002	0.0002	-0.0023

Table 10B.3.128 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.95	-0.074	-0.187	-0.560	-0.560	-1.53
Operating Cost (Savings in TSLs) ($Billions)	1.46	0.161	0.306	0.621	0.621	0.887
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.364	0.600	0.868	0.868	-0.188
Net Present Value at 7% Discount Rate ($Billions)		0.087	0.119	0.062	0.062	-0.644

Table 10B.3.129 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0013	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0010	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0003	0.0003	0.0003	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.3.130 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Economic Growth Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.185	-0.0032	-0.022	-0.022	-0.022	-0.109
Operating Cost (Savings in TSLs) ($Billions)	0.139	0.0081	0.025	0.025	0.025	0.072
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.019	0.037	0.037	0.037	0.016
Net Present Value at 7% Discount Rate ($Billions)		0.0049	0.0035	0.0035	0.0035	-0.036

10B.3.16 Low Price Trend Scenario

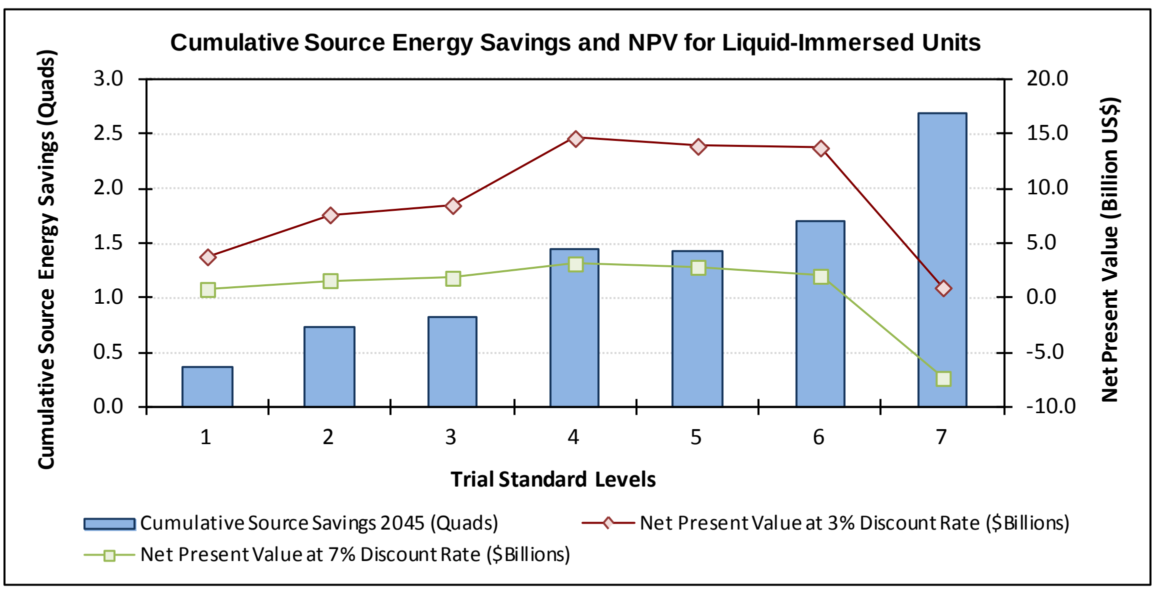

Figure 10B.3.16 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario

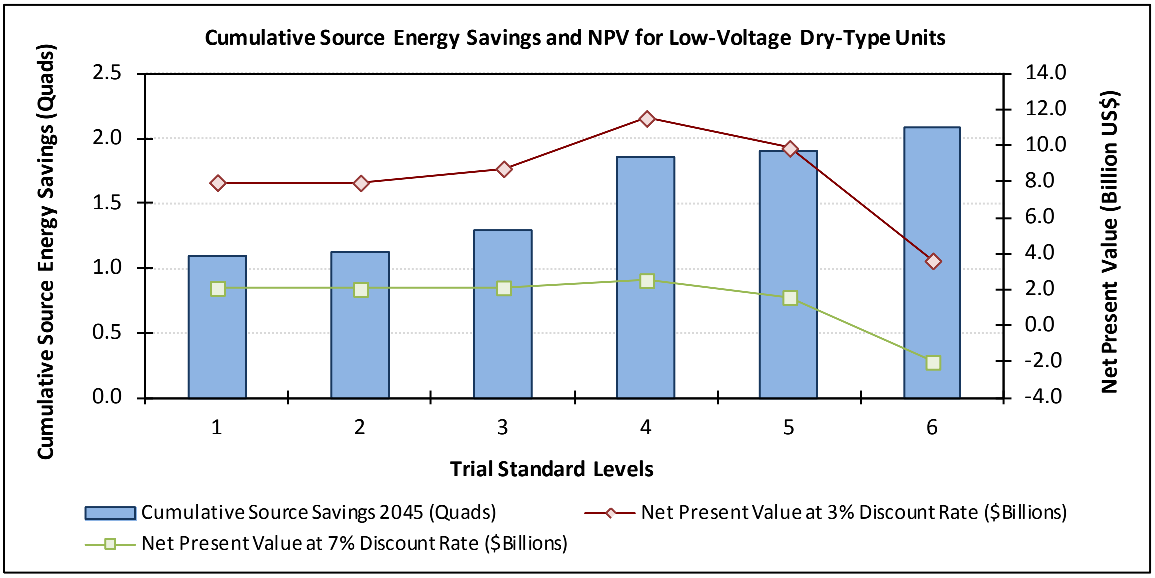

Figure 10B.3.17 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario

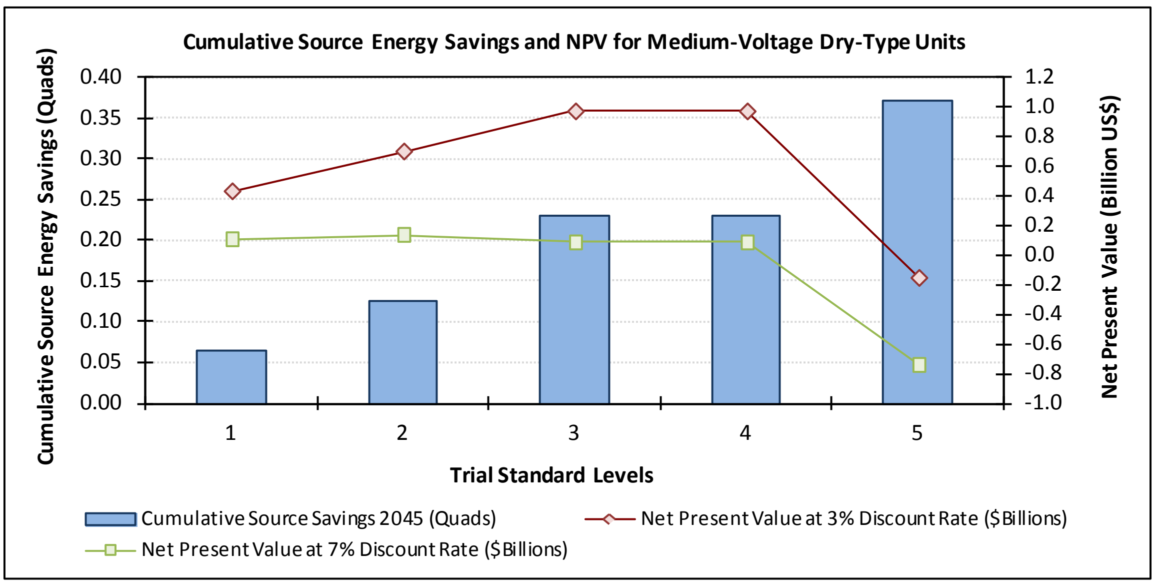

Figure 10B.3.18 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario

10B.3.16.2 3 Percent Discount Rate

Table 10B.3.131 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	60.90	-2.32	-4.67	-4.84	-7.91	-8.33	-11.76	-36.77
Operating Cost (Savings in TSLs) ($Billions)	75.69	6.11	12.30	13.33	22.53	22.24	25.51	37.72
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.79	7.63	8.49	14.62	13.91	13.75	0.955
Net Present Value at 7% Discount Rate ($Billions)		0.809	1.62	1.84	3.15	2.84	2.02	-7.33

Table 10B.3.132 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	18.72	-2.14	-2.40	-3.24	-5.70	-7.72	-15.79
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.11	10.36	11.99	17.25	17.61	19.42
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.96	8.75	11.55	9.88	3.63
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.05	2.13	2.53	1.60	-2.00

Table 10B.3.133 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	4.52	-0.144	-0.423	-1.11	-1.11	-3.46
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.08	2.08	3.31
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.433	0.702	0.973	0.973	-0.153
Net Present Value at 7% Discount Rate ($Billions)		0.109	0.139	0.087	0.087	-0.741

Table 10B.3.134 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	42.38	-0.978	-3.33	-3.34	-4.88	-5.67	-7.58	-22.51
Operating Cost (Savings in TSLs) ($Billions)	36.93	1.16	7.35	7.42	11.74	12.20	13.41	19.01
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.179	4.02	4.08	6.86	6.53	5.83	-3.50
Net Present Value at 7% Discount Rate ($Billions)		-0.165	0.645	0.663	1.25	0.965	0.330	-5.76

Table 10B.3.135 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	18.52	-1.34	-1.34	-1.50	-3.03	-2.66	-4.18	-14.26
Operating Cost (Savings in TSLs) ($Billions)	38.76	4.96	4.96	5.91	10.78	10.03	12.10	18.72
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.61	3.61	4.41	7.76	7.37	7.92	4.45
Net Present Value at 7% Discount Rate ($Billions)		0.974	0.974	1.17	1.90	1.87	1.69	-1.57

Table 10B.3.136 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.868	0.0000	-0.262	-0.227	-0.400	-0.400	-0.878
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.246	0.419	0.569	0.569	0.635
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.016	0.191	0.170	0.170	-0.243
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.015	-0.026	-0.026	-0.252

Table 10B.3.137 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	17.85	-2.14	-2.14	-3.01	-5.30	-7.32	-14.91
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.11	10.11	11.57	16.68	17.04	18.79
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.98	8.56	11.38	9.71	3.88
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.11	2.12	2.56	1.62	-1.74

Table 10B.3.138 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0086	-0.0001	-0.0005	-0.0006	-0.0006	-0.0061
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0013	0.0013	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0012

Table 10B.3.139 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.570	-0.0033	-0.042	-0.043	-0.043	-0.446
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.407
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.083	0.086	0.086	-0.039
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.018	0.019	0.019	-0.102

Table 10B.3.140 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.014	-0.0006	-0.0011	-0.0037	-0.0037	-0.010
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0067	0.0067	0.0099
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0018	0.0029	0.0029	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0003	0.0002	0.0002	-0.0021

Table 10B.3.141 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	3.58	-0.134	-0.340	-1.02	-1.02	-2.80
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.920	1.87	1.87	2.67
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.351	0.580	0.846	0.846	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.085	0.116	0.065	0.065	-0.602

Table 10B.3.142 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0023	0.0000	-0.0003	-0.0003	-0.0003	-0.0014
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.3.143 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.339	-0.0060	-0.039	-0.039	-0.039	-0.198
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.217
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.036	0.036	0.036	0.019
Net Present Value at 7% Discount Rate ($Billions)		0.0047	0.0036	0.0036	0.0036	-0.034

10B.3.16.3 7 Percent Discount Rate

Table 10B.3.144 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	31.33	-1.20	-2.41	-2.50	-4.08	-4.29	-6.06	-18.97
Operating Cost (Savings in TSLs) ($Billions)	23.26	2.01	4.03	4.33	7.22	7.13	8.08	11.64
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.79	7.63	8.49	14.62	13.91	13.75	0.955
Net Present Value at 7% Discount Rate ($Billions)		0.809	1.62	1.84	3.15	2.84	2.02	-7.33

Table 10B.3.145 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	9.67	-1.11	-1.24	-1.68	-2.95	-4.00	-8.17
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.81	5.49	5.60	6.18
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.96	8.75	11.55	9.88	3.63
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.05	2.13	2.53	1.60	-2.00

Table 10B.3.146 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.34	-0.075	-0.219	-0.575	-0.575	-1.79
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.358	0.663	0.663	1.05
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.433	0.702	0.973	0.973	-0.153
Net Present Value at 7% Discount Rate ($Billions)		0.109	0.139	0.087	0.087	-0.741

Table 10B.3.147 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	21.79	-0.504	-1.72	-1.72	-2.51	-2.92	-3.90	-11.60
Operating Cost (Savings in TSLs) ($Billions)	11.37	0.339	2.36	2.38	3.76	3.89	4.23	5.84
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.179	4.02	4.08	6.86	6.53	5.83	-3.50
Net Present Value at 7% Discount Rate ($Billions)		-0.165	0.645	0.663	1.25	0.965	0.330	-5.76

Table 10B.3.148 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	9.54	-0.693	-0.693	-0.775	-1.56	-1.37	-2.16	-7.37
Operating Cost (Savings in TSLs) ($Billions)	11.88	1.67	1.67	1.95	3.46	3.25	3.84	5.80
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.61	3.61	4.41	7.76	7.37	7.92	4.45
Net Present Value at 7% Discount Rate ($Billions)		0.974	0.974	1.17	1.90	1.87	1.69	-1.57

Table 10B.3.149 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.448	0.0000	-0.135	-0.118	-0.207	-0.207	-0.454
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.078	0.133	0.181	0.181	0.202
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.016	0.191	0.170	0.170	-0.243
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.057	0.015	-0.026	-0.026	-0.252

Table 10B.3.150 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	9.22	-1.11	-1.11	-1.56	-2.75	-3.79	-7.72
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.68	5.31	5.42	5.98
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.98	7.98	8.56	11.38	9.71	3.88
Net Present Value at 7% Discount Rate ($Billions)		2.11	2.11	2.12	2.56	1.62	-1.74

Table 10B.3.151 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0044	0.0000	-0.0002	-0.0003	-0.0003	-0.0032
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0010	0.0013	0.0013	0.0000
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0003	0.0003	-0.0012

Table 10B.3.152 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.295	-0.0017	-0.022	-0.022	-0.022	-0.231
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.129
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.083	0.086	0.086	-0.039
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.018	0.019	0.019	-0.102

Table 10B.3.153 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0074	-0.0003	-0.0006	-0.0019	-0.0019	-0.0053
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0012	0.0018	0.0029	0.0029	-0.0003
Net Present Value at 7% Discount Rate ($Billions)		0.0003	0.0003	0.0002	0.0002	-0.0021

Table 10B.3.154 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	1.85	-0.070	-0.176	-0.530	-0.530	-1.45
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.595	0.595	0.848
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.351	0.580	0.846	0.846	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.085	0.116	0.065	0.065	-0.602

Table 10B.3.155 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0012	0.0000	-0.0001	-0.0001	-0.0001	-0.0007
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	0.0001
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0002

Table 10B.3.156 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, Low Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.176	-0.0031	-0.020	-0.020	-0.020	-0.103
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.018	0.036	0.036	0.036	0.019
Net Present Value at 7% Discount Rate ($Billions)		0.0047	0.0036	0.0036	0.0036	-0.034

10B.3.17 High Price Trend Scenario

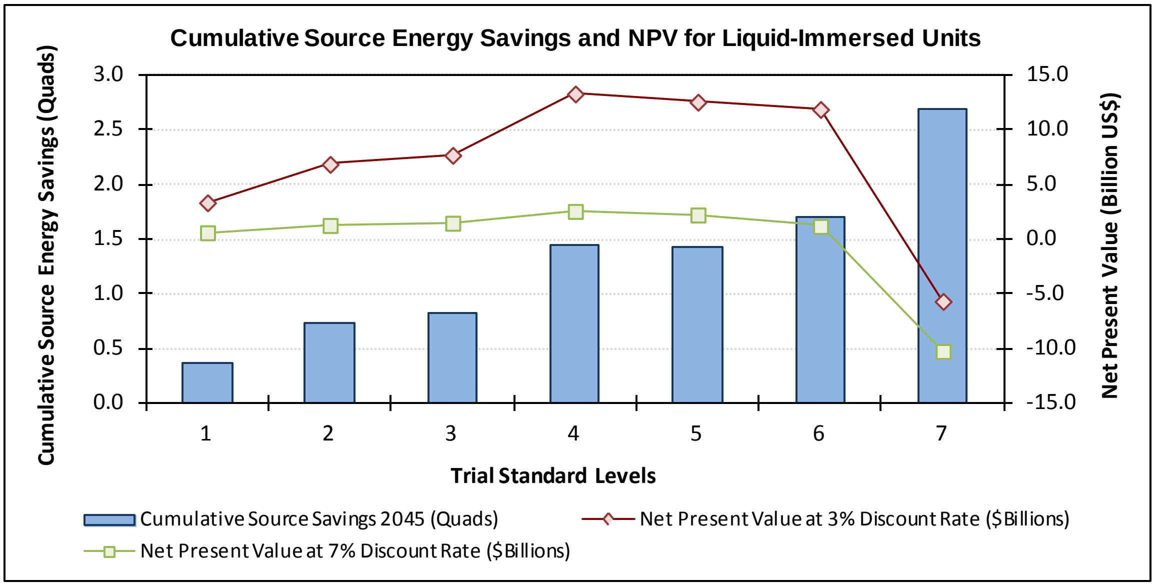

Figure 10B.3.19 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario

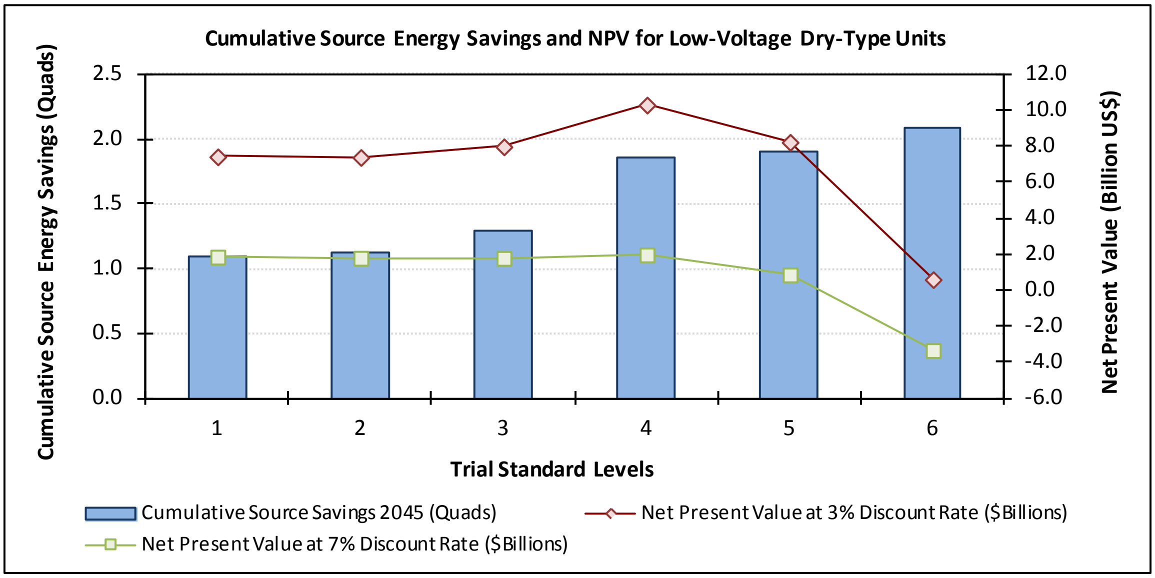

Figure 10B.3.20 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario

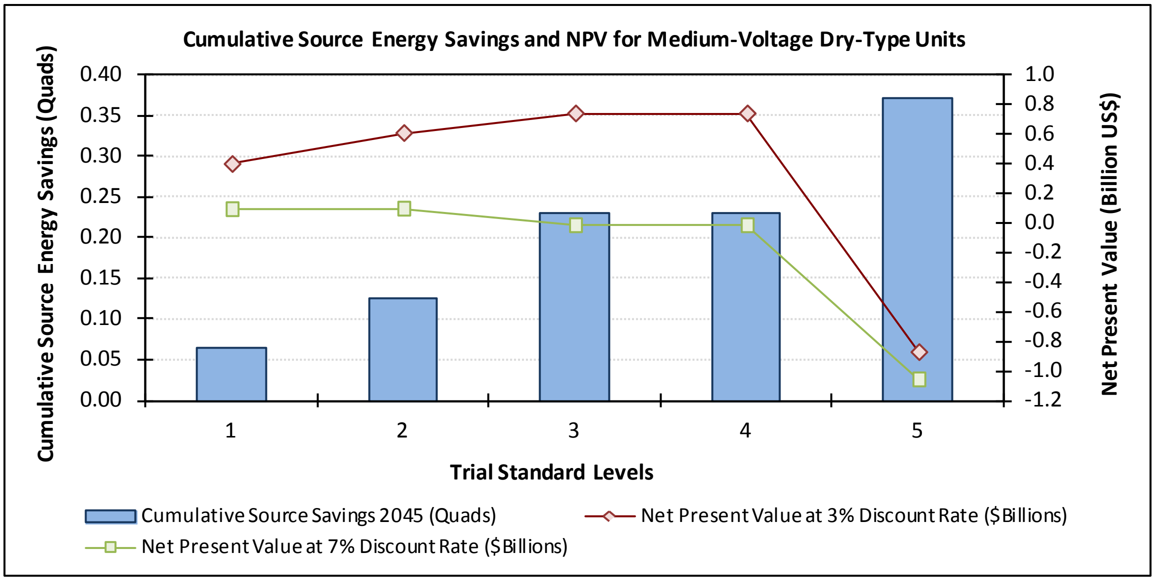

Figure 10B.3.21 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario

10B.3.17.2 3 Percent Discount Rate

Table 10B.3.157 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	67.78	-2.75	-5.43	-5.63	-9.22	-9.68	-13.62	-43.38
Operating Cost (Savings in TSLs) ($Billions)	75.69	6.11	12.30	13.33	22.53	22.24	25.51	37.72
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.36	6.87	7.70	13.31	12.56	11.89	-5.66
Net Present Value at 7% Discount Rate ($Billions)		0.620	1.29	1.49	2.57	2.25	1.20	-10.23

Table 10B.3.158 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	21.24	-2.68	-2.96	-3.99	-6.93	-9.36	-18.80
Operating Cost (Savings in TSLs) ($Billions)	26.54	10.11	10.36	11.99	17.25	17.61	19.42
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.40	7.99	10.31	8.25	0.618
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.81	1.80	1.99	0.879	-3.32

Table 10B.3.159 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	5.40	-0.177	-0.516	-1.34	-1.34	-4.18
Operating Cost (Savings in TSLs) ($Billions)	5.57	0.577	1.13	2.08	2.08	3.31
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.400	0.609	0.742	0.742	-0.873
Net Present Value at 7% Discount Rate ($Billions)		0.094	0.098	-0.014	-0.014	-1.06

Table 10B.3.160 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	46.54	-1.13	-3.81	-3.82	-5.58	-6.48	-8.61	-26.16
Operating Cost (Savings in TSLs) ($Billions)	36.93	1.16	7.35	7.42	11.74	12.20	13.41	19.01
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.029	3.54	3.60	6.16	5.72	4.80	-7.15
Net Present Value at 7% Discount Rate ($Billions)		-0.231	0.437	0.454	0.938	0.610	-0.120	-7.36

Table 10B.3.161 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	21.24	-1.62	-1.62	-1.81	-3.63	-3.20	-5.01	-17.22
Operating Cost (Savings in TSLs) ($Billions)	38.76	4.96	4.96	5.91	10.78	10.03	12.10	18.72
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.33	3.33	4.10	7.15	6.84	7.09	1.49
Net Present Value at 7% Discount Rate ($Billions)		0.851	0.851	1.04	1.63	1.64	1.32	-2.87

Table 10B.3.162 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.972	0.0000	-0.280	-0.270	-0.468	-0.468	-1.02
Operating Cost (Savings in TSLs) ($Billions)	0.855	0.0000	0.246	0.419	0.569	0.569	0.635
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.035	0.148	0.101	0.101	-0.387
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.065	-0.0034	-0.056	-0.056	-0.315

Table 10B.3.163 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	20.27	-2.68	-2.68	-3.72	-6.47	-8.89	-17.78
Operating Cost (Savings in TSLs) ($Billions)	25.68	10.11	10.11	11.57	16.68	17.04	18.79
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.44	7.85	10.21	8.14	1.01
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.87	1.81	2.05	0.935	-3.01

Table 10B.3.164 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.010	-0.0001	-0.0006	-0.0007	-0.0007	-0.0074
Operating Cost (Savings in TSLs) ($Billions)	0.011	0.0009	0.0015	0.0018	0.0018	0.0062
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0009	0.0011	0.0011	-0.0012
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0018

Table 10B.3.165 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.678	-0.0040	-0.050	-0.052	-0.052	-0.538
Operating Cost (Savings in TSLs) ($Billions)	0.734	0.065	0.125	0.130	0.130	0.407
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.075	0.078	0.078	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.014	0.015	0.015	-0.142

Table 10B.3.166 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.017	-0.0008	-0.0014	-0.0045	-0.0045	-0.012
Operating Cost (Savings in TSLs) ($Billions)	0.016	0.0018	0.0029	0.0067	0.0067	0.0099
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0011	0.0016	0.0021	0.0021	-0.0024
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	-0.0002	-0.0002	-0.0031

Table 10B.3.167 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	4.28	-0.165	-0.415	-1.24	-1.24	-3.38
Operating Cost (Savings in TSLs) ($Billions)	4.38	0.485	0.920	1.87	1.87	2.67
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.320	0.504	0.633	0.633	-0.714
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.083	-0.029	-0.029	-0.857

Table 10B.3.168 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0028	0.0000	-0.0003	-0.0003	-0.0003	-0.0016
Operating Cost (Savings in TSLs) ($Billions)	0.0029	0.0002	0.0005	0.0005	0.0005	0.0015
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0002
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0004

Table 10B.3.169 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 3 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.406	-0.0071	-0.048	-0.048	-0.048	-0.241
Operating Cost (Savings in TSLs) ($Billions)	0.419	0.024	0.076	0.076	0.076	0.217
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.017	0.028	0.028	0.028	-0.024
Net Present Value at 7% Discount Rate ($Billions)		0.0042	-0.0001	-0.0001	-0.0001	-0.052

10B.3.17.3 7 Percent Discount Rate

Table 10B.3.170 Liquid-Immersed Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.95	1.95	1.95	1.95	1.94	1.94	1.94	1.91
Equipment Cost ($Billions)	34.34	-1.39	-2.74	-2.84	-4.65	-4.88	-6.88	-21.87
Operating Cost (Savings in TSLs) ($Billions)	23.26	2.01	4.03	4.33	7.22	7.13	8.08	11.64
Cumulative Source Savings 2045 (Quads)		0.363	0.736	0.816	1.44	1.42	1.70	2.70
Net Present Value at 3% Discount Rate ($Billions)		3.36	6.87	7.70	13.31	12.56	11.89	-5.66
Net Present Value at 7% Discount Rate ($Billions)		0.620	1.29	1.49	2.57	2.25	1.20	-10.23

Table 10B.3.171 LVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.617	0.616	0.616	0.615	0.614	0.613	0.610
Equipment Cost ($Billions)	10.78	-1.35	-1.49	-2.01	-3.50	-4.72	-9.50
Operating Cost (Savings in TSLs) ($Billions)	8.44	3.22	3.30	3.81	5.49	5.60	6.18
Cumulative Source Savings 2045 (Quads)		1.09	1.12	1.29	1.86	1.90	2.08
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.40	7.99	10.31	8.25	0.618
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.81	1.80	1.99	0.879	-3.32

Table 10B.3.172 MVDT Transformers, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.223	0.223	0.223	0.222	0.222	0.221
Equipment Cost ($Billions)	2.72	-0.089	-0.260	-0.677	-0.677	-2.11
Operating Cost (Savings in TSLs) ($Billions)	1.77	0.184	0.358	0.663	0.663	1.05
Cumulative Source Savings 2045 (Quads)		0.064	0.126	0.229	0.229	0.373
Net Present Value at 3% Discount Rate ($Billions)		0.400	0.609	0.742	0.742	-0.873
Net Present Value at 7% Discount Rate ($Billions)		0.094	0.098	-0.014	-0.014	-1.06

Table 10B.3.173 Equipment Class 1, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	0.801	0.800	0.798	0.798	0.797	0.796	0.795	0.786
Equipment Cost ($Billions)	23.61	-0.570	-1.92	-1.93	-2.82	-3.28	-4.36	-13.20
Operating Cost (Savings in TSLs) ($Billions)	11.37	0.339	2.36	2.38	3.76	3.89	4.23	5.84
Cumulative Source Savings 2045 (Quads)		0.093	0.466	0.471	0.754	0.796	0.896	1.37
Net Present Value at 3% Discount Rate ($Billions)		0.029	3.54	3.60	6.16	5.72	4.80	-7.15
Net Present Value at 7% Discount Rate ($Billions)		-0.231	0.437	0.454	0.938	0.610	-0.120	-7.36

Table 10B.3.174 Equipment Class 2, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level							
	Base	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Transformer Shipments 2015-2045 (Billion KVA)	1.15	1.15	1.15	1.15	1.15	1.15	1.14	1.13
Equipment Cost ($Billions)	10.73	-0.816	-0.816	-0.912	-1.83	-1.61	-2.52	-8.66
Operating Cost (Savings in TSLs) ($Billions)	11.88	1.67	1.67	1.95	3.46	3.25	3.84	5.80
Cumulative Source Savings 2045 (Quads)		0.269	0.269	0.345	0.689	0.626	0.799	1.33
Net Present Value at 3% Discount Rate ($Billions)		3.33	3.33	4.10	7.15	6.84	7.09	1.49
Net Present Value at 7% Discount Rate ($Billions)		0.851	0.851	1.04	1.63	1.64	1.32	-2.87

Table 10B.3.175 Equipment Class 3, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.022	0.022	0.021	0.021	0.021	0.021	0.021
Equipment Cost ($Billions)	0.494	0.0000	-0.143	-0.137	-0.237	-0.237	-0.517
Operating Cost (Savings in TSLs) ($Billions)	0.272	0.0000	0.078	0.133	0.181	0.181	0.202
Cumulative Source Savings 2045 (Quads)		0.0000	0.026	0.046	0.061	0.061	0.068
Net Present Value at 3% Discount Rate ($Billions)		0.0000	-0.035	0.148	0.101	0.101	-0.387
Net Present Value at 7% Discount Rate ($Billions)		0.0000	-0.065	-0.0034	-0.056	-0.056	-0.315

Table 10B.3.176 Equipment Class 4, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level						
	Base	**1**	**2**	**3**	**4**	**5**	**6**
Transformer Shipments 2015-2045 (Billion KVA)	0.596	0.594	0.594	0.594	0.593	0.592	0.588
Equipment Cost ($Billions)	10.28	-1.35	-1.35	-1.88	-3.26	-4.48	-8.98
Operating Cost (Savings in TSLs) ($Billions)	8.17	3.22	3.22	3.68	5.31	5.42	5.98
Cumulative Source Savings 2045 (Quads)		1.09	1.09	1.25	1.80	1.83	2.01
Net Present Value at 3% Discount Rate ($Billions)		7.44	7.44	7.85	10.21	8.14	1.01
Net Present Value at 7% Discount Rate ($Billions)		1.87	1.87	1.81	2.05	0.935	-3.01

Table 10B.3.177 Equipment Class 5, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
Equipment Cost ($Billions)	0.0051	0.0000	-0.0003	-0.0003	-0.0003	-0.0037
Operating Cost (Savings in TSLs) ($Billions)	0.0034	0.0003	0.0005	0.0006	0.0006	0.0020
Cumulative Source Savings 2045 (Quads)		0.0001	0.0002	0.0002	0.0002	0.0007
Net Present Value at 3% Discount Rate ($Billions)		0.0008	0.0009	0.0011	0.0011	-0.0012
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	0.0002	0.0002	-0.0018

Table 10B.3.178 Equipment Class 6, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.033	0.033	0.033	0.033	0.033	0.033
Equipment Cost ($Billions)	0.343	-0.0020	-0.025	-0.026	-0.026	-0.272
Operating Cost (Savings in TSLs) ($Billions)	0.233	0.021	0.040	0.041	0.041	0.129
Cumulative Source Savings 2045 (Quads)		0.0071	0.015	0.015	0.015	0.047
Net Present Value at 3% Discount Rate ($Billions)		0.061	0.075	0.078	0.078	-0.132
Net Present Value at 7% Discount Rate ($Billions)		0.019	0.014	0.015	0.015	-0.142

Table 10B.3.179 Equipment Class 7, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Equipment Cost ($Billions)	0.0086	-0.0004	-0.0007	-0.0023	-0.0023	-0.0062
Operating Cost (Savings in TSLs) ($Billions)	0.0051	0.0006	0.0009	0.0021	0.0021	0.0032
Cumulative Source Savings 2045 (Quads)		0.0002	0.0003	0.0007	0.0007	0.0011
Net Present Value at 3% Discount Rate ($Billions)		0.0011	0.0016	0.0021	0.0021	-0.0024
Net Present Value at 7% Discount Rate ($Billions)		0.0002	0.0002	-0.0002	-0.0002	-0.0031

Table 10B.3.180 Equipment Class 8, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.173	0.173	0.173	0.172	0.172	0.171
Equipment Cost ($Billions)	2.16	-0.083	-0.209	-0.624	-0.624	-1.71
Operating Cost (Savings in TSLs) ($Billions)	1.39	0.154	0.293	0.595	0.595	0.848
Cumulative Source Savings 2045 (Quads)		0.053	0.103	0.205	0.205	0.301
Net Present Value at 3% Discount Rate ($Billions)		0.320	0.504	0.633	0.633	-0.714
Net Present Value at 7% Discount Rate ($Billions)		0.071	0.083	-0.029	-0.029	-0.857

Table 10B.3.181 Equipment Class 9, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Equipment Cost ($Billions)	0.0014	0.0000	-0.0002	-0.0002	-0.0002	-0.0008
Operating Cost (Savings in TSLs) ($Billions)	0.0009	0.0001	0.0002	0.0002	0.0002	0.0005
Cumulative Source Savings 2045 (Quads)		0.0000	0.0001	0.0001	0.0001	0.0002
Net Present Value at 3% Discount Rate ($Billions)		0.0001	0.0002	0.0002	0.0002	-0.0002
Net Present Value at 7% Discount Rate ($Billions)		0.0000	0.0000	0.0000	0.0000	-0.0004

Table 10B.3.182 Equipment Class 10, 1 Percent Load Growth, Medium Price Elasticity Scenario, High Price Trend Scenario, 7 Percent Discount Rate

	Trial Standard Level					
	Base	**1**	**2**	**3**	**4**	**5**
Transformer Shipments 2015-2045 (Billion KVA)	0.016	0.016	0.016	0.016	0.016	0.016
Equipment Cost ($Billions)	0.205	-0.0036	-0.024	-0.024	-0.024	-0.121
Operating Cost (Savings in TSLs) ($Billions)	0.133	0.0078	0.024	0.024	0.024	0.069
Cumulative Source Savings 2045 (Quads)		0.0030	0.0085	0.0085	0.0085	0.024
Net Present Value at 3% Discount Rate ($Billions)		0.017	0.028	0.028	0.028	-0.024
Net Present Value at 7% Discount Rate ($Billions)		0.0042	-0.0001	-0.0001	-0.0001	-0.052

APPENDIX 10C. NIA SENSITIVITY ANALYSIS FOR ALTERNATIVE PRODUCT PRICE TREND SCENARIOS

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APPENDIX 10C. NIA SENSITIVITY ANALYSIS FOR ALTERNATIVE PRODUCT PRICE TREND SCENARIOS

10C.1 INTRODUCTION

DOE used a constant price assumption for the default forecast in the NIA described in Chapter 10. In order to investigate the impact of different product price forecasts on the consumer net present value (NPV) for the considered TSLs for distribution transformers, DOE also considered two alternative price trends for a sensitivity analysis. This appendix describes the alternative price trends and compares NPV results for these scenarios with the default forecast.

10C.2 ALTERNATIVE TRANSFORMER TREND SCENARIOS

DOE used an exponential fit on the deflated Producer Price Index (PPI) for power, distribution, and specialty transformer manufacturing. Based these data for electric power and specialty transformer manufacturing, DOE developed one forecast in which prices decline after 2010, and one in which prices rise.. For these scenarios, DOE used an inflation-adjusted power, distribution, and specialty transformer manufacturing PPI from 1967-2010 to fit an exponential model with *year* as the explanatory variable. DOE obtained historical PPI data for power, distribution, and specialty transformer manufacturing spanning the time period 1967-2010 from the Bureau of Labor Statistics' (BLS).[a] The PPI data reflect nominal prices, adjusted for product quality changes. An inflation-adjusted (deflated) price index for power, distribution, and specialty transformer manufacturing was calculated by dividing the PPI series by the Gross Domestic Product Chained Price Index. In this case, the exponential function takes the form of:

$$Y = a \times e^{bX}$$

where Y is the distribution transformer price index, X is the time variable, a is the constant and b is the slope parameter of the time variable.

To estimate these exponential parameters, a least-square fit was performed on the inflation-adjusted distribution transformer price index versus *year* from 1967 to 2010. See Figure 10-B.2.1.

[a] Series ID PCU335311335311; http://www.bls.gov/ppi/

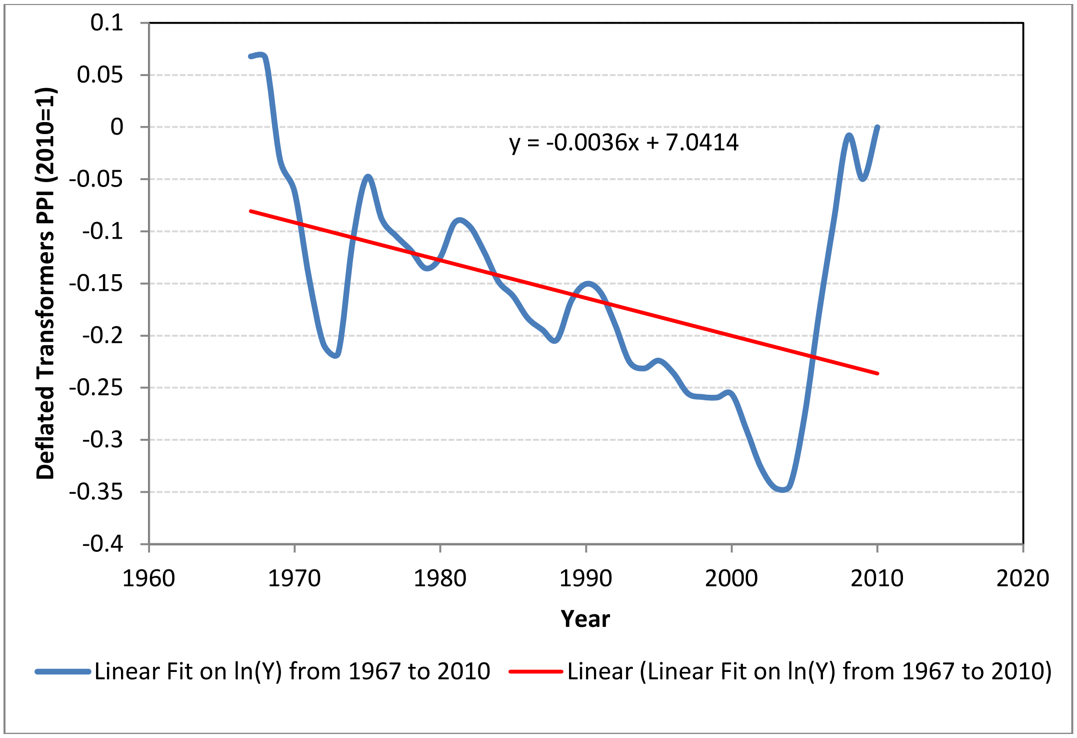

Figure 10C.2.1 Low Price Scenario (1967-2010): Relative Price of Distribution Transformers versus Year, with Exponential Fit

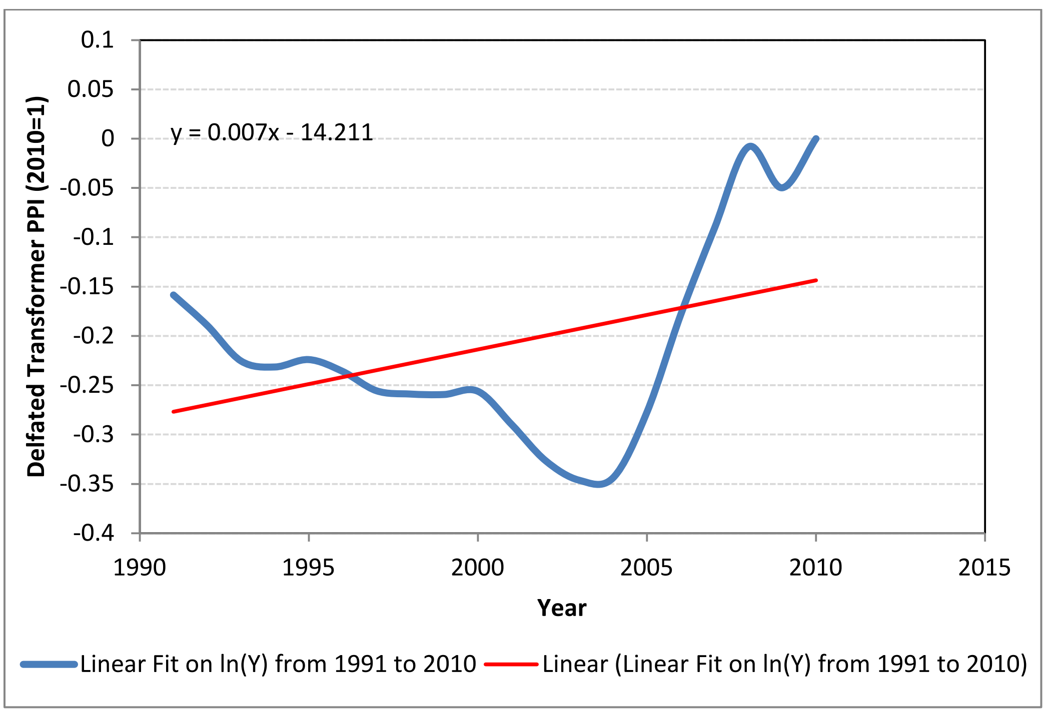

Figure 10C.2.2 High Price Scenario (1991-2010): Relative Price of Distribution Transformers versus Year, with Exponential Fit

The final estimated exponential function is:

$$Y = 2.45 \times 10^{(-6)} \cdot e^{0.0064X}$$

DOE then derived a price factor index for this scenario, with 2010 equal to 1, to forecast 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.2.1 Summary

Table 10-B.2.1 shows the summary of the average annual rates of changes for the product price index in each scenario. Figure 10-B.2.2 shows the resulting price trends.

Table 10C.2.1 Price Trend Sensitivities

Sensitivity	Price Trend	Average Annual rate of change
Medium (Default)	Constant Price Projection	0.00%
Low Price Scenario	Exponential Fit using data from 1967 to 2010	-0.36%
High Price Scenario	Exponential Fit using data from 1991 to 2010	0.70%

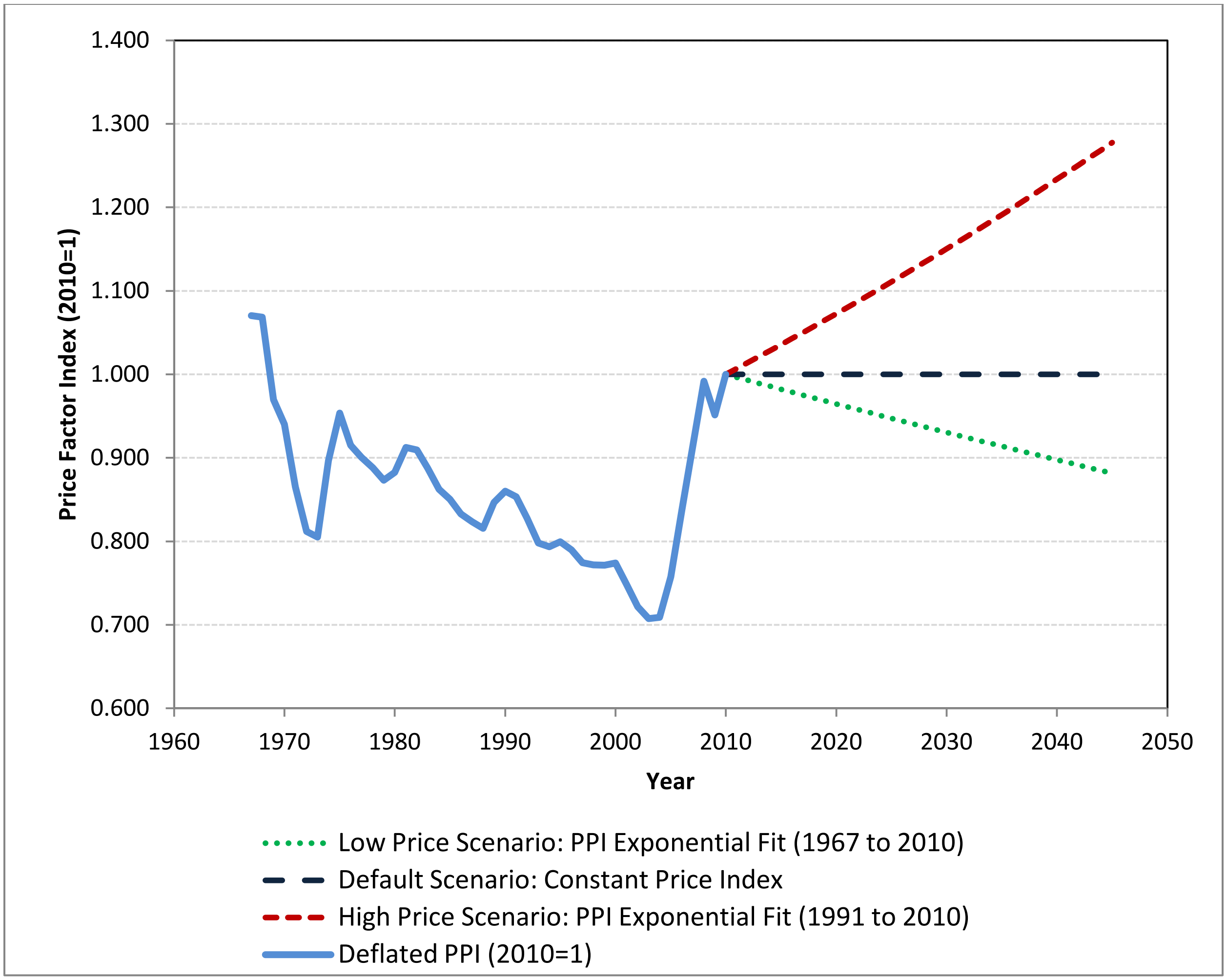

Figure 10C.2.3 Distribution Transformer Price Forecast Indexes

10C.3 NPV RESULTS BY PRICE TREND SCENARIO

Table 10-B.3.1 through Table 10-B.3.3 present, for each product class grouping and TSL, equipment incremental non-energy costs and energy cost savings, with their corresponding NPV results, across discount rates and the three product price trend scenarios.

Table 10C.3.1 Detailed NPV Results for Liquid Immersed Distribution Transformers (billion 2010$)

		Trial Standard Level							
		Base	1	2	3	4	5	6	7
Low Price Trend	Equipment Costs	31.33	-1.20	-2.41	-2.50	-4.08	-4.29	-6.06	-18.97
	Operating Cost Savings	23.26	2.01	4.03	4.33	7.22	7.13	8.08	11.64
	NPV @ 3% Discount Rate		3.79	7.63	8.49	14.62	13.91	13.75	0.95
	NPV @ 7% Discount Rate		0.809	1.62	1.84	3.15	2.84	2.02	-7.33
Default Price Trend	Equipment Costs	32.28	-1.26	-2.51	-2.61	-4.26	-4.48	-6.32	-19.88
	Operating Cost Savings	23.26	2.01	4.03	4.33	7.22	7.13	8.08	11.64
	NPV @ 3% Discount Rate		3.66	7.39	8.24	14.21	13.48	13.17	-1.11
	NPV @ 7% Discount Rate		0.749	1.51	1.73	2.96	2.65	1.76	-8.25
High Price Trend	Equipment Costs	34.34	-1.39	-2.74	-2.84	-4.65	-4.88	-6.88	-21.87
	Operating Cost Savings	23.26	2.01	4.03	4.33	7.22	7.13	8.08	11.64
	NPV @ 3% Discount Rate		2.58	4.52	7.09	10.27	-4.38		
	NPV @ 7% Discount Rate		-0.64	-0.55	0.37	1.02	-9.35		

Table 10C.3.2 Detailed NPV Results for Low Voltage Dry-Type Distribution Transformers (billion 2010$)

		Trial Standard Level						
		Base	1	2	3	4	5	6
Low Price Trend	Equipment Costs	9.67	-1.11	-1.24	-1.68	-2.95	-4.00	-8.17
	Operating Cost Savings	8.44	3.22	3.30	3.81	5.49	5.60	6.18
	NPV @ 3% Discount Rate		7.98	7.96	8.75	11.55	9.88	3.634
	NPV @ 7% Discount Rate		2.11	2.05	2.13	2.53	1.599	-2.00
Default Price Trend	Equipment Costs	10.02	-1.18	-1.32	-1.79	-3.13	-4.23	-8.59
	Operating Cost Savings	8.44	3.22	3.30	3.81	5.49	5.60	6.18
	NPV @ 3% Discount Rate		7.81	7.79	8.51	11.16	9.37	2.690
	NPV @ 7% Discount Rate		2.03	1.97	2.03	2.36	1.372	-2.41
High Price Trend	Equipment Costs	10.78	-1.35	-1.49	-2.01	-3.50	-4.72	-9.50
	Operating Cost Savings	8.44	3.22	3.30	3.81	5.49	5.60	6.18
	NPV @ 3% Discount Rate		7.44	7.40	7.99	10.31	8.25	0.618
	NPV @ 7% Discount Rate		1.87	1.81	1.80	1.99	0.879	-3.32

Table 10C.3.3 Detailed NPV Results for Medium Voltage Dry-Type Distribution Transformers (billion 2010$)

		Trial Standard Level					
		Base	1	2	3	4	5
Low Price Trend	Equipment Costs	2.34	-0.075	-0.219	-0.575	-0.575	-1.79
	Operating Cost Savings	1.77	0.184	0.358	0.663	0.663	1.05
	NPV @ 3% Discount Rate		0.433	0.702	0.973	0.973	-0.153
	NPV @ 7% Discount Rate		0.109	0.139	0.087	0.087	-0.74
Default Price Trend	Equipment Costs	2.46	-0.079	-0.232	-0.607	-0.607	-1.89
	Operating Cost Savings	1.77	0.184	0.358	0.663	0.663	1.05
	NPV @ 3% Discount Rate		0.423	0.673	0.901	0.901	-0.378
	NPV @ 7% Discount Rate		0.104	0.126	0.055	0.055	-0.84
High Price Trend	Equipment Costs	2.72	-0.089	-0.260	-0.677	-0.677	-2.11
	Operating Cost Savings	1.77	0.184	0.358	0.663	0.663	1.05
	NPV @ 3% Discount Rate		0.400	0.609	0.742	0.742	-0.873
	NPV @ 7% Discount Rate		0.094	0.098	-0.014	-0.014	-1.06

Manufacturer Impact Analysis Interview Guide for Distribution Transformers

May 20, 2011

Introduction

As part of the rulemaking process for amended energy conservation standards for distribution transformers, 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 DOE about how changes in the energy conservation standard will affect distribution transformer manufacturers. All information provided in response to this questionnaire will be treated as confidential. In addition to questions about DOE's test procedure, scope of coverage, market assessment, and engineering analysis, the MIA questions range from requests about specific financial figures for use in industry modeling to generic questions intended to solicit qualitative comments. Topics covered will include:

A. Test Procedure
B. Scope of Coverage
C. Market and Technology Assessment
D. Engineering Analysis
E. Market Questionnaire
F. Manufacturer Impact Analysis
    1. Key Issues
    2. Company Overview And Organizational Characteristics
    3. Markups And Profitability
    4. Distribution Channels
    5. Shipment Projections and Market Shares
    6. Financial Parameters
    7. Conversion Costs
    8. Cumulative Regulatory Burden
    9. Direct Employment Impact Assessment
    10. Capacity/Exports / Foreign Competition / Outsourcing
    11. Consolidation
    12. Impacts on Small Business

A. TEST PROCEDURE

DOE published its test procedure for distribution transformers in 2006. Since then, manufacturers and other stakeholders have raised issues on several points in the test procedure.

The test procedure states that the manufacturer must determine the basic model's efficiency either at the voltage at which the highest losses occur or at each voltage at which the transformer is rated to operate. This provision was implemented to address dual- or multiple-voltage transformers, which have different losses for each of their winding configurations (in series or in parallel). In the preliminary analysis, DOE proposed allowing compliance testing with the secondary winding in any configuration, but did not propose any changes for the requirements of primary windings. DOE understands that the different primary winding configurations oftentimes exhibit larger differences in efficiency than the efficiency differences between secondary windings configurations.

A.1 **Dual/Multiple-Voltage Winding Configurations – Primary Voltages:** How does the efficiency vary between series and parallel configurations for transformers with dual/multiple-voltage primaries? What proportion of distribution transformers are operated with the primary winding in parallel and for what portion of their lives?

A.2 **Other Issues with the Test Procedure:** Are there any other issues or concerns with the current test procedure that DOE should be aware of?

B. SCOPE OF COVERAGE

DOE received several comments about the scope of coverage for this rulemaking. The following questions seek additional information on a few scope related topics.

B.1 **5 kVA Single-Phase Liquid-Immersed Transformers:** Should DOE extend its scope of coverage for single-phase liquid-immersed transformers down to 5 kVA? The current minimum is 10 kVA. Approximately how many annual shipments are there for these transformers? Is the design for 5 kVA units similar to the design for 10 kVA units?

B.2 **Step-Up Transformers:** Should step-up transformers of comparable kVA sizes to DOE's currently covered products be included in the scope of this rulemaking? Do these step-up transformers use similar design constructions as step-down covered products? Can they meet similar efficiency levels? Would they require comparable cost increases to improve efficiency? Can they be scaled from the analysis for step-down transformers?

B.3 **Transformers in Renewable Energy Applications:** Are distribution transformers that are used in renewable energy applications different in any way from distribution transformers used in other applications? Are these transformers typically loaded comparably to distribution transformers in other applications?

C. MARKET AND TECHNOLOGY ASSESSMENT

Symmetric Core Designs: DOE is aware of a design concept for three-phase transformers that utilizes 120˚ symmetry and continuously wound cores. These symmetric core designs, such as the Hexaformer® design created by Hexaformer AB, have several benefits over a traditional transformer design, including: lower losses, lower inrush current, lower weight, and lower external magnetic field. Chalmers University in Sweden has conducted a study on symmetric core designs and provided an overview of the design and insights into modeling the technology.[1] DOE understands that symmetric core designs represent a significant shift from current industry practice for manufacturing distribution transformers.

C.1 **Symmetric Core Designs - Applications:** Please comment on any experience your company has with symmetric core designs. Would any barriers exist to implementing this type of technology on a large scale? DOE understands that symmetric core designs cannot be used in a wye-wye connection unless a tertiary winding is added. What applications would not be suitable for symmetric core designs?

C.2 **Symmetric Core Designs – Performance and Costs:** How do labor costs for symmetric core designs compare to traditional designs? What intellectual property exists for this technology, and what are the typical licensing costs of using patented symmetric core designs? Please provide any data you have available on the performance and cost of these designs compared to conventional core designs, particularly for the representative units of DOE's analysis.

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1 Available online: http://www.hexaformer.com/ExternaDokument/chalmers_report1.pdf.

D. ENGINEERING ANALYSIS

The purpose of the engineering analysis is to estimate the relationship between the manufacturer's selling price of a transformer and its corresponding efficiency rating. This relationship serves as the basis for the subsequent cost-benefit calculations for individual consumers, manufacturers, and the nation.

The engineering analysis considers design lines of distribution transformers that group together kVA ratings based on similar principles of design and construction. The design lines differentiate the distribution transformers by insulation type (liquid-immersed or dry-type), number of phases (single or three), the primary voltage (low-voltage or medium-voltage for dry-types) and primary insulation levels (with three different BILs for medium-voltage dry-types).

Within each design line, DOE selects one representative unit for study in the engineering analysis. DOE then extrapolates the results from these representative units to the other kVA ratings in its engineering design line. The design lines and representative units currently selected for this engineering analysis are similar to the ones presented in the preliminary analysis with a few changes and additions.

1 LIQUID-IMMERSED ENGINEERING ANALYSIS

Design Lines and Representative Units

The following table represents the five design lines and representative units DOE is considering for liquid-immersed distribution transformers, which have not changed from the preliminary analysis. While DOE did not change the voltages for these representative units, it will conduct a sensitivity analysis to examine alternate primary voltage levels.

Design Lines and Representative Units for Liquid-Immersed Distribution Transformers

Design Line	# of Phases	KVA Range	Primary BIL	Primary Taps, Full Capacity	Representative Unit for Design Lines
1	1	10-167	30-150 kV	Four 2.5% taps, two above and two below nominal	50kVA, 65˚C, single-phase, 60Hz, 14400V primary, 240/120V secondary, 125 kV BIL, rectangular tank
2	1	10-167	30-150 kV	Four 2.5% taps, two above and two below nominal	25kVA, 65˚C, single-phase, 60Hz, 14400V primary, 120/240V secondary, 125 kV BIL, round tank
3	1	250-833	30-150 kV	Four 2.5% taps, two above and two below nominal	500kVA, 65˚C, single-phase, 60Hz, 14400V primary, 277V secondary, 150 kV BIL
4	3	15-500	30-150 kV	Four 2.5% taps, two above and two below nominal	150kVA, 65˚C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary, 95 kV BIL
5	3	750-2500	95-150 kV	Four 2.5% taps, two above and two below nominal	1500kVA, 65˚C, three-phase, 60Hz, 24940GrdY/14400V primary, 408Y/277V secondary, 125 kV BIL

D.1.1 **Liquid-Immersed Design Lines:** Please comment on the appropriateness of the design lines and representative units chosen for the liquid-immersed distribution transformers. Should any other representative units be selected, and why? Would these other representative units experience different incremental costs for increasing efficiency as compared to the current rep units?

D.1.2 **Dimension and Weight Constraints:** For each of the representative units, are there any weight constraints or dimensional constraints for customer applications that DOE should be aware of? If so, please specify the maximum weight and/or dimensions that are feasible.

Design Option Combinations

For each representative unit, DOE is considering several design option combinations that characterize a range of efficiency levels for distribution transformers. This range spans from the efficiency level requirements set forth in DOE's 2007 final rule to the maximum technologically available level ("max tech"). Within this range, DOE considers several discrete candidate standard levels (CSLs) for setting the efficiency standard. The following tables present the CSL efficiency level and request feedback on the design options available to reach that efficiency level, the manufacturer's production cost (MPC) of the lowest first-cost design at that level, and the manufacturer's selling price (MSP) for that design. The MPC consists of all direct and indirect production costs, and the MSP includes the MPC plus non-production costs (e.g., SG&A, R&D, profit factor, etc.).

Design Line 1
(50kVA, 65° C, single-phase, 60 Hz, 14400V primary, 240/120V secondary, 125 kV BIL, rectangular tank)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
Example: 99.27		≥M3 (conventional core); ≥M5 (symmetric core); Al and Cu.	1,840	2,300
0	99.08			
1	99.17			
2	99.27			
3	99.36			
4	99.46			
5	99.55			
6	99.60			

Design Line 2
(25kVA, 65˚ C, single-phase, 60 Hz, 14400V primary, 120/240V secondary, 125 kV BIL, round tank)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	98.91			
1	99.02			
2	99.13			
3	99.24			
4	99.35			
5	99.46			

Design Line 3
(500kVA, 65˚C, single-phase, 60Hz, 14400V primary, 277V secondary, 150 kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	99.42			
1	99.48			
2	99.54			
3	99.57			
4	99.61			
5	99.67			
6	99.73			
7	99.76			

Design Line 4
(150kVA, 65˚ C, three-phase, 60 Hz, 12470Y/7200V primary, 208Y/120V secondary, 95kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	99.08			
1	99.17			
2	99.27			
3	99.36			
4	99.46			
5	99.55			
6	99.60			

Design Line 5
(1500kVA, 65˚ C, three-phase, 60 Hz, 24940GrdY/14400V primary, 480Y/277V secondary, 125 kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	99.42			
1	99.48			
2	99.54			
3	99.57			
4	99.61			
5	99.67			
6	99.73			

D.1.3 **Amorphous Cores in Large kVA Designs:** DOE understands that amorphous cores in large distribution transformers (1500 kVA and greater) require additional labor and hardware costs above and beyond the requirements for other core steels in these designs. The labor accounts for extra handling required for these large, fragile designs, and the hardware costs account for additional bracing to prevent short circuit problems. Please comment on how these costs compare between amorphous designs and other designs using the table below.

Direct Labor and Bracing Costs for Design Line 5
(1500kVA, 65˚ C, three-phase, 60 Hz, 24940GrdY/14400V primary, 408Y/277V secondary, 125 kV BIL)

Core Steel	**Direct Labor for Typical Design [*hours*]**	**Bracing Costs for Typical Design [*$*]**	**Comments**
M4			
M3			
M2			
ZDMH			
SA1 (Amorphous)			

2 LOW-VOLTAGE DRY-TYPE ENGINEERING ANALYSIS

Design Lines and Representative Units

The following table represents the three design lines and representative units DOE is considering for low-voltage dry-type distribution transformers, which have not changed from the preliminary analysis.

Design Lines and Representative Units for Low-Voltage Dry-Type Distribution Transformers

Design Line	# of Phases	KVA Range	Primary BIL	Primary Taps, Full Capacity	Representative Unit for Design Lines
6	1	15-333	10 kV	Universal*	25kVA, 150˚C, single-phase, 60Hz, 480V primary, 120Y/240V secondary, 10kV BIL
7	3	15-150	10 kV	Universal*	75kVA, 150˚C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL
8	3	225-1000	10 kV	Universal*	300kVA, 150˚C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL

* Universal Taps = 2 above and 4 below 2.5%

D.2.1 **Low-Voltage Dry-Type Design Lines:** Please comment on the appropriateness of the design lines and representative units chosen for the low-voltage dry-type distribution transformers. Should any other representative units be selected, and why? Would these other representative units experience different incremental costs for increasing efficiency as compared to the current rep units?

D.2.2 **Dimension and Weight Constraints:** For each of the representative units, are there any weight constraints or dimensional constraints for customer applications that DOE should be aware of? If so, please specify the maximum weight and/or dimensions that are feasible.

Design Option Combinations

For each representative unit, DOE is considering several design option combinations that characterize a range of efficiency levels for distribution transformers. This range spans from the efficiency level requirements set forth in the Energy Policy Act of 2005 to the maximum technologically available level ("max tech"). Within this range, DOE considers several discrete candidate standard levels (CSLs) for setting the efficiency standard. The following tables present the CSL efficiency level and request feedback on the design options available to reach that efficiency level, the manufacturer's production cost (MPC) of the lowest first-cost design at that level, and the manufacturer's selling price (MSP) for that design. The MPC consists of all direct and indirect production costs, and the MSP includes the MPC plus non-production costs (e.g., SG&A, R&D, profit factor, etc.).

Design Line 6
(25kVA, 150˚ C, single-phase, 60 Hz, 480V primary, 120/240V secondary, 10 kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
Example: 98.23		≥M6 (conventional core); ≥M12 (symmetric core); butt-lap or miter	1,600	2,000
0	98.00			
1	98.23			
2	98.47			
3	98.60			
4	98.70			
5	98.93			
6	99.17			
7	99.40			

Design Line 7
(75kVA, 150˚C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	98.00			
1	98.23			
2	98.47			
3	98.60			
4	98.70			
5	98.93			
6	99.17			
7	99.40			

Design Line 8
(300kVA, 150˚C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	98.60			
1	98.80			
2	99.02			
3	99.19			
4	99.41			
5	99.59			

3 MEDIUM-VOLTAGE DRY-TYPE ENGINEERING ANALYSIS

Design Lines and Representative Units

The following table represents the six design lines and representative units DOE is considering for medium-voltage dry-type distribution transformers. DOE is considering an additional sixth design line for lower kVA ratings in the highest insulation class. To do this, DOE split its existing design line 13 into two design lines, 13A and 13B, where 13A considers kVA ratings between 15 and 500, and 13B considers kVA ratings between 750 and 2500. The representative unit from 13B is similar to the one examined during the preliminary analysis, but DOE changed its primary voltage. The remaining design lines 9 through 12 have not changed.

Design Lines and Representative Units for Medium-Voltage Dry-Type Distribution Transformers

Design Line	# of Phases	KVA Range	Primary BIL	Primary Taps, Full Capacity	Representative Unit for Design Lines
9	3	15-500	20-45 kV	Four 2.5% taps, two above and two below nominal	300kVA, 150˚C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL
10	3	750-2500	20-45 kV	Four 2.5% taps, two above and two below nominal	1500kVA, 150˚C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
11	3	15-500	46-95 kV	Four 2.5% taps, two above and two below nominal	300kVA, 150˚C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
12	3	750-2500	46-95 kV	Four 2.5% taps, two above and two below nominal	1500kVA, 150˚C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
13A	3	15-500	96-150 kV	Four 2.5% taps, two above and two below nominal	300kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL
13B	3	750-2500	96-150 kV	Four 2.5% taps, two above and two below nominal	2000kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL

D.3.1 **Medium-Voltage Dry-Type Design Lines:** Please comment on the appropriateness of the design lines and representative units chosen for the medium-voltage dry-type distribution transformers. Should any other representative units be selected, and why? Would these other representative units experience different incremental costs for increasing efficiency as compared to the current rep units?

D.3.2 **Dimension and Weight Constraints:** For each of the representative units, are there any weight constraints or dimensional constraints for customer applications that DOE should be aware of? If so, please specify the maximum weight and/or dimensions that are feasible.

Design Option Combinations

For each representative unit, DOE is considering several design option combinations that characterize a range of efficiency levels for distribution transformers. This range spans from the efficiency level requirements set forth in DOE's 2007 final rule to the maximum technologically available level ("max tech"). Within this range, DOE considers several discrete candidate standard levels (CSLs) for setting the efficiency standard. The following tables present the CSL efficiency level and request feedback on the design options available to reach that efficiency level, the manufacturer's production cost (MPC) of the lowest first-cost design at that level, and the manufacturer's selling price (MSP) for that design. The MPC consists of all direct and indirect production costs, and the MSP includes the MPC plus non-production costs (e.g., SG&A, R&D, profit factor, etc.).

Design Line 9
(300kVA, 150˚C, three-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
Example: 99.12		≥M3 (conventional core) miter only; ≥M5 (symmetric core); Al or Cu	6,560	8,200
0	98.82			
1	98.97			
2	99.12			
3	99.28			
4	99.43			
5	99.58			

Design Line 10
(1500kVA, 150˚C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	99.22			
1	99.31			
2	99.40			
3	99.50			
4	99.59			
5	99.68			

Design Line 11
(300kVA, 150˚C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	98.67			
1	98.84			
2	99.00			
3	99.17			
4	99.33			
5	99.50			

Design Line 12
(1500kVA, 150˚C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	99.12			
1	99.21			
2	99.30			
3	99.39			
4	99.48			
5	99.57			
6	99.66			

Design Line 13A
(300kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	98.63			
1	98.80			
2	98.96			
3	99.13			
4	99.29			
5	99.45			

Design Line 13B
(2000kVA, 150˚C, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL)

CSL	Efficiency Level [%]	Design Options Available	MPC of lowest first-cost design [$]	MSP of lowest first-cost design [$]
0	99.15			
1	99.25			
2	99.35			
3	99.46			
4	99.56			
5	99.66			

D.3.3 **Amorphous Cores in Large kVA Designs:** DOE understands that amorphous cores in large distribution transformers (1500 kVA and greater) require additional labor and hardware costs above and beyond the requirements for other core steels in these designs. The labor accounts for extra handling required for these large, fragile designs, and the hardware costs account for additional bracing to prevent short circuit problems. Please comment on how these costs compare between amorphous designs and other designs using the table below.

Direct Labor and Bracing Costs for Design Line 12
(1500kVa, 150˚ C, three-phase, 60 Hz, 12470V primary, 480Y/277V secondary, 95kV BIL)

Core Steel	Direct Labor for Typical Design [*hours*]	Bracing Costs for Typical Design [$]	Comments
M6			
M5			
M4			
M3			
H-0 DR			
SA1 (Amorphous)			

4 MATERIALS PRICES, MARKUPS, AND LABOR RATES

Materials Prices

DOE gathers materials price data for the five years between 2006 and 2010, and plans to use the 2010 materials prices for the reference case of its analysis.

D.4.1 **Copper and Aluminum Indices:** DOE is considering setting its copper and aluminum materials prices based on the commodity's index price plus a processing cost markup. DOE would consider the current (2011) index value and scale it back through 2006 using the producer price index. DOE would then apply a processing cost to the commodity price that varies for each of DOE's groupings (e.g., wire vs. strip, different gauges, etc.). Please comment on DOE's proposed methodology for deriving copper and aluminum prices.

D.4.2 **Copper and Aluminum Processing Costs:** To account for the processing costs of converting copper and aluminum into wire and strip, is it appropriate to apply a markup to the underlying commodity price, or a straight adder? In the table below, please indicate the appropriate markup or price adder for each of the types of copper and aluminum.

Processing Costs for Copper and Aluminum

Material	Processing Cost Markup [%] or Adder [$]	Comments
Copper wire, formvar, round #10-20		
Copper wire, enameled, round #7-10 flattened		
Copper wire, enameled, rectangular sizes		
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped		
Aluminum wire, formvar, round #9-17		
Aluminum wire, formvar, round #7-10		
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped		
Aluminum wire, rectangular #<7		
Copper strip, thickness range 0.02-0.045		
Copper strip, thickness range 0.030-0.060		
Aluminum strip, thickness range 0.02-0.045		
Aluminum strip, thickness range 0.045-0.080		

D.4.3 **Materials Prices:** The following table contains DOE's estimates for material prices for distribution transformers in each of the past five years. The prices listed do not include any markups for scrap, handling, factory overhead, non-production costs, or profit, but rather represent the price a manufacturer would pay for the material, including any bulk purchase discounts. All prices are listed in historic dollars (e.g., $2007 for year 2007). Does your company pay a similar price for these materials? If not, what price does your company pay?

Materials Prices for Distribution Transformers

Material	Units	2010	2009	2008	2007	2006	Comments
M36 core steel (26 gauge)	*$/lb*	0.66	0.66	0.66	0.80	0.57	
M19 core steel (26 gauge)	*$/lb*	0.91	0.81	0.94	0.91	0.70	
M12 core steel	*$/lb*	1.03	1.08	1.25	1.19	1.05	
M6 core steel	*$/lb*	1.46	1.62	1.72	1.52	1.18	
M5 core steel	*$/lb*	1.51	1.65	1.76	1.55	1.23	
M4 core steel	*$/lb*	1.59	1.69	1.80	1.58	1.29	
M3 core steel	*$/lb*	1.88	1.95	2.05	1.64	1.32	
M2 core steel	*$/lb*	2.00	1.99	2.19	2.09	1.64	
H-O DR core steel (laser scribed)	*$/lb*	2.06	2.36	2.54	2.18	1.76	
ZDMH (mechanically-scribed core steel)	*$/lb*	2.05	2.01	2.53	2.20	1.75	
SA1 (amorphous) finished core, volume production	*$/lb*	2.38	2.27	2.86			
Copper wire, formvar, round #10-20	*$/lb*	4.45	3.97	4.44	4.50	4.21	
Copper wire, enameled, round #7-10 flattened	*$/lb*	4.85	4.37	4.84	4.90	4.61	
Copper wire, enameled, rectangular sizes	*$/lb*	4.81	4.33	4.80	4.86	4.57	
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped	*$/lb*	4.95	4.47	4.94	5.00	4.71	
Aluminum wire, formvar, round #9-17	*$/lb*	2.47	2.40	2.53	2.48	2.47	
Aluminum wire, formvar, round #7-10	*$/lb*	2.17	2.10	2.23	2.18	2.17	
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped	*$/lb*	1.68	1.61	1.74	1.69	1.68	
Aluminum wire, rectangular #<7	*$/lb*	2.04	1.97	2.10	2.05	2.04	
Copper strip, thickness range 0.02-0.045	*$/lb*	5.15	4.67	5.14	5.20	4.91	
Copper strip, thickness range 0.030-0.060	*$/lb*	5.05	4.57	5.04	5.10	4.81	
Aluminum strip, thickness range 0.02-0.045	*$/lb*	2.07	2.00	2.13	2.08	2.07	
Aluminum strip, thickness range 0.045-0.080	*$/lb*	2.08	2.01	2.14	2.09	2.08	
Kraft insulating paper with diamond adhesive	*$/lb*	1.52	1.53	1.52	1.50	1.46	
Nomex insulation	*$/lb*	24.50	24.50	22.80	19.89	17.07	
Cequin insulation	*$/lb*	5.53	5.07	4.78	4.93	4.78	
Mineral oil	*$/gal*	3.35	2.87	3.02	2.42	2.42	
Impregnation	*$/gal*	22.55	22.50	21.45	21.35	21.35	
Winding combs	*$/lb*	12.34	12.58	12.10	11.52	7.56	
Tank/Enclosure Steel	*$/lb*	0.38	0.38	0.47	0.41	0.40	

Markups
DOE applies markups to all costs to reflect a manufacturer's internal markups. This interview guide does not go into detail on all the markups, but further information can be found online.[2]

DOE defines factory overhead as the indirect costs associated with production, indirect materials and energy use (e.g., annealing furnace), taxes, and insurance. In the preliminary analysis, DOE estimated this cost based on a markup applied to direct material production costs. However, DOE received comments stating that factory overhead should be derived from labor costs or based on a fixed amount per design option.

D.4.4 **Factory Overhead:** How can DOE best characterize factory overhead costs? If DOE should apply a markup to labor costs, what markup is appropriate, and should it be applied to labor hours or labor cost? If DOE should account for a fixed overhead amount for each design option, what overhead amounts are appropriate for the design options considered by DOE for each of the representative units? Does factory overhead change with kVA size?

2 Preliminary Analysis: Chapter 5 – Engineering Analysis (pp. 39-41). Available here: http://www1.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/transformer_preanalysis_ch5.pdf.

5 SCALING RESULTS

DOE scales its analysis on the representative units to the other kVA ratings that are not directly analyzed. In the preliminary analysis, DOE relied on the 0.75 scaling rule to scale efficiency and cost. DOE received comments that the 0.75 scaling rule may not provide accurate results beyond more than a few standard kVA ratings from the reference rating.

D.5.1 **The 0.75 Scaling Rule:** How accurate is the 0.75 scaling rule when scaling efficiency? When scaling cost? For DOE's specific design lines and representative units, which kVA ratings would vary the most between the scaled cost/efficiency and the actual cost/efficiency?

D.5.2 **Efficiency Adjustment Factor:** If the 0.75 scaling rule is not accurate for wider kVA ranges, would it be feasible for DOE to incrementally adjust efficiency standards for certain scaled kVA ratings within a design line? If so, please comment on which kVA ratings would require the adjustment, what the adjustment should be, and any data used to support the adjustment.

DOE has heard that the 0.75 scaling rule is generally more accurate for scaling efficiency, but that it may understate the scaled cost of designs at lower kVA ratings due to certain fixed costs that do not scale according to the 0.75 rule. These costs could include tank/enclosure costs and other fixed hardware.

D.5.3 **Scaling and Incremental Cost Impacts:** Incremental efficiency improvements are typically determined by the core and coil specifications, which scale accurately using the 0.75 scaling rule. Even if the total cost of the transformer does not scale accurately using the 0.75 scaling rule due to fixed costs, wouldn't the incremental cost for improving efficiency still be accurately represented by the 0.75 scaling rule? Why, or why not?

E. MARKET QUESTIONNAIRE

E.1 **Customer purchase evaluation rates:** What is the percentage of customers that specify A and B parameters when purchasing distribution transformers?

Customer Purchase Evaluation Rates for Distribution Transformers

	Current DOE estimate of purchasers who specify A and B parameters	**% of purchasers who specify A and B parameters**
Liquid-Immersed	75%	
Low-Voltage Dry-Type	10%	
Medium-Capacity Dry-Type	50%	
High-Capacity Dry-Type	80%	

E.2 **Refurbished Transformers:** Does your company refurbish distribution transformers? What portion of the distribution transformer market are refurbished transformers? What factors would affect customer decisions to buy new vs. refurbish? How is this expected to change if efficiency standards are increased?

E.3 **Transformers with Forced Cooling:** What percentage of distribution transformers use forced cooling? Of the transformers with forced cooling, what percentage of the time are they operating using forced cooling rather than natural cooling?

F. MANUFACTURER IMPACT ANALYSIS

The Manufacturer Impact Analysis (MIA) identifies and quantifies the likely impacts of amended energy conservation standards on manufacturers. This section of the interview guide references the equipment class groupings and design lines presented previously and repeated below.

Design Lines and Equipment Class Groupings for Distribution Transformers

Design Line	Equipment Class Grouping*	Type of Distribution Transformer	kVA Range
1	1	Liquid-immersed, single-phase, rectangular tank	10–167
2		Liquid-immersed, single-phase, round tank	10–167
3		Liquid-immersed, single-phase, round tank	250–833
4	2	Liquid-immersed, three-phase	15–500
5		Liquid-immersed, three-phase	750–2500
6	3	Dry-type, low-voltage, single-phase	15–333
7	4	Dry-type, low-voltage, three-phase	15–150
8		Dry-type, low-voltage, three-phase	225–1000
9	6	Dry-type, medium-voltage, three-phase, 20-45kV BIL	15–500
10		Dry-type, medium-voltage, three-phase, 20-45kV BIL	750–2500
11	8	Dry-type, medium-voltage, three-phase, 46-95kV BIL	15–500
12		Dry-type, medium-voltage, three-phase, 46-95kV BIL	750–2500
13A	10	Dry-type, medium-voltage, three-phase, 96-150kV BIL	15-500
13B		Dry-type, medium-voltage, three-phase, 96-150kV BIL	750–2500

* DOE did not select any representative units from the single-phase, medium-voltage equipment classes, but calculated the analytical results for them based on the results for their three-phase counterparts.

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 when conducting the MIA.

F.1.1 In general, what are the key concerns for your company regarding this distribution transformer rulemaking?

F.1.2 How would amended energy conservation standards affect your ability to compete in the marketplace?

F.1.3 The limited availability of certain core steels may pose an issue at higher efficiency levels. For each type of core steel in the table below, please indicate the names of suppliers that produce it, the estimated total global supply of it, barriers in the marketplace for obtaining it, and any other comments that you would like to make.

Core Steel Availability

Core Steel Type	Names of Suppliers	Est. Total Global Supply	Barriers to Availability	Other Comments
M4				
M3				
M2				
ZDMH				
H-0 DR				
SA1 Amorphous				
Other:				

2 Company Overview and Organizational Characteristics

Understanding how the manufacture of distribution transformers fits within your larger organization will help DOE better estimate the probable impacts of an amended energy conservation standard.

F.2.1 Do you have a parent company and/or subsidiary? If so, please provide their names.

F.2.2 What is your company's approximate market share of the distribution transformer market for: (1) liquid-immersed, (2) low-voltage dry-type, and (3) medium-voltage dry-type? Does this vary significantly for any particular design line that you manufacture?

F.2.3 What are your product line niches and relative strengths in the distribution transformer market?

F.2.4 Do you manufacture any products other than distribution transformers? If so, what other products do you manufacture? Do you manufacture them in the same facilities as your distribution transformers? What percentage of your overall revenue is from distribution transformer sales?

F.2.5 Where are your production facilities located, and what type of product is manufactured at each location? Please provide production figures for your company's manufacturing at each location by design line or equipment class grouping.

Manufacturing Locations

Location	**Design Line (DL) or Equipment Class Grouping (ECG)**	**Employees (Production)**	**Employees (Non-production)**	**Units/Yr Produced**
***Example*: Jackson, TN**	ECG #1. Liquid-immersed, medium-voltage, single-phase	75	25	680,000

F.2.6 Are higher efficiency products built at different plants than lower efficiency products of the same design line?

F.2.7 Would you expect your market share to change once amended energy conservation standards become effective?

3 MARKUPS AND PROFITABILITY

In this section, DOE would like to understand the current markup structure of the industry and how setting an amended energy conservation standard would impact your company's markup structure and profitability.

The manufacturer markup is a multiplier applied to manufacturer production cost to cover per unit research and development, selling, general, and administrative expenses, and profit. It is NOT a profit margin. The manufacturer production cost multiplied by the manufacturer markup plus the shipping costs covers all costs involved in manufacturing and profit for the product.

F.3.1 DOE calculated a markup of 1.25 for distribution transformers. How does this figure compare to your company's baseline markups? Do the markups vary by design line?

F.3.2 Within each design line, do the per-unit mark-ups vary by design options? Alternatively, does efficiency affect the markup on a product?

F.3.3 What other factors affect mark-ups in the same design line?

F.3.4 Would you expect amended energy conservation standards to affect your profitability? If so, please explain why.

4 DISTRIBUTION CHANNELS

F.4.1 **Delivery Channels for Liquid-Immersed Transformers:** What percentage of liquid-immersed distribution transformers is sold directly to utilities? What percentage of liquid-immersed transformers is sold to a utility through an independent manufacturer distributor? For each of these delivery channels what is the percentage increase in manufacturer sale price (markup factor) that will be realized in the final retail price?

Distribution Channels for Liquid-Immersed Transformers

Channel	% of Units Sold	Markup Factor
Sold directly to utilities		
Sold through a distributer		
Other, please describe:		

F.4.2 **Delivery Channels for Dry-Type Transformers:** What percentage of dry-type transformers is sold directly to electrical contractors? What percentage of dry-type transformers is sold directly to multi-site commercial/industrial customers (also known as "national accounts")? For each of these delivery channels what is the percentage increase in manufacturer sale price (markup factor) that will be realized in final retail price?

Distribution Channels Dry-Type Transformers

Channel	% of Units Sold	Markup Factor
Sold directly to electrical contractors		
Sold directly to "national accounts"		

5 Shipment Projections and Market Shares

An amended energy conservation standard can change overall shipments by altering product attributes, marketing approaches, product availability, and price. DOE's shipments model includes forecasts for the base case shipments (i.e., total industry shipments absent amended energy conservation standards) and the standards case shipments (i.e., total industry shipments with amended energy conservation standards).

To determine efficiency distributions after the compliance date of the standard, DOE modeled a shift scenario, in which products that exceed the new standard level in the base case shift to even higher efficiencies in the standards case to maintain their relative efficiency premium.

F.5.1 How do you think amended energy conservation standards will impact the sales of more efficient products? For example, would customers continue to buy products that exceed the energy conservation standard level? Would your response change for higher mandated efficiency levels?

F.5.2 How sensitive do you think shipments will be to price changes? Will it vary with equipment class grouping or design line?

F.5.3 Would you expect your market share to change when higher energy conservation standards take effect?

F.5.4 What percent of your transformer shipments come from distribution transformers?

F.5.5 To your knowledge, are there any niche manufacturers or component manufacturers for which the adoption of amended energy conservation standard would have a particularly severe impact? If so, why?

6 Financial Parameters

Navigant Consulting, Inc. (NCI) has developed a "strawman" model of financial performance called the Government Regulatory Impact Model (GRIM) using publicly available data. This section attempts to understand how your company's financial situation differs from our industry aggregate picture.

Please compare your company's distribution transformer financial parameters to the GRIM parameters tabulated below.

Financial Parameters for Distribution Transformer Manufacturers

GRIM Input	**Definition**	**Industry Estimated Value**	**Your Actual (**If Significantly Different from DOE's Estimate**)**
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)	9%	
Working Capital	Current assets less current liabilities (percentage of revenues)	16%	
SG&A	Selling, general, and administrative expenses (percentage of revenues)	16%	
R&D	Research and development expenses (percentage of revenues)	3%	
Depreciation	Amortization of fixed assets (percentage of revenues)	3%	
Capital Expenditures	Outlay of cash to acquire or improve capital assets (percentage of revenues, not including acquisition or sale of business units)	3%	
Cost of Goods Sold	Includes material, labor, overhead, and depreciation (percentage of revenues)	71%	

F.6.1 Are the figures in the table above representative of the distribution transformer industry as a whole? If not, why?

F.6.2 Do any of the financial parameters in the table above change for a particular subgroup of manufacturers? Please describe any differences.

7 Conversion Costs

An increase in energy conservation standards may cause the industry to incur capital and product conversion costs to meet the amended energy conservation standard. The MIA considers three types of conversion expenditures:

- Capital conversion costs -- One-time investments in plant, property, and equipment (PPE) necessitated by an amended energy conservation standard. These may be incremental changes to existing PPE or the replacement of existing PPE. Included are expenditures on buildings, equipment, and tooling.
- Product conversion costs – One-time investments in research, product development, testing, marketing and other costs for redesigning products necessitated by an amended energy conservation standard.
- Stranded assets -- Assets replaced before the end of their useful lives as a direct result of the change in energy conservation standard.

With a detailed understanding of the conversion costs necessitated by different standard levels, DOE can better model the impact on the distribution transformer industry resulting from amendments to the conservation standards.

F.7.1 At your manufacturing facilities, would amended energy conservation standards be difficult to implement? If so, would your company modify existing facilities or develop new facilities?

F.7.2 Are there certain design options that would require relatively minor changes to existing products? Are there certain design options where the capital or product conversion costs significantly increase? Please describe these changes qualitatively.

F.7.3 What conversion costs do you anticipate incurring with each design option? In the sections below, please indicate any significant capital and product conversion costs associated with the core steel options, core configuration options, and core type options listed. These design options are presented separately for liquid immersed, low-voltage dry-type, and medium-voltage dry-type distribution transformers.

Design Options Considered for Liquid Immersed Transformers (Design Lines 1-5)

Core Steel Options:	**Core Configuration Options:**	**Core Type Options:**
M5	Distributed Gap Wound Core	Shell
M4	Symmetric Core	Core
M3		3-Leg
M2		5-Leg
ZDMH		
SA1 Amorphous		

Capital Conversion Costs:

Product Conversion Costs:

Stranded Assets:

Design Options for Low-Voltage Dry-Type Transformers (Design Lines 6-8)

Core Steel Options:	**Core Configuration Options:**	**Core Type Options:**
M12	Stacked Butt-Lap	Shell
M6	Stacked Full Miter	Core
M5	Stacked Step-Lap Miter	3-Leg
M4	Distributed Gap Wound Core	5-Leg
M3	Symmetric Core	
M2 (wound cores)		
ZDMH (wound cores)		
H0-DR		
SA1 Amorphous		

Capital Conversion Costs:

Product Conversion Costs:

Stranded Assets:

Design Options for Medium-Voltage Dry-Type Transformers (Design Lines 9-13)

Core Steel Options:	Core Configuration Options:	Core Type Options:
M6	Stacked Full Miter	Shell
M5	Stacked Step-Lap Miter	Core
M4	Mitered Cruciform	3-Leg
M3	Distributed Gap Wound Core	5-Leg
M2 (wound cores)	Symmetric Core	
ZDMH (wound cores)		
H0-DR		
SA1 Amorphous		

Capital Conversion Costs:

Product Conversion Costs:

Stranded Assets:

F.7.4 For any design options that would require new production equipment, please describe how much downtime would be required. What impact would downtime have on your business?

8 Cumulative Regulatory Burden

Cumulative regulatory burden refers to the burden that industry faces from overlapping effects of new or revised DOE standards, and/or other regulatory actions affecting the same product or industry.

F.8.1 Are there other recent or impending standards that distribution transformer manufacturers face from DOE, other U.S. federal agencies, State regulators, foreign government agencies, or other standard setting bodies? If so, please identify the regulation and the corresponding possible effective dates for those regulations. Below is a preliminary list of regulations that could possibly affect manufacturers of distribution transformers. Please provide comments on the listed regulations.

Other Regulations Identified by DOE

Regulation	Compliance Date(s)	Expected Expenses / Comments
EPACT 2005 minimum efficiency levels for low-voltage dry-type distribution transformers	January 1, 2007	
DOE's 2007 Energy Conservation Standards Rulemaking for Distribution Transformers	January 1, 2010	

F.8.2 Are there any additional regulatory burdens that DOE should take into consideration? If so, please identify the regulation, the corresponding effective dates, and your expected compliance cost.

F.8.3 Under what circumstances would you be able to coordinate expenditures related to these other regulations with an amended energy conservation standard, thereby lessening the cumulative burden?

9 Direct Employment Impact Assessment

The impact of amended energy conservation standards on employment is an important consideration in the rulemaking process. This section of the interview guide seeks to explore current trends in transformer production employment and solicit manufacturer views on how domestic employment patterns might be affected by amended energy conservation standards.

F.9.1 Would your domestic employment levels be expected to change significantly under amended energy conservation standards? If so, please identify particular standard levels which may trigger changes in employment.

F.9.2 Would the workforce skills necessary under amended energy conservation standards require extensive retraining or replacement of employees at your manufacturing facilities?

10 CAPACITY/EXPORTS / FOREIGN COMPETITION / OUTSOURCING

Disparity between domestic and foreign energy conservation standards could impact exports or imports. Labor content and material changes resulting from amended energy conservation standards may impact sourcing decisions.

F.10.1 How would amended energy conservation standards impact your company's manufacturing capacity, in either the short term or the long term?

F.10.2 Absent amended energy conservation standards, are production facilities being relocated to foreign countries?

F.10.3 Would amended energy conservation standards impact your domestic vs. foreign manufacturing decision?

F.10.4 What percentage of your U.S. production of distribution transformers is exported?

F.10.5 What percentage of the U.S. market for distribution transformers is imported? Would amended energy conservation standards have an impact on foreign competition?

F.10.6 Are there any foreign companies with North American production facilities?

11 CONSOLIDATION

Amended energy conservation standards can alter the competitive dynamics of the market. This can include prompting companies to enter or exit the market, or to merge. DOE and the Department of Justice are both interested in any potential reduction in competition that would result from an amended energy conservation standard.

F.11.1 Please comment on industry consolidation and related trends over the last 10 years.

F.11.2 In the absence of amended energy conservation standards, do you expect any further industry consolidation? Please describe your expectations.

F.11.3 How would industry competition change as a result of amended energy conservation standards?

F.11.4 To your knowledge, are there any niche manufacturers for which the adoption of amended energy conservation standards would have a particularly severe impact?

12 Impacts On Small Business

F.12.1 The Small Business Association (SBA) denotes a small business in the distribution transformer industry as having less than 750 employees.[3] By this definition, is your company considered a small business?

F.12.2 Below is a list of small business distribution transformer manufacturers compiled by DOE. Are there any small manufacturers that should be added to this list? Are there specific manufacturers on this list that may be more severely impacted by an amended energy conservation standard than others?

CARTE International, Inc.	Moloney Electric Inc. (Canadian)
Central Moloney, Inc.	NEELTRAN
DYNAPOWER	Niagara Transformer Corporation
Electric Service Company (ELSCO)	Olsun Electrics Corporation
Federal Pacific	ONYX Power Inc.
Hex Tec, LLC (subsidiary of MSE, Inc.)	Pacific Crest Transformers
Jefferson Electric	Pemco Corporation
JINPAN International USA, Limited	Power Partners, Inc.
Kentucky Association of Electric Cooperatives, Inc.	Power Quality International
Lindsey Manufacturing Company	Powersmiths Int'l (Canadian)
Magnetic Technologies, Inc.	Sola/Hevi-Duty
Manufacturing Systems & Equipment, Inc. (MSE)	VanTran Industries, Inc.
Marcus Transformer (Canadian)	Virginia Transformer
MGM Transformer Company	Warner Power
Mirus International (Canadian)	

F.12.3 Are there any reasons that a small business might be at a disadvantage relative to a larger business under amended energy conservation standards? Please consider such factors as technical expertise, access to capital, bulk purchasing power for materials/components, engineering resources, and any other relevant issues.

[3] DOE uses the SBA small business size standards effective November 5, 2010 to determine whether a company is a small business. To be categorized as a small business, a power, distribution and specialty transformer manufacturer and its affiliates may employ a maximum of 750 employees. The 750 employee threshold includes all employees in a business's parent company and any other subsidiaries.

APPENDIX 12-B: GOVERNMENT REGULATORY IMPACT MODEL (GRIM) OVERVIEW

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APPENDIX 12-B. **GOVERNMENT REGULATORY IMPACT MODEL (GRIM) OVERVIEW**

12-B.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 base case) and under different trial standard levels (TSLs) (*i.e.*, the standards case).

Output from the model consists of summary financial metrics, graphs of major variables, and, when appropriate, access to the complete cash flow calculation.

12-B.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 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 2045 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 2043, the discounted cash flow includes the discounted ***Terminal Value (23)***; and

(26) ***Industry Value thru the end of 2043:*** The sum of ***Discounted Cash Flows (25)***.

12-B.3 DETAILED CASH FLOW EXAMPLE

STANDARD CASE SCENARIO					Base Year			Standard Year										
			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Industry Income Statement																		
Unit Sales			5.784	6.095	6.489	9.669	9.507	8.281	7.978	8.049	8.092	8.082	8.032	7.994	7.966	7.943	7.916	7.886
Revenues			1,488.636	1,568.587	1,669.967	2,488.493	2,446.781	2,954.606	2,846.633	2,871.803	2,887.256	2,883.672	2,865.784	2,852.448	2,842.966	2,834.950	2,825.675	2,815.208
Cost of Sales																		
	Labor	11.2%	166.243	175.172	186.493	277.902	273.244	251.418	242.229	244.374	245.685	245.375	243.850	242.699	241.871	241.170	240.363	239.455
	Material	53.7%	799.267	842.194	896.626	1,336.103	1,313.708	1,735.577	1,672.153	1,686.930	1,696.011	1,693.913	1,683.408	1,675.603	1,670.073	1,665.401	1,659.988	1,653.874
	Overhead	8.5%	126.344	133.130	141.734	211.204	207.664	172.541	166.239	167.711	168.616	168.408	167.364	166.572	165.999	165.511	164.949	164.319
	Depreciation	3.4%	48.869	51.493	54.821	81.692	80.322	96.655	93.123	93.946	94.452	94.335	93.750	93.314	93.003	92.741	92.437	92.095
	Shipping		40.734	42.921	45.695	68.093	66.951	88.734	85.490	86.248	86.709	86.598	86.060	85.660	85.376	85.138	84.862	84.550
	Stranded Assets		$ -	$ -	$ -	$ -	$ -	$ 16.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Selling, General and Administrative																		
	Standard SG&A		$ 186.8	$ 196.8	$ 209.5	$ 312.2	$ 307.0	$ 370.7	$ 357.1	$ 360.3	$ 362.2	$ 361.8	$ 359.5	$ 357.9	$ 356.7	$ 355.7	$ 354.5	$ 353.2
	R&D	2.2%	$ 32.7	$ 34.5	$ 36.7	$ 54.7	$ 53.8	$ 65.0	$ 62.6	$ 63.2	$ 63.5	$ 63.4	$ 63.0	$ 62.8	$ 62.5	$ 62.4	$ 62.2	$ 61.9
	Product Conversion Costs		$ -	$ -	$ 28.7	$ 40.1	$ 45.9	$ 2.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Earnings Before Interest and Taxes (EBIT)		5.7%	$ 87.7	$ 92.4	$ 69.7	$ 106.4	$ 98.2	$ 155.6	$ 167.6	$ 169.1	$ 170.0	$ 169.8	$ 168.8	$ 168.0	$ 167.4	$ 166.9	$ 166.4	$ 165.8
EBIT/Revenues			5.9%	5.9%	4.2%	4.3%	4.0%	5.3%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%
Taxes			$ 29.7	$ 31.3	$ 23.6	$ 36.1	$ 33.3	$ 52.7	$ 56.8	$ 57.3	$ 57.6	$ 57.6	$ 57.2	$ 56.9	$ 56.8	$ 56.6	$ 56.4	$ 56.2
Net Operating Profit after Taxes (NOPAT)			$ 57.9	$ 61.1	$ 46.1	$ 70.3	$ 64.9	$ 102.8	$ 110.8	$ 111.8	$ 112.4	$ 112.2	$ 111.6	$ 111.0	$ 110.7	$ 110.3	$ 110.0	$ 109.6
Cash Flow Statement																		
	NOPAT		$ 57.9	$ 61.1	$ 46.1	$ 70.3	$ 64.9	$ 102.8	$ 110.8	$ 111.8	$ 112.4	$ 112.2	$ 111.6	$ 111.0	$ 110.7	$ 110.3	$ 110.0	$ 109.6
	Depreciation		$ 48.9	$ 51.5	$ 54.8	$ 81.7	$ 80.3	$ 112.7	$ 93.1	$ 93.9	$ 94.5	$ 94.3	$ 93.7	$ 93.3	$ 93.0	$ 92.7	$ 92.4	$ 92.1
	Change in Working Capital		$ -	$ -	$ (2.9)	$ (23.7)	$ 1.2	$ (14.7)	$ 3.1	$ (0.7)	$ (0.4)	$ 0.1	$ 0.5	$ 0.4	$ 0.3	$ 0.2	$ 0.3	$ 0.3
Cash Flows from Operations			$ 106.8	$ 112.6	$ 97.9	$ 128.3	$ 146.5	$ 200.8	$ 207.1	$ 205.0	$ 206.4	$ 206.7	$ 205.8	$ 204.7	$ 203.9	$ 203.3	$ 202.7	$ 202.0
	Ordinary Capital Expenditures	3.5%	$ (52.1)	$ (54.9)	$ (58.4)	$ (87.1)	$ (85.6)	$ (103.4)	$ (99.6)	$ (100.5)	$ (101.1)	$ (100.9)	$ (100.3)	$ (99.8)	$ (99.5)	$ (99.2)	$ (98.9)	$ (98.5)
	Capital Conversion Costs		$ -	$ -	$ (48.4)	$ (67.7)	$ (77.4)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Investments			$ (52.1)	$ (54.9)	$ (106.8)	$ (154.8)	$ (163.0)	$ (103.4)	$ (99.6)	$ (100.5)	$ (101.1)	$ (100.9)	$ (100.3)	$ (99.8)	$ (99.5)	$ (99.2)	$ (98.9)	$ (98.5)
Free Cash Flow			$ 54.7	$ 57.6	$ (8.9)	$ (26.5)	$ (16.6)	$ 97.4	$ 107.43	$ 104.5	$ 105.3	$ 105.8	$ 105.5	$ 104.9	$ 104.4	$ 104.1	$ 103.8	$ 103.4
Terminal Value			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Present Value Factor			1.149	1.072	1.000	0.933	0.870	0.812	0.757	0.706	0.659	0.615	0.573	0.535	0.499	0.465	0.434	0.405
Discounted Cash Flow			$ 62.87	$ 61.80	$ (8.87)	$ (24.73)	$ (14.40)	$ 79.09	$ 81.35	$ 73.81	$ 69.41	$ 65.00	$ 60.50	$ 56.11	$ 52.11	$ 48.45	$ 45.07	$ 41.90
Industry Value thru	2043	$ 1,201.41																
Net PPE			$ 296.2	$ 312.1	$ 332.3	$ 405.4	$ 488.1	$ 478.8	$ 485.3	$ 491.9	$ 498.5	$ 505.1	$ 511.6	$ 518.1	$ 524.6	$ 531.1	$ 537.6	$ 544.0
Net PPE as % of Sales			19.9%	19.9%	19.9%	16.3%	19.9%	16.2%	17.0%	17.1%	17.3%	17.5%	17.9%	18.2%	18.5%	18.7%	19.0%	19.3%
Net Working Capital			$ 43.2	$ 45.5	$ 48.4	$ 72.2	$ 71.0	$ 85.7	$ 82.6	$ 83.3	$ 83.7	$ 83.6	$ 83.1	$ 82.7	$ 82.4	$ 82.2	$ 81.9	$ 81.6
Return on Invested Capital (ROIC)			17.07%	17.07%	12.10%	14.73%	11.61%	18.22%	19.51%	19.44%	19.30%	19.07%	18.76%	18.48%	18.23%	17.99%	17.75%	17.51%
Weighted Average Cost of Capital (WACC)			7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%
Return on Sales (EBIT/Sales)			5.89%	5.89%	4.17%	4.28%	4.01%	5.27%	5.89%	5.89%	5.89%	5.89%	5.89%	5.89%	5.89%	5.89%	5.89%	5.89%

APPENDIX 16A. SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866

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APPENDIX 16A. SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866[a]

16A.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.

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

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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

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 16A.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

16A.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.

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

[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).

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 16-A.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.

16A.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.

16A.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.

16A.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).

[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).

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 a later section, we discuss key gaps in how the models account for various scientific and 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 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

[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%, 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.

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.

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 Figures 16A.4.1 and 16A.4.2, using the modeler’s default scenarios and mean input assumptions. There are significant

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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).

differences between the three models both at lower (figure 16A.4.2) and higher (figure 16A.4.1) increases in global-average temperature.

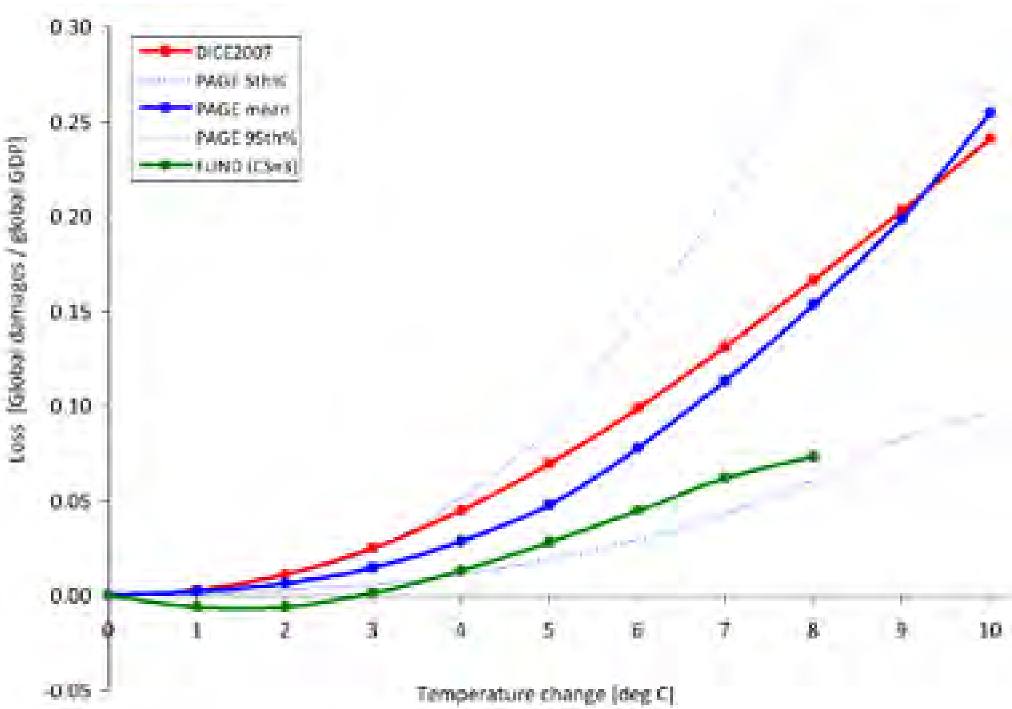

Figure 16A.4.1 Annual Consumption Loss as a Fraction of Global GDP in 2100 Due to an Increase in Annual Global Temperature in the DICE, FUND, and PAGE models[f]

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.

[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.

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.

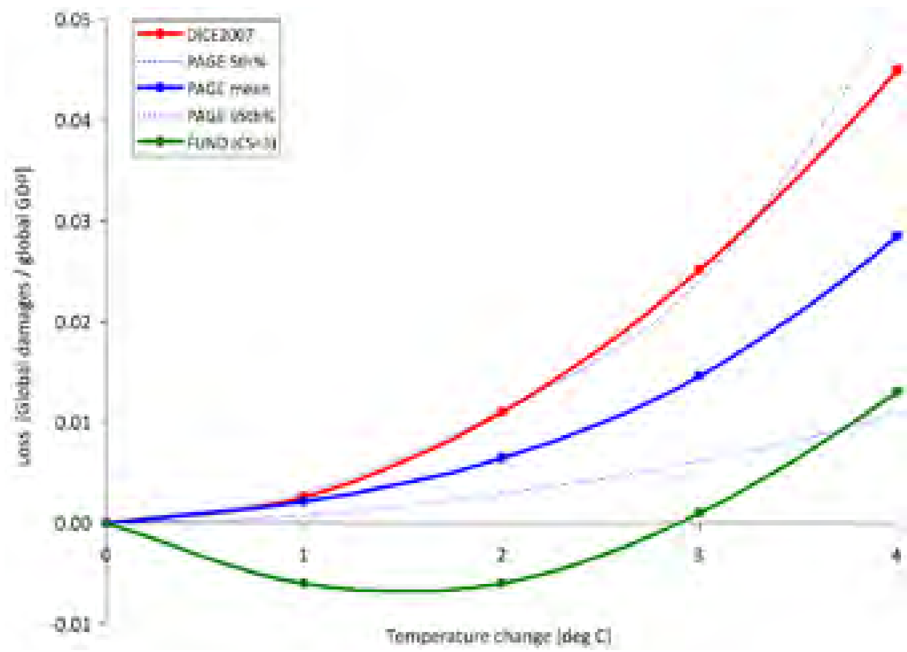

Figure 16A.4.2 Annual Consumption Loss for Lower Temperature Changes in DICE, FUND, and PAGE

16A.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

[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.

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.

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

[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.

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.

16A.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 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.

[i] Based on 2008 GDP (in current US dollars) from the *World Bank Development Indicators Report*.

16A.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 16A.4.1 included below gives summary statistics for the four calibrated distributions.

[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 16A.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";[1]
(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

[1] 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.

summarized by Newbold and Daigneault (2009). It is also closer to the mean (7.5 °C) and 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.

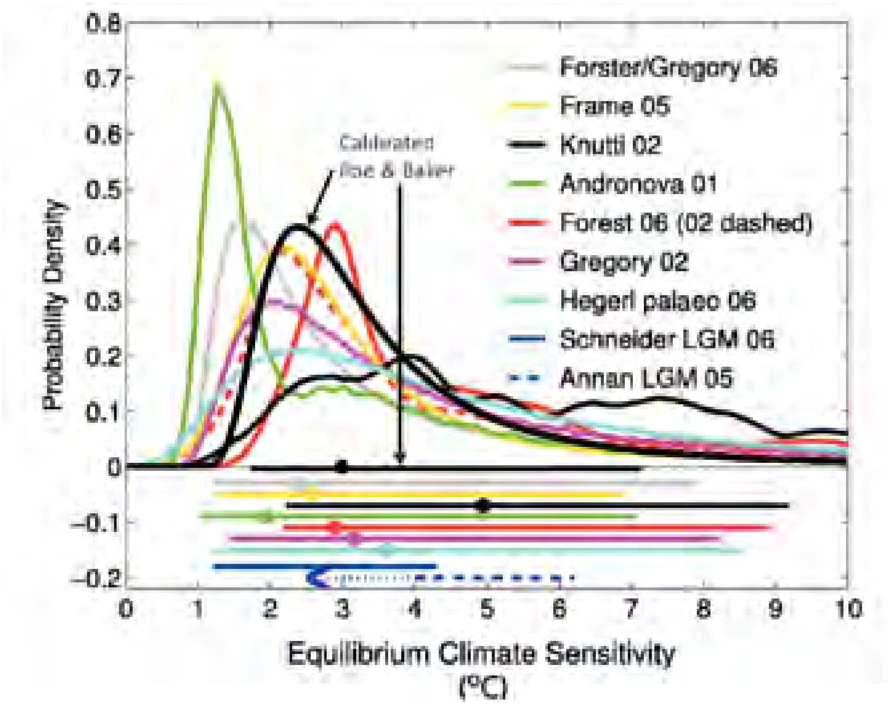

Figure 16A.4.3 Estimates of the Probability Density Function for Equilibrium Climate Sensitivity (°C)

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 16A.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.

16A.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 16A.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.

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[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 16A.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.

16A.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

[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.

non-market sectors from an additional unit of carbon dioxide emitted in a particular year in terms 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," $\rho + \eta g$, 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

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[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, since 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

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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.)

assumption that $\rho = 0.1$ percent, combined with a η of 1.5 to 2 and his original growth rate, yields a discount rate of greater than 2 percent.

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

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.

16A.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.

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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, 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).

- Constant annual discount rates of 2.5, 3, and 5 percent.

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 95^{th} 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 16A.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 16A.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 16A.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.

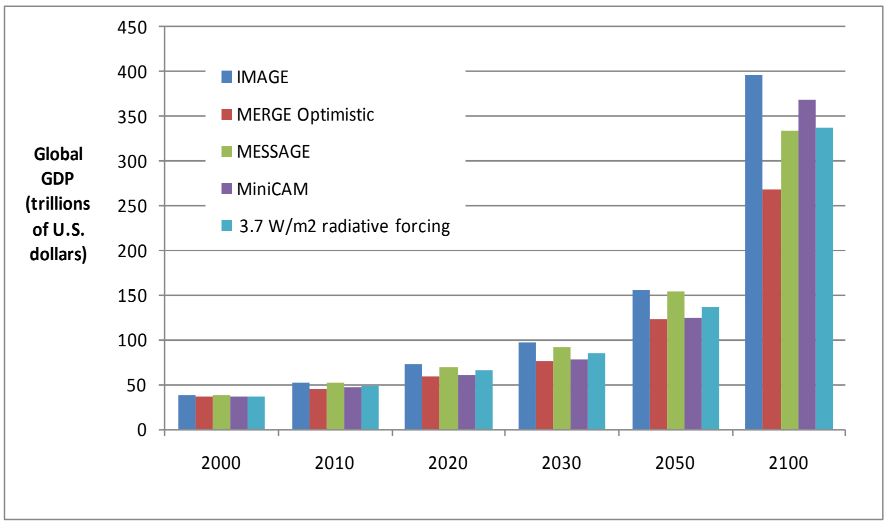

Figure 16A.5.1 Level of Global GDP across EMF Scenarios

Table 16A.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 16A.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 16A.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 16A.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]

16A.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-impact, low-probability risks, using a right-skewed gamma distribution for climate sensitivity as

[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.

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 risk-averse for such scenarios, it is possible that regulatory policy should include a degree of risk-aversion.

[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).

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.

16A.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 16A.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 16A.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 16A.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.

16A.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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16A.9 ANNEX

Table 16A.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.

16A.9.1 Other (non-CO2) 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

[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. {WGIII 3.2, TS.3, SPM}.*[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).

[gg] AR4 Synthesis Report, p. 44, http://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.

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.

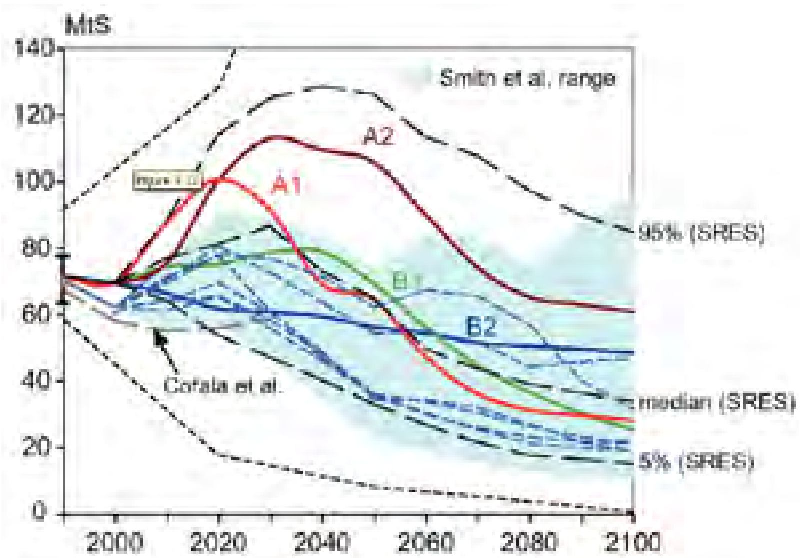

Figure 16A.9.2 Sulfur Dioxide Emission Scenarios

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, http://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.

16A.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

[jj] United Nations. 2004. *World Population to 2300*. http://www.un.org/esa/population/publications/longrange2/worldpop2300final.pdf

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.

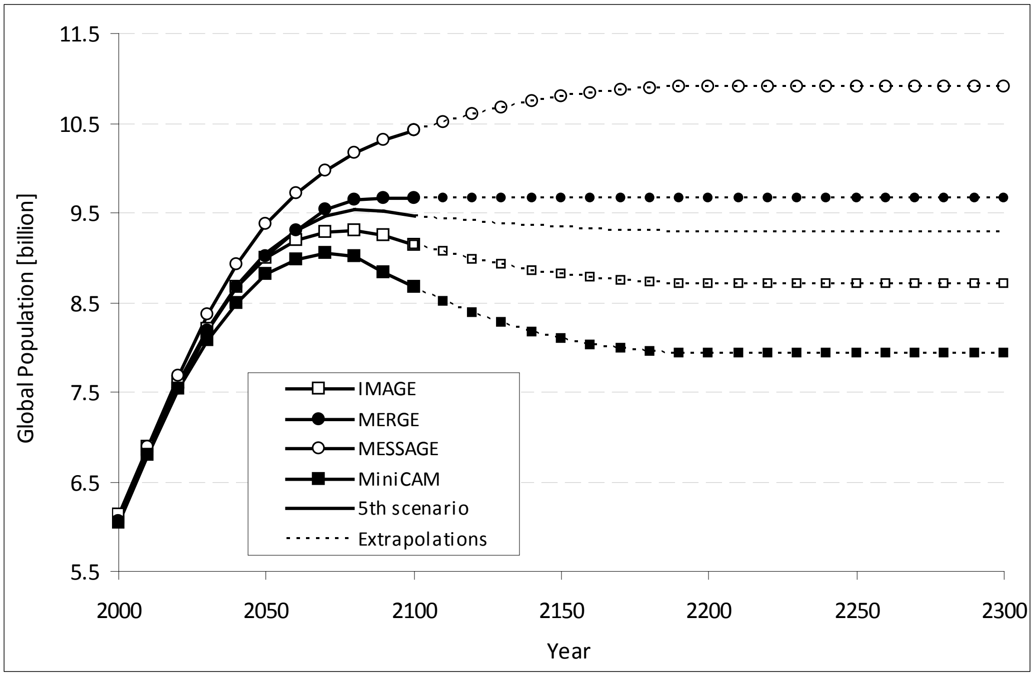

Figure 16A.9.3 Global Population, 2000-2300 (Post-2100 extrapolations assume the population growth rate changes linearly to reach a zero growth rate by 2200.)

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.

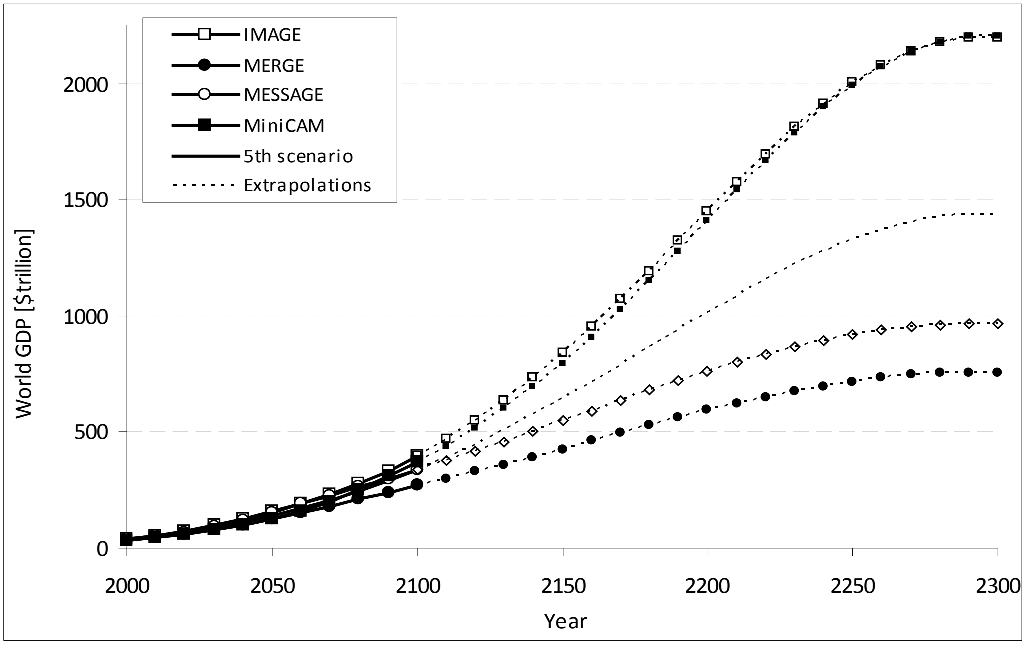

Figure 16A.9.4 World GDP, 2000-2300 (Post-2100 extrapolations assume GDP per capita growth declines linearly, reaching zero in the year 2300)

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.

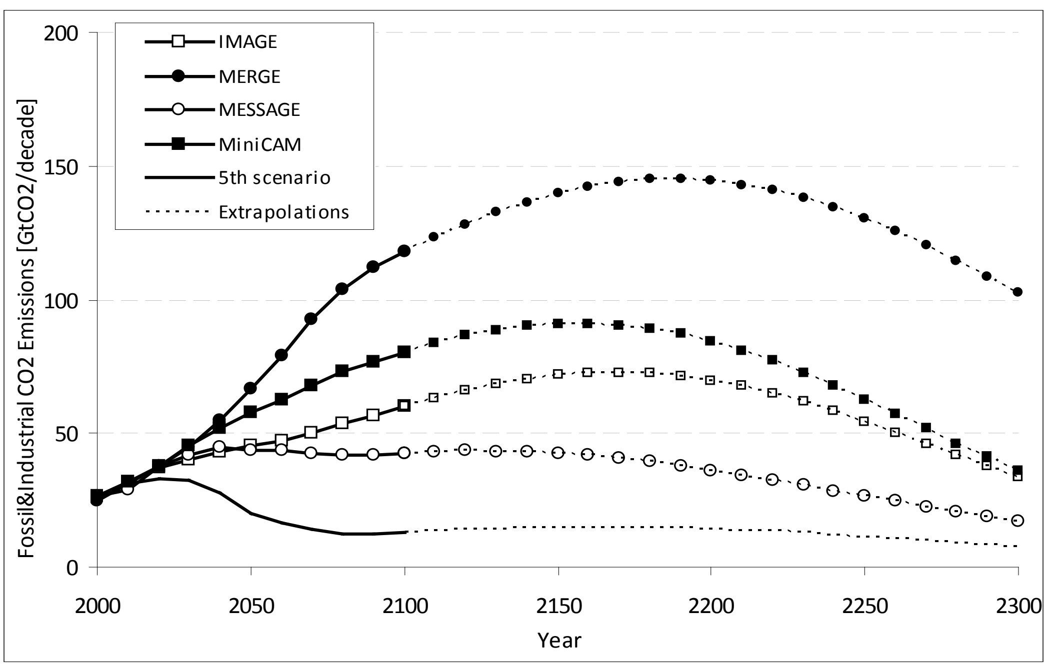

Figure 16A.9.5 Global Fossil and Industrial CO_2 Emissions, 2000-2300 (Post-2100 extrapolations assume growth rate of CO_2 intensity (CO_2/GDP) over 2090-2100 is maintained through 2300)

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.

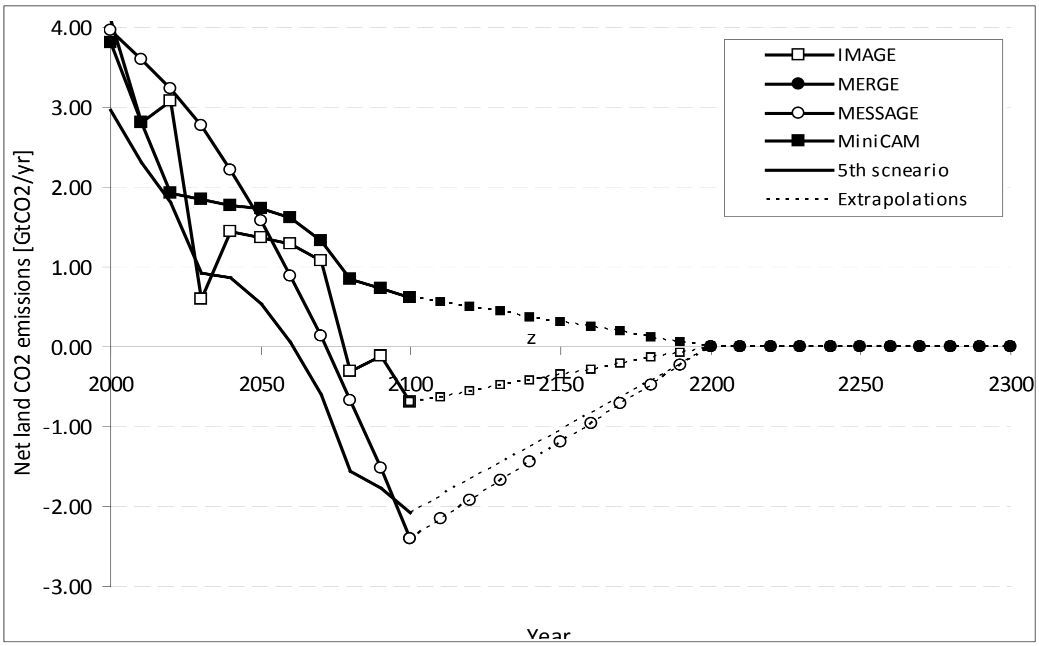

Figure 16A.9.6 Global Net Land Use CO_2 Emissions, 2000-2300 (Post-2100 extrapolations assume emissions decline linearly, reaching zero in the year 2200)[kk]

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).

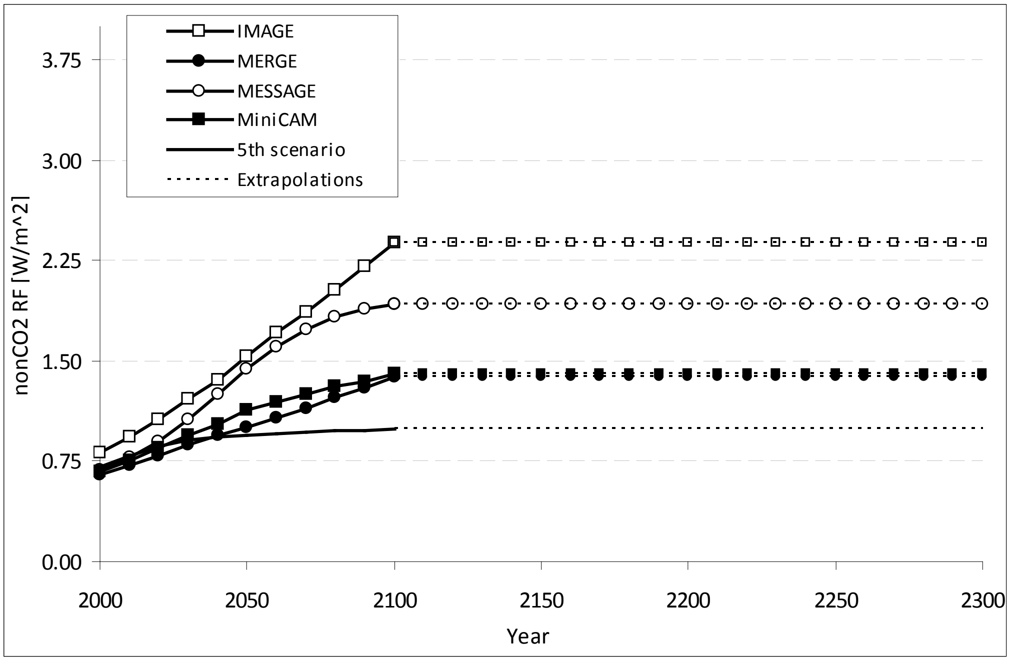

Figure 16A.9.7 Global Non-CO_2 Radiative Forcing, 2000-2300 (Post-2100 extrapolations assume constant non-CO_2 radiative forcing after 2100)

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.

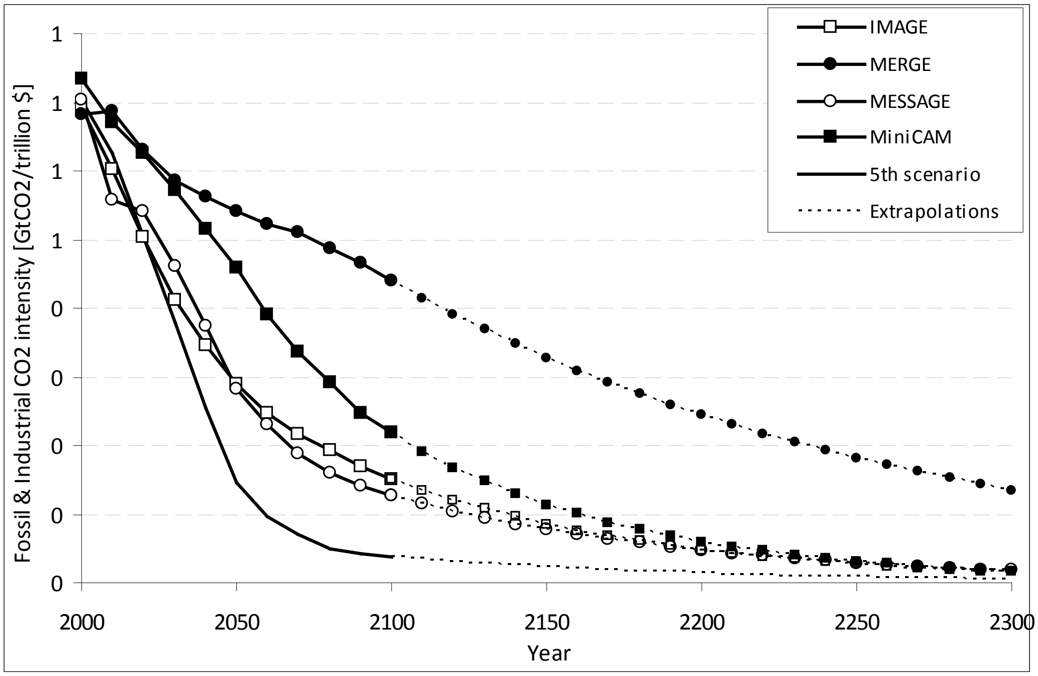

Figure 16A.9.8 Global CO_2 Intensity (fossil & industrial CO_2 emissions/GDP), 2000-2300 (Post-2100 extrapolations assume decline in CO_2/GDP growth rate over 2090-2100 is maintained through 2300)

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 16A.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 16A.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 16A.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

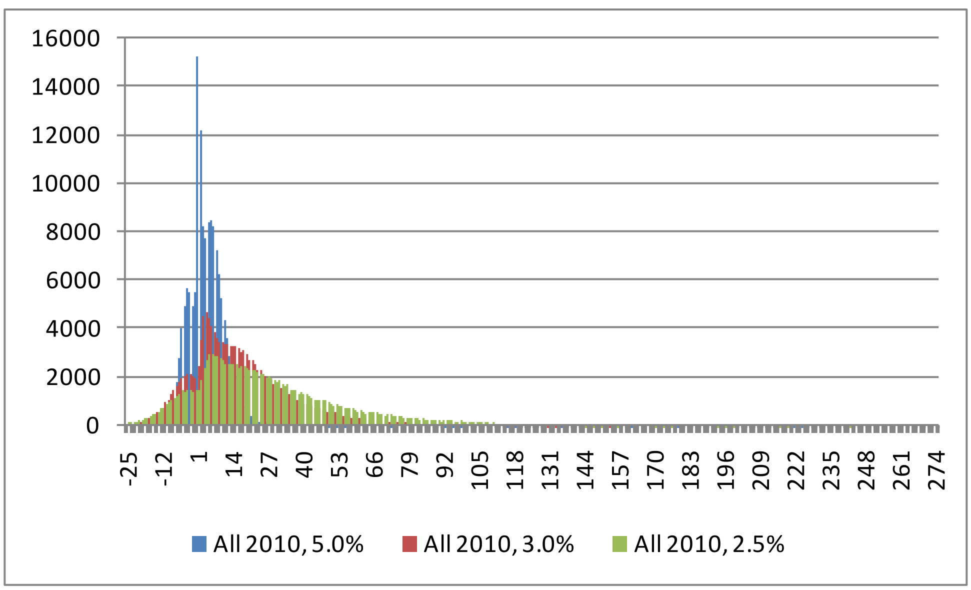

Figure 16A.9.9 Histogram of Global SCC Estimates in 2010 (2007$/ton CO_2), by discount rate

* 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.

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Table 16A.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 17A. REGULATORY IMPACT ANALYSIS SUPPORTING MATERIAL

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APPENDIX 17A. REGULATORY IMPACT ANALYSIS SUPPORTING MATERIAL

17A.1 BACKGROUND ON MARKET PENETRATION CURVES DEVELOPED BY XENERGY

Xenergy, Inc. developed a re-parameterized, mixed-source information diffusion model to estimate market impacts induced by financial incentives for energy-efficient appliances. The basic premise of this mixed-source model is that information diffusion drives technology adoption.

There is extensive economic literature on the diffusion process of new products as technologies evolve. Some of the literature focuses primarily on the development of analytical models of diffusion patterns of new products for individual consumers or for technologies from competing firms.[1,2,3] One study records researchers' attempts to investigate underlying factors that drive diffusion processes.[4] Because of the distinct characteristics of diverse new products, few studies have conclusively developed a universally-applicable model. Some key findings, however, have seemed to gain wide recognition in academia and industry.

First, new technologies may not be adopted by all potential users, regardless of their economic benefits and technological merits. Therefore, a ceiling on the adoption rate exists for many products. Second, not all adopters purchase new products at the same time; some act earlier after the introduction of a new product, while others respond slowly, waiting for products to become more mature. Third, diffusion processes can be approximately characterized by asymmetric S-curves, depicting three stages of diffusion: starting, accelerating, and decreasing as the adoption ceiling is being reached.

An important diffusion model, the <u>epidemic model</u>, is widely used in marketing and social studies on diffusion. It assumes that a) consumers value the benefits of a new product identically and b) the cost of a new product is constant or declines monotonically over time. What induces a consumer to purchase the new product is information about the availability and the benefits of the product. In other words, it is information diffusion that drives new product adoption by individual consumers.[3] The model incorporates information diffusion from both internal sources (news spread by word of mouth from early adopters) and external sources (the "announcement effect" by government, other institutions, or commercial advertising) by superimposing a logistic function with an exponential function.[1,4]

The relative degree of influence by internal or external sources determines the general shape of the diffusion curve of a specific product.[1,4] For instance, if the adoption of one particular product is more influenced by external sources of information diffusion (announcement effect) than by internal sources (word of mouth among earlier adopters to prospective adopters), the rate of diffusion at the beginning stage of the diffusion process is much higher. This reflects the immediate information exposure to a significant number of prospective adopters brought about by external sources, in contrast to the more gradual exposure to internal sources such as news propagation by earlier adopters, a small proportion of the population, to other prospective adopters. Graphically speaking, a relatively dominant external source of information diffusion gives an immediate jump-start to the adoption of a new product in the first years, forming a concave curve with respect to the Y axis (see the exponential curve in Figure A.1). Adoption of a new product with a stronger influence by internal sources of information diffusion (such as a socially-tightened network formed by prospective adopters) may start with a few early adopters and gradually increase as the number of adopters grows, and thus form a convex curve (see the logistic curve in Figure 17A.1.1).

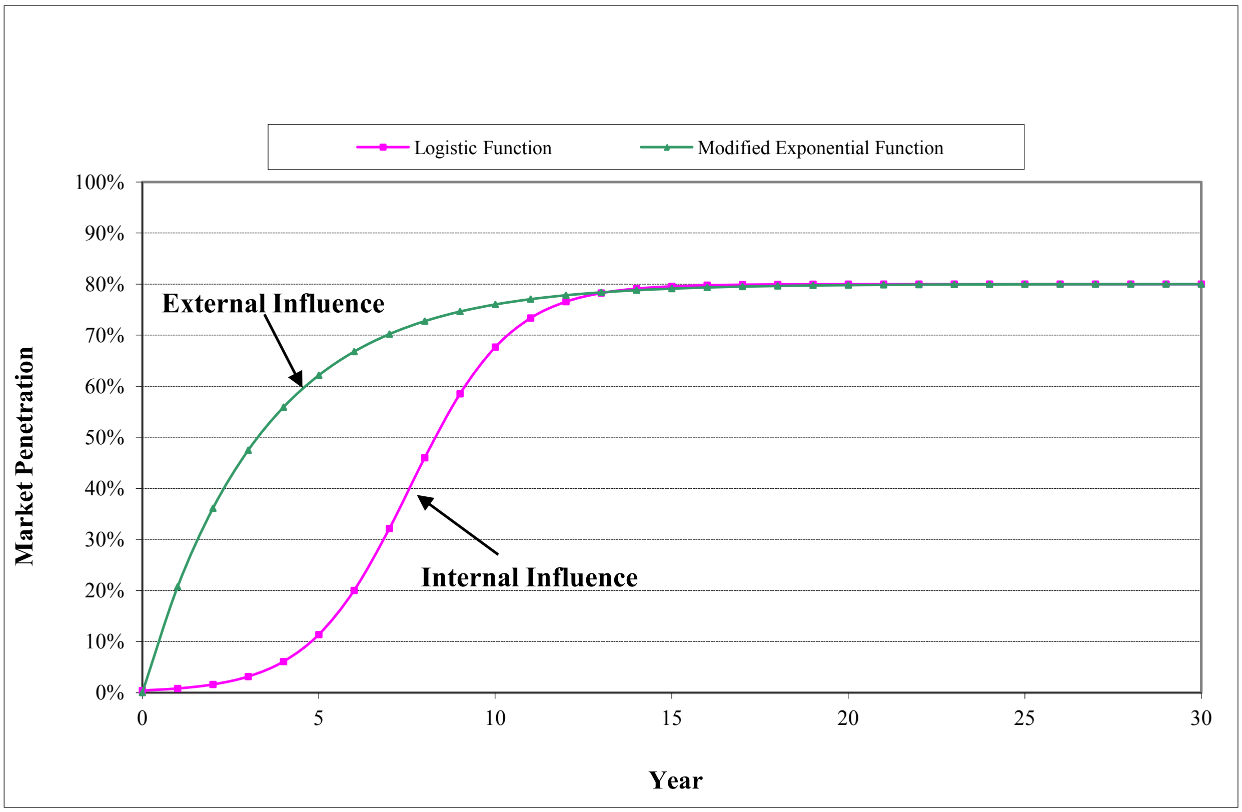

Figure 17A.1.1 Comparison of Exponential and Logistic Curves Showing External and Internal Influences on Consumers

17A.2 UTILITY REBATE PROGRAMS FOR DISTRIBUTION TRANSFORMERS

The following two tables present a summary of rebate program amounts offered throughout the U.S. for distribution transformers.

DOE found 4 agencies with programs for distribution transformers. Rebates for this product by electric utilities and municipal utilities and are generally offered under programs that cover the installation of new energy efficiency equipments up to a specified amount. These entities offer rebates for distribution transformers meeting efficiency criteria that usually greater then the current standard. The following list shows the agency names, States, and program websites of utilities with energy efficiency programs that cover distribution transformers.

- Anaheim Public Utilities, California
  http://www.anaheim.net/articlenew2222.asp?id=4136

- Austinenergy, Texas
  http://www.austinenergy.com/Energy%20Efficiency/Programs/Rebates/Commercial/Commercial%20Energy/transformerGuidelinesApp.pdf

- PECO, Pennsylvania
  https://www.pecosmartideas.com/programsandrebates/business/equipmentincentives.html

- Seattle City Light, Washington
  http://www.seattle.gov/light/conserve/business/cv5_fi.htm

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[2] Hall, B. H. and B. Khan. "Adoption of New Technology." 2003. Working Paper No.E03-330. Department of Economics, University of California, Berkeley, CA.

[3] Lekvall, P. and C. Wahlbin. "A Study of Some Assumptions Underlying Innovation Diffusion Functions." 1973. Swedish Journal of Economics.

[4] Van den Bulte, C. "Want to Know How Diffusion Speed Varies Across Countries and Products? Try a Bass Model." PDMA Vision, October 2002. Product Development and Management Association. XXVI No 4.