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

DISTRIBUTION TRANSFORMERS

August 2021

U.S. Department of Energy
Assistant Secretary
Office of Energy Efficiency and Renewable Energy
Building Technologies Program
Appliances and Commercial Equipment Standards
Washington, DC 20585

CHAPTER 1. INTRODUCTION

TABLE OF CONTENTS

TABLE OF TABLES

CHAPTER 1. INTRODUCTION

1.1 PURPOSE OF THE DOCUMENT

This preliminary technical support document (TSD) is a stand-alone report that documents the technical analyses and results in support of the information presented in the preliminary analysis for evaluating energy conservation standards for distribution transformers.

1.2 OVERVIEW OF APPLIANCE STANDARDS FOR DISTRIBUTION TRANSFORMERS

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Pub. L. 94-163 (42 U.S.C. 6291-6309, as codified), established the Energy Conservation Program for Consumer Products Other Than Automobiles. Part C of Title III of EPCA (42 U.S.C. 6311–6317) established a similar program for "Certain Industrial Equipment," including distribution transformers.[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))

On April 27, 2006, DOE prescribed test procedures for distribution transformers. 71 FR 24972. The Energy Policy Act of 2005 (Pub. Law No. 109-58, EPACT 2005) amended EPCA to establish energy conservation standards for low-voltage dry-type (LVDT) distribution transformers.[2,3](42 U.S.C. 6295(y)) On October 12, 2007, DOE established energy conservation standards for liquid-immersed distribution transformers and medium-voltage, dry-type (MVDT) distribution transformers. 72 FR 58190. On April 18, 2013, DOE amended the energy conservation standards for liquid-immersed, MVDT and LVDT distribution transformers (hereafter referred to as the April 2013 standards final rule).[4] 78 FR 23336.

---

[1] For editorial reasons, upon codification in the U.S. Code, Parts B and C were redesignated as Parts A and A-1, respectively**.**

[2] EPACT 2005 established that 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).

[3] Although certain provisions pertaining to distribution transformers, including test procedures and standards for LVDT distribution transformers, have been established in the part of EPCA generally applicable to consumer products (See, 42 U.S.C. 6291(35), 6293(b)(10), 6295(y)), they are commercial equipment. Accordingly, DOE has established the regulatory requirements for distribution transformers, including LVDT distribution transformers, in 10 CFR Part 431, Energy Efficiency Program for Certain Commercial and Industrial Equipment. See, 70 FR 60407 (October 18, 2005).

[4] The Technical Support Document for the April 2013 standards final rule is available at the following: https://www.regulations.gov/document?D=EERE-2010-BT-STD-0048-0760

The current test procedures for distribution transformers are codified in 10 CFR part 431, subpart K, appendix A. The current energy conservation standards for distribution transformers are codified at 10 CFR part 431.196.

1.3 PROCESS FOR SETTING ENERGY CONSERVATION STANDARDS

DOE must follow specific statutory criteria for prescribing new or amended standards for covered equipment, including distribution transformers. EPCA requires that any new or amended energy conservation standard be designed to achieve the maximum improvement in energy or water efficiency that is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A); see also 42 U.S.C. 6317(a)(1)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3); see also 42 U.S.C. 6317(a)(1)) Moreover, DOE may not prescribe a standard: (1) for certain equipment, including distribution transformers, if no test procedure has been established for the equipment, or (2) if DOE determines by rule that the standard is not technologically feasible or economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(A)-(B); see also 42 U.S.C. 6317(a)(1)) In deciding whether a proposed standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)) DOE must make this determination after receiving comments on the proposed standard, and by considering, to the greatest extent practicable, the following seven statutory factors:

1. The economic impact of the standard on the manufacturers and on the consumers of the products subject to such standard;
2. The savings in operating costs throughout the estimated average life of the covered product in the type (or class) compared to any increase in the price of, or in the initial charges for maintenance expenses of, the covered products which 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 standard;
5. The impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the standard;
6. The need for national energy conservation; and
7. Other factors the Secretary considers relevant.

Other statutory requirements are set forth in (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII))

DOE considers stakeholder participation to be a very important part of the process for setting energy conservation standards. Through formal public notifications (*i.e.*, Federal Register notices), DOE actively encourages the participation and interaction of all stakeholders during the comment period in each stage of the rulemaking. Beginning with the request for information (RFI) and during subsequent comment periods, interactions among stakeholders provide a balanced discussion of the information that is required for the standards rulemaking.

After publication of the request for information, the energy conservation standards rulemaking process involves three additional, formal public notices, which DOE publishes in the Federal Register. The first of the rulemaking notices is a notice of public meeting and availability of preliminary technical support document (Preliminary Analysis), 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 second notice is the notice of proposed rulemaking (NOPR), which presents a discussion of comments received in response to the preliminary analyses and analytical tools; analyses of the impacts of potential amended energy conservation standards on consumers, manufacturers, and the Nation; DOE's weighting of these impacts of amended energy conservation standards; and the proposed energy conservation standards for each product or equipment. The third 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 or equipment; and the effective dates of the amended energy conservation standards. Table 1.3.1 lists the analyses conducted at each stage of the rulemaking.

Table 1.3.1 Analyses Under the Process Rule

Preliminary Analyses	**NOPR**	**Final Rule**
Market and technology assessment	Revised preliminary analyses	Revised NOPR analyses
Screening analysis	Life-cycle cost sub-group analysis	
Engineering analysis	Manufacturer impact analysis	
Markups for equipment price determination	Environmental assessment	
Life-cycle cost and payback period	Employment impact analysis	
Shipment analysis	Regulatory impact analysis	
National impact analysis		
Preliminary manufacturer impact analysis		

1.4 HISTORY OF DISTRIBUTION TRANSFORMER STANDARDS

The Energy Policy Act of 2005 (EPACT 2005) amended EPCA to establish energy conservation standards for low-voltage dry-type distribution transformers (LVDTs). (Public Law 109-58, Section 135(c); 42 U.S.C. 6295(y)). DOE incorporated these statutory standards into its regulations, along with the standards for several other types of products and equipment, in a final rule published on October 18, 2005. 70 FR 60407, 60416-60417. On April 27, 2006, DOE prescribed test procedures for distribution transformers. 71 FR 24972. On October 12, 2007, DOE established energy conservation standards for liquid-immersed distribution transformers and MVDT distribution transformers (hereafter referred to as the October 2007 standards final rule). 72 FR 58190.

After the publication of the October 2007 standards 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 MVDT 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. To expedite the rulemaking process, DOE began at the preliminary analysis stage. 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 preliminary TSD addressing a range of issues. These comments were discussed in the various sections of the NOPR and final rule.

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 MVDT and liquid-immersed distribution transformers. 76 FR 45471. Stakeholders strongly supported a consensual rulemaking effort. 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 LVDT 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 MVDT and liquid-immersed distribution transformers held eight separate meetings from September 15, 2011 through December 1, 2011; the ERAC subcommittee also held public webinars on November 17 and December 14. DOE presented its draft engineering, life-cycle cost and national impacts analysis and results during these meetings and heard from subcommittee members on several topics. In addition, DOE presented its revised analysis, including life-cycle cost sensitivities based on exclusion of ZDMH and amorphous steel as core materials.

At the conclusion of the final meeting, subcommittee members presented their efficiency level recommendations. For liquid-immersed distribution transformers, the energy efficiency 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").[5,6] 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 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 liquid-immersed distribution transformers. For MVDT distribution transformers, the subcommittee arrived at consensus and recommended a standard of EL2 for DLs 11 and 12, from which the standards for DLs 9, 10, 13A, and 13B would be scaled.[7]

The ERAC subcommittee held six separate meetings from September 28, 2011 through December 2, 2011 for LVDT distribution transformers. The ERAC subcommittee also held webinars on November 21, 2011, and December 20, 2011. DOE presented its draft engineering, life-cycle cost and national impacts analysis and results during these meetings, in addition to

---

[5] DOE created 14 engineering design lines (DLs) on which to perform detailed engineering analysis. These DLs were selected to be collectively representative of distribution transformers in general. Results from the analysis of each DL were scaled to equipment classes not directly analyzed. DLs differentiated 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 distribution transformers (three different BIL levels). For the current preliminary analysis, the term "design line" is no longer used; instead, DOE is using the term "representative unit". Further discussion on this update is provided in chapter 5 of the TSD.

[6] DOE analyzed designs over a range of efficiency values. However, DOE analyzed only incremental impacts of increased efficiency by comparing discrete efficiency benchmarks to a baseline efficiency level. The baseline efficiency level evaluated for each representative unit (EL 0) was the existing energy conservation standard level of efficiency for distribution transformers. The incrementally higher efficiency benchmarks are referred to as "efficiency levels" (ELs) and, along with MSP values, characterize the cost-efficiency relationship above the baseline. For liquid-immersed distribution transformers, DOE analyzed either 7 or 8 ELs per DL, with EL 7 or 8 being the most efficient.

[7] For MVDT distribution transformers, DOE analyzed either 7 or 8 ELs per DL, with EL 7 or 8 being the most efficient.

presenting revised analysis and hearing from subcommittee members on various topics. DOE also presented revised analysis based on 2011 core-material prices.

At the conclusion of the final meeting, subcommittee members presented their energy efficiency level recommendations. For LVDT distribution transformers, the Advocates, represented by ASAP, recommended EL 4 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.[8] The subcommittee did not arrive at consensus regarding a proposed standard for LVDT distribution transformers. Transcripts of the subcommittee meetings and all data and materials presented at the subcommittee meetings are available at the DOE website at: *https://www.regulations.gov/docket?D=EERE-2011-BT-STD-0051*.

On February 10, 2012, DOE published a NOPR which proposed amended standards for all three transformer categories. 77 FR 7282. MVDT distribution transformers were proposed at the negotiating committee's consensus level. Liquid-immersed distribution transformers were proposed at trial standard level (TSL) 1.[9] LVDT distribution transformers were proposed at TSL 1.

In response to the NOPR, DOE received several comments expressing a desire to see some of the NOPR suggestions extended and analyzed for liquid-immersed distribution transformers. In response, DOE generated supplementary analysis to the NOPR presenting possible new equipment classes, including those for pole-mounted distribution transformers, network/vault-based distribution transformers, and those with high basic impulse level (BIL) ratings. On June 4, 2012, DOE published a notice announcing the availability of this supplementary analysis[10] and of a public meeting to be held on June 20, 2012 to present and receive feedback on it.

Following the public meeting for the supplementary NOPR analyses, DOE received comments from a number of stakeholders. Although comments varied, DOE concluded that many stakeholders believed the new equipment classes presented within the supplementary analysis were not warranted at the standard levels under consideration in the NOPR. As a result, DOE adopted the liquid-immersed energy conservation standards and equipment classes proposed in the NOPR in the final rule.

On April 18, 2013, DOE published the final rule with amended standards for all three transformer types, which included liquid immersed, LVDT and MVDT distribution transformers. 78 FR 23336. In the final rule, DOE adopted TSL 1 for liquid-immersed distribution transformers. DOE noted that the potential for significant disruption in the steel supply market at

---

[8] For LVDT distribution transformers, DOE analyzed 7 ELs per DL, with EL 7 being the most efficient.

[9] Trial standard levels are formed by grouping certain efficiency levels for each design line analyzed. In other words, each TSL will include the 14 design lines analyzed for distribution transformers, and a set of efficiency levels. Generally, the higher the TSL, the higher the efficiency level for each design line. For the NOPR, DOE examined seven TSLs for liquid-immersed distribution transformers, six TSLs for LVDT distribution transformers, and five TSLs for MVDT distribution transformers.

[10] 77 FR 32916

higher efficiency levels was a key element in adopting TSL 1. Although DOE proposed TSL 1 for LVDT distribution transformers in the NOPR, DOE adopted TSL 2 for both low-voltage and medium-voltage dry-type transformers in the final rule. With the primary argument from stakeholders against higher TSLs being concerns for small manufacturers to adopt those levels, DOE argued that TSL 2 affords small LVDT transformer manufacturers with several strategic paths to compliance: (1) Investing in mitering capability, (2) continuing to use low-capital butt-lap core designs with higher grade steels, (3) sourcing cores from third-party core manufacturers, or (4) focus on the exempt portion of the market. Compliance with the amended standards established for distribution transformers in the final rule was required as of January 1, 2016.

More recently, on September 22, 2017, DOE published a test procedure RFI to initiate a data collection process to consider whether to amend DOE's test procedure for distribution transformers. DOE published this RFI to inform DOE's 7-year review requirement specified in EPCA, which requires that DOE publish either an amendment to the test procedures or a determination that amended test procedures are not required. (42 U.S.C. 6314(a)(1)) The issues outlined in the RFI mainly concerned the degree to which the per-unit load (PUL) testing measurement accurately represents in-service distribution transformer performance, and provides test results that reflect energy efficiency, energy use, and estimated operating costs during a representative average use cycle of an in-service transformer; sampling; representations; alternative energy determination methods (AEDMs); and any additional topics that may inform DOE's decisions in a future test procedure rulemaking, including methods to reduce regulatory burden while ensuring the procedure's accuracy. DOE received several comments regarding these topics.

DOE used the comments from the test procedure RFI to inform the test procedure NOPR. On May 10, 2019, DOE published the test procedure NOPR for distribution transformers. The test procedure NOPR proposed clarifying amendments to the test procedure for distribution transformers to revise and add definitions of certain terms, to incorporate revisions based on the latest versions of relevant Institute of Electrical and Electronic Engineers (IEEE) industry standards, and to specify the basis for voluntary representations at any PUL. The proposals in the NOPR were minor revisions that do not significantly change the test procedure.

On June 18, 2019, DOE published an Early Assessment Review RFI pursuant to the six-year review requirement specified in EPCA, which requires that DOE publish either a determination that amended standards are not required or propose amended standards, and requires, if proposed amended standards are published, that DOE publish a final rule amending such standards. (42 U.S.C. 6316(a); 42 U.S.C. 6295(m)(1)). The RFI solicited data and information from the public to help DOE determine whether amended standards for distribution transformers would result in significant energy savings and whether those standards would be technologically feasible and economically justified.

Following the publication of the RFIs, DOE received several comments from stakeholders. In this preliminary analysis, DOE is addressing the comments and providing preliminary results based on draft analyses.

1.5 STRUCTURE OF THE DOCUMENT

This preliminary TSD outlines the analytical approaches used in this rulemaking. The TSD consists of 16 chapters as well as appendices.

Chapter 1 Introduction: Provides and overview of the appliance standards program and how it applies to the distribution transformers rulemaking, provides a history of DOE's action to date, and outlines the structure of this document.

Chapter 2 Analytical Framework, Comments from Interested Parties, and DOE Responses: Describes the rulemaking process step by step, summarizes comments made from interested parties during the RFI comment period, and provides DOE responses to those comments.

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

Chapter 4 Screening Analysis: Determines which technology options are viable for consideration in the engineering analysis.

Chapter 5 Engineering Analysis: Discusses the methods used for developing the relationship between increased manufacturer price and increased efficiency.

Chapter 6 Markups to Determine Equipment Price: Discusses the methods used for establishing markups for converting manufacturer prices to customer prices.

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

Chapter 8 Life-Cycle Cost and Payback Period Analyses: Discusses the economic effects of standards on individual customers and users of the equipment and compares the LCC and PBP of equipment with and without higher efficiency standards.

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

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

Chapter 11 Customer Sub-Group Analysis: Discusses the effects of standards on a subgroup of distribution transformer customers and compares the LCC and PBP of equipment with and without higher efficiency standards for these customers. This analysis will be conducted during the NOPR phase.

Chapter 12 Preliminary Manufacturer Impact Analysis: Discusses the effects of standards on the finances and profitability of manufacturers.

Chapter 13 Emissions Impact Analysis: discusses the effects of standards on emissions of carbon dioxide (CO_2), and other greenhouse gases (GHG). This analysis will be conducted during the NOPR phase.

Chapter 14 Monetization of Emissions Reduction Benefits: discusses the monetary benefits associated with the reduction in emissions due to the standards. This analysis will be conducted during the NOPR phase.

Chapter 15 Utility Impact Analysis: discusses the effects of standards and electric and gas utilities. This analysis will be conducted during the NOPR phase.

Chapter 16 Employment Impact Analysis: discusses the effects of standards on national employment. This analysis will be conducted during the NOPR phase.

Chapter 17 Regulatory Impact Analysis: Discusses the present regulatory actions as well as the impact of non-regulatory alternatives to setting energy efficiency standards. This analysis will be conducted during the NOPR phase.

1.5.1 List of 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 14 representative units, illustrating no-load losses versus manufacturer selling price (MSP); load losses versus MSP; and transformer weight versus efficiency.

App. 5B Material Price Sensitivity Engineering Results: presents scatter plots for each of the 14 representative units illustrating comparisons between the baseline prices and material price sensitivities.

App. 5C Scaling Relationships in Transformer Manufacturing: discusses the technical basis of the 0.75 scaling rule.

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. 7C Data Description and Exploratory Analysis of Industry Provided Transformer Load Data

App 7D Impact of New Data Source on Join Probability Distribution Functions

App. 8A	Uncertainty and Variability.
App. 8B	Life-Cycle Cost Sensitivity Analysis.
App. 8C	Impact on Structures Caused from Increased Transformer Size
App. 8D	Limitations on Distribution Transformer Installations.
App. 8E	Distributions Used for Discount Rates
App. 10A	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 trends.
App. 10B	Full-Fuel-Cycle Analysis, provides the methodological overview and inputs used in the Full-fuel-cycle analysis.

CHAPTER 2. ANALYTICAL FRAMEWORK, COMMENTS FROM INTERESTED PARTIES, AND DOE RESPONSES

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 2. ANALYTICAL FRAMEWORK, COMMENTS FROM INTERESTED PARTIES, AND DOE RESPONSES

2.1 INTRODUCTION

2.1.1 Overview

This chapter provides a description of the general analytical framework that DOE is using to evaluate potential standards for distribution transformers. The analytical framework is a description of the methodology, analytical tools, and relationships among the various analyses that are part of this rulemaking.

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

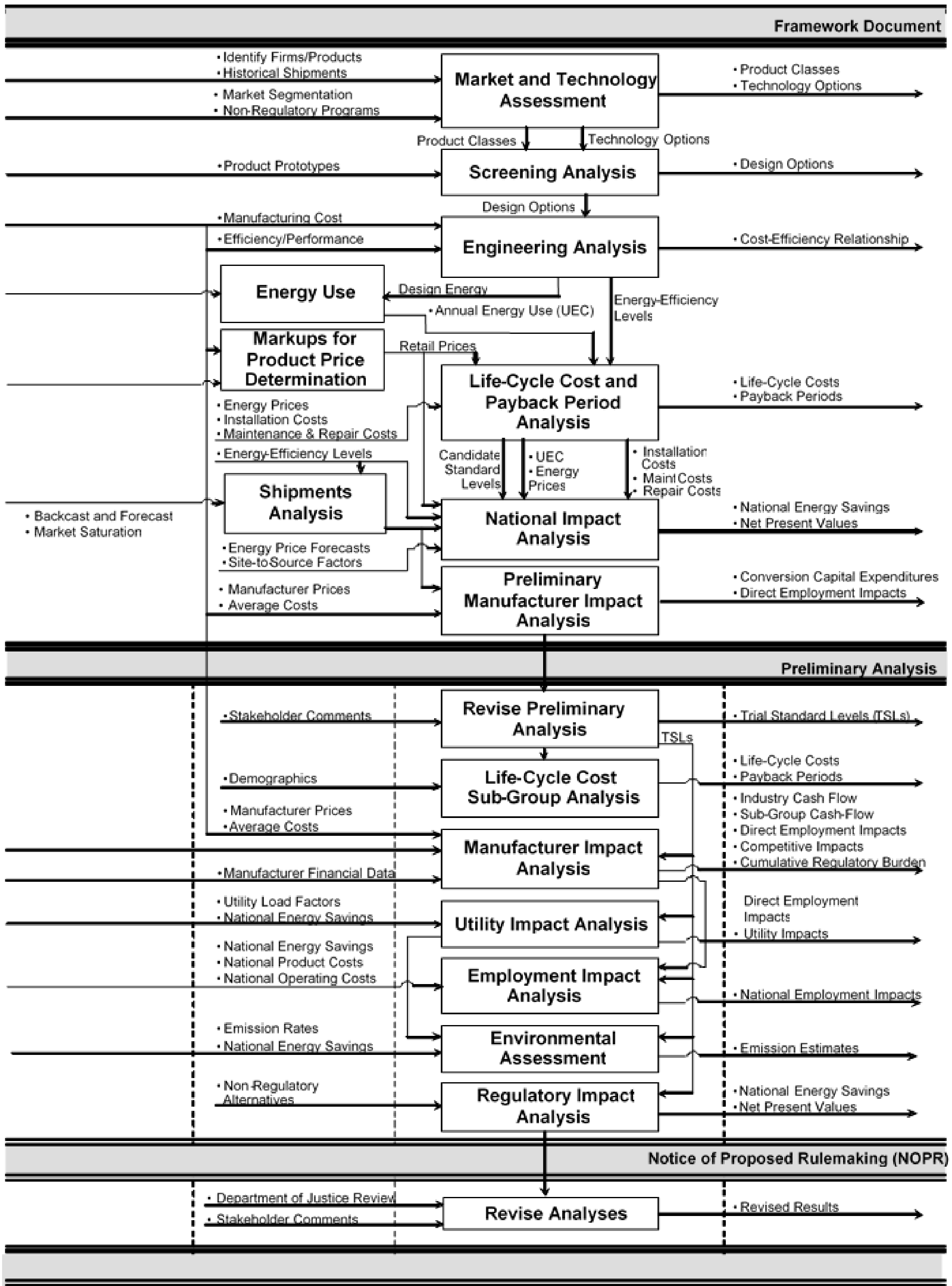


Figure 2.1.1 Flow Diagram of Analyses for the Rulemaking Process

Subsequent to the June 18, 2019, publication of the energy conservation standards request for information ("June 2019 Early Assessment RFI"), DOE received comments from interested parties regarding DOE's analytical approach. 85 FR 28239.

Table 2.1.1 June 2019 Early Assessment RFI Written Comments

Commenter(s)	Reference in this NOPR	Commenter Type
American Public Power Association	APPA	Utilities
Appliance Standards Awareness Project, American Council for an Energy-Efficient Economy, Natural Resources Defense Council	Efficiency Advocates	Policy Advocacy
Eaton Corporation	Eaton	Transformer Manufacturer
Edison Electric Institute	EEI	Utilities
ELEN-MECH. Consulting Inc	EM Consulting	Other
Hammond Power Solutions Inc.	Hammond	Transformer Manufacturer
Howard Industries Inc.	Howard	Transformer Manufacturer
HVOLT Inc.	HVOLT	Independent Consultant
Institute for Policy Integrity	IPI	Other
LakeView Metals, Inc.	LVM	Core Manufacturer
Metglas Inc.	Metglas	Steel Manufacturer
National Rural Electric Cooperatives Association	NRECA	Utilities
National Electrical Manufacturers Association	NEMA	Trade Organization
Powersmiths International Corp.	Powersmiths	Transformer Manufacturer
Schneider Electric	Schneider	Transformer Manufacturer

A parenthetical reference at the end of a comment quotation or paraphrase provides the location of the item in the public record.[1]

This chapter summarizes the key comments and describes DOE's responses. In the executive summary of the preliminary TSD, DOE identifies several issues for which DOE seeks public comment. DOE explains each of those issues in the relevant analysis sections below.

2.2 SCOPE OF COVERAGE

The current definition for a distribution transformer codified in 10 CFR part 431.192 is the following:

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.

In the June 2019 Early Assessment RFI, DOE requested comments on the current definition of distribution transformers, and whether amendments specific to the kVA range were warranted. 85 FR 28239, 28243

Several commenters recommended changes related to both the inclusion and definition of equipment currently excluded from the definition of "distribution transformer". (Schneider, No. 8 at p. 2; Hammond, No. 6 at p. 4; NEMA, No. 13 at p. 2; Eaton, No. 12 at pp. 4-5; Powersmiths, No. 3 at p. 2) These comments are discussed below.

[1] The parenthetical reference provides a reference for information located in the docket of DOE's rulemaking to develop energy conservation standards for distribution transformers. (Docket No. EERE-2019-BT-STD-0018-0013 which is maintained at *www.regulations.gov/#!docketDetail;D=EERE-2019-BT-STD-0018-0013*). The references are arranged as follows: (commenter name, comment docket ID number, page of that document).

2.2.1 General

In response to the June 2019 Early Assessment RFI, HVOLT and NRECA both commented that the current definition for distribution transformers is complete and not in need of any changes. (HVOLT, No. 2 at p. 3; NRECA, No. 15 at p. 3)

DOE interprets these comments to apply generally, including to each of the transformer varieties discussed in sections 2.2.2 through 2.2.9.

2.2.2 Autotransformers

Schneider commented that autotransformers were initially excluded from the definition of distribution transformers because autotransformers have historically had higher efficiencies than isolation (*i.e.*, non-autotransformers) distribution transformers, but that this is no longer the case. (Schneider, No. 8 at p. 2) Schneider stated that autotransformers are increasingly being marketed and used as substitutes for isolation distribution transformers in alternate energy solutions. (Schneider, No. 8 at p. 2) It recommended revising the definition of distribution transformers to only exclude "medium-voltage autotransformers." (Schneider, No. 8 at p. 3)

In the preliminary analysis, DOE has not included "low-voltage autotransformers" in its analysis of distribution transformers. DOE notes that the statutory definition of distribution transformer does not include "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, Uninterruptible Power System transformer, impedance transformer, regulating transformer, sealed and nonventilating transformer, machine tool transformer, welding transformer, grounding transformer, or testing transformer." (42 U.S.C. 6291(35)(b)(ii)) Unlike isolation distribution transformers (which have no continuous conductive path from primary to secondary windings), autotransformers do not provide galvanic isolation and thus would be unlikely to be used in at least some general purpose applications.

DOE requests comment regarding autotransformers use as substitutes for isolation distribution transformers, in particular: (1) Applications in which substitution occurs and applications for which loss of galvanic isolation would negate substitution incentive; (2) Estimated magnitude of substitution; (3) Evidence of substitution occurring; (4) Ability of autotransformers to meet current energy conservation standards; (5) Typical relative cost savings associated with substitution of an autotransformer for an isolation distribution transformer.

2.2.3 Drive (Isolation) Transformers

Schneider recommended updating the definition of drive isolation transformers to only exclude medium-voltage drive isolation transformers and low-voltage drive isolation transformers that provide more than 6-pulse inputs[2], while low-voltage drive isolation transformers with 6-pulse inputs should be subject to standards. (Schneider, No. 8 at p. 2) It claimed that this definition would also bring alignment between DOE's regulations and Natural Resources Canada ("NRCAN"). (Schneider, No. 8 at p. 2) Schneider also recommended clarifying in the definition of drive isolation transformer that the isolation is between the line and the drive, not the drive and the motor as currently written. (Schneider, No. 8 at p. 3)

Hammond commented that the current exclusion for drive isolation transformers is potentially open to abuse and it generally makes sense to increase the efficiency of some of these drive isolation transformers. It supported including "two winding drive isolation transformers" in the scope of the "distribution transformer" definition to align between DOE and NRCAN. (Hammond, No. 6 at p. 4) NEMA stated that some drive isolation transformers could be used in place of distribution transformers, but was unaware of such application occurring and therefore did not recommend such an amendment. (NEMA, No. 13 at p. 2)

As noted, the statutory definition of distribution transformer does not include 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. (42 U.S.C. 6291(35)(b)(ii)) While commenters suggested that certain "drive isolation transformers" could be used in general purpose applications, DOE does not have any data indicating, nor did any commenter suggest, that "drive isolation transformers" are currently being widely used in general purpose applications. As a result, DOE considers "drive isolation transformers" statutorily excluded on account of being designed for special purpose applications. Therefore, in this preliminary analysis, DOE has not included "drive isolation transformers" in its analysis of distribution transformers.

DOE requests comment and data regarding whether "drive isolation transformers" are being used in place of general-purpose distribution transformers, and if so, in what cases and to what degree.

If certain "drive isolation transformers" are being widely used in general purpose applications, DOE requests comment regarding the definition of "drive isolation transformers"

[2] Drive transformers may be categorized by the number of voltage "pulses" they pass to downstream drive components (e.g., rectifiers). Higher pulse counts may produce lower harmonic distortion in drive systems, which is generally desired, though possibly at the expense of reduced efficiency and greater cost.

generally and, in particular: (1) whether only transformers that supply greater-than-six-pulse power are unsuited to general-purpose applications; (2) how pulse count should be defined;

2.2.4 Sealed and Nonventilated Transformers

Eaton and NEMA both recommended DOE revise definitions for both sealed and nonventilated transformers to specify that the exclusion applies only to dry-type transformers. Eaton and NEMA state that the current definition could be interpreted to exclude a liquid-immersed transformer as a sealed or nonventilated transformer. (Eaton, No. 12 at p. 2-3; NEMA, No. 13 at p. 2) Powersmiths further stated that non-ventilated transformers should not be excluded because there are no technological reasons preventing DOE's efficiency standards from being met, adding that a more efficient transformer has less losses to dissipate, which is advantageous to a nonventilated transformer. (Powersmiths, No. 3 at p. 2)

In this preliminary analysis, DOE has not included "sealed and nonventilated transformers" in the analysis of distribution transformers because as noted the statutory definition of distribution transformer does not include 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 "sealed and nonventilating transformers." (42 U.S.C. 6291(35)(b)(ii)) Regarding comments from Eaton and NEMA as to the potential for misinterpretation of the sealed and nonventilated transformers exclusion, liquid-immersed transformers are explicitly included in the definition of what constitutes a distribution transformer. 10 CFR 431.192. For this preliminary analysis, DOE has not analyzed dry-type sealed and nonventilated transformers and has analyzed general purpose liquid-immersed distribution transformers that meet the voltage and kVA ranges of the distribution transformer definition.

DOE requests comment regarding the definition of "sealed and nonventilated transformers" generally and, in particular: (1) whether liquid-immersed should be explicitly excluded from the definition; and (2) what difference in loss sealed and nonventilated transformers typically exhibit relative to open equivalents.

2.2.5 Special-Impedance Transformers

Impedance is an electrical property that relates voltage across and current through a distribution transformer. It may be selected, among other reasons, to balance voltage drop, overvoltage tolerance, and compatibility with other elements of the local electrical distribution system. Currently, any transformer built to operate at an impedance outside of the normal impedance range for that transformer's kVA rating, given in Table 1 and Table 2 of 10 CFR

431.192 under the definition of "special-impedance transformer," is excluded from the definition of distribution transformers. 10 CFR 431.192

Eaton recommended the normal-impedance tables be updated to show the normal impedance for a range of kVA values rather than at a single kVA as currently constructed in the DOE definition. (Eaton, No. 12 at p. 3-4) DOE notes that current 10 CFR 431.192 does not specify what the normal impedance range is for distribution transformers with rated kVA values that do not appear in Tables 1 and 2 of 10 CFR 431.192 under the definition of "special-impedance transformer." 10 CFR 431.192

DOE requests comment regarding the definition of “special impedance transformer” generally and, in particular: (1) whether Eaton’s suggested revisions to list the normal impedance values as a range of kVA values rather than a single kVA value are warranted; (2) what fraction of distribution transformers currently sold are at kVA values not listed in the normal impedance value tables at 10 CFR 431.192; (3) how manufacturers are currently interpreting the normal impedance values for units with kVA values not listed in the normal impedance value tables at 10 CFR 431.192.

Eaton also recommended some changes to what impedance values would be excluded as special-impedance transformers. (Eaton, No. 12 at p. 3-4) Specifically, Eaton proposed a reduction in the range of impedance values that would be considered normal impedance ranges. *Id.*

DOE previously expressed concern that a more narrow interpretation of what is considered normal impedance ranges could “spawn a new generation of distribution transformers with impedance outside these ranges, which would not be subject to Federal efficiency standards and test procedures.” 71 FR 24972, 24978-24979 DOE’s current definition of special-impedance transformers is based on NEMA TP 2-2005. DOE is not aware of an alternative industry definition for special-impedance distribution transformers.

In the preliminary analysis, DOE used the codified impedance values for special-impedance transformers given in the definition of special-impedance transformers. 10 CFR 431.192

DOE requests comment regarding whether industry standards designate different values for special-impedance distribution transformers than those special impedance values appearing in DOE’s definition at 10 CFR 431.192.

2.2.6 Tap Range of 20 Percent or More

Currently transformers 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 are excluded from the definition of distribution transformers. 10 CFR 431.192. Eaton commented that the definition should be revised to clarify that only full kVA rated taps are eligible for exclusion. (Eaton, No. 12 at p. 4-5) Further, Eaton recommended revising the definition for calculating the tap range to be based on the lowest tap range, rather than the nominal tap range. Eaton stated that because the nominal tap range can be selected by the manufacturer, two physically identical transformers could be included in scope or excluded depending on what the manufacturer chose as the nominal voltage. (Eaton, No. 12 at p. 4-5)

EPCA explicitly lists “a transformer with multiple voltage taps the highest of which equals at least 20 percent more than the lowest” as excluded from the definition of distribution transformer. 42 U.S.C. 6291(35)(B)(i) DOE previously stated that EPCA does not specify whether the exclusion is based on computing the percentage of the voltage difference between its lowest and highest voltage taps relative to the voltage of the lower tap, or, the traditional industry understanding, of the percentage of voltage difference relative to the nominal voltage. 71 FR 24972, 24977-24978. DOE concluded that EPCA’s exclusion is best construed as reflecting the standard industry practice of being relative to the nominal voltage and adopted that definition in 10 CFR 431.192. *Id.* DOE stated that while there is some risk of manufacturers increasing their tap range to avoid coverage, the 20 percent range is relatively large and therefore that risk is reduced. *Id.*

In the preliminary analysis, DOE maintained the existing definition at 10 CFR 431.192. However, DOE recognizes the potential that a transformer could fall within or outside of the scope of standards based on the manufacturer’s selection of nominal voltage. DOE does not currently have information as to practice of tap and nominal voltage selection, or the factors that may influence manufacturer selections.

DOE requests comment regarding the definition of “tap range” generally and, in particular: (1) whether only full-power taps should count toward the exclusion; (2) what variables impact manufacturer nominal voltage choice; (3) what fraction of currently sold transformers could move into or out of scope depending on nominal voltage choice; (4) whether the industry understanding still reflects tap ranges as being relative to the nominal voltage.

2.2.7 Uninterruptible Power Supply Transformers

Powersmiths commented that DOE should explicitly exclude from the definition of “uninterruptible power supply transformers” transformers for voltage adaptation or isolation purposes that are at the input, output, or bypass of an uninterruptible power supply system. (Powersmiths, No. 3 at p. 2)

"Uninterruptible power supply transformer" is defined as 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. 10 CFR 431.192. DOE previously stated that an uninterruptable power supply transformer "is not a distribution transformer. It does not step down voltage, but rather it is a component of a power conditioning device" and it is "used as part of the electric supply system for sensitive equipment that cannot tolerate system interruptions or distortions, and counteracts such irregularities." 69 FR 45376, 45383. DOE further clarified that uninterruptable power supply transformers do not "supply power to" an uninterruptible power system, rather they are "used within" the uninterruptible power system. 72 FR 58190, 58204. This is consistent with the reference in the definition to transformers that are "within" the uninterruptible power system. 10 CFR 431.192. Distribution transformers at the input, output or bypass that are supplying power to the uninterruptible power system are not uninterruptable power supply transformers. In this preliminary analysis, consistent with the definition at 10 CFR 431.192, DOE did include in its analysis distribution transformers at the input, output or bypass that are suppling power to the uninterruptible power system but did not include those used within the uninterruptible power system.

DOE requests comment regarding: (1) Whether manufacturers are applying the definition of "uninterruptable power supply transformer" consistent with the discussion in the preceding paragraph; and; (2) Whether amendments are needed to further clarify the definition and if so, what changes are suggested.

2.2.8 Voltage Specification Convention

As stated, the definition of "distribution transformer" is based, in part, on the voltage capacity of equipment, *i.e.*, has an input voltage of 34.5 kV or less; and has an output voltage of 600 V or less. 10 CFR 431.192. Three-phase distribution transformer voltage may be described as either "line", *i.e.*, measured across two lines, or "phase", *i.e.*, measured across one line and the neutral conductor. For delta-connected[3] distribution transformers, line and phase voltages are equal. For wye-connected[4] distribution transformers, line voltage is equal to phase voltage multiplied by the square root of three.

[3] Delta connection refers to three distribution transformer terminals, each one connected to two power phases.
[4] Wye connection refers to four distribution transformer terminals, three of which are connected to one power phase and the fourth connected to all three power phases.

NEMA and Hammond recommended that DOE clarify that the input and output voltages in the definition of distribution transformers are line voltages and not the phase voltages. (Hammond, No. 6 at p. 4; NEMA, No. 13 at p. 2)

DOE has previously stated that the definition of distribution transformer applies to transformers having an output voltage of 600 volts or less, not having only an output voltage of less than 600 volts.. 78 FR 23336, 23353. For example, a three-phase transformers for which the delta connection is at or below 600 volts, but the wye connection is above 600 volts would satisfy the output criteria of the distribution transformer definition. Additionally, DOE's test procedure requires that a transformer comply with the standard when tested in the configuration that produces the greatest losses, regardless of whether that configuration alone would have placed the transformer at-large within the scope of coverage. *Id.* Similarly with input voltages, a transformer is subject to standards if either the "line" or "phase" voltages fall within the voltage limits in the definition of distribution transformers, so long as the other requirements of the definition are also met.

DOE requests comment regarding the definition of "input voltage" and "output voltage".

2.2.9 kVA Range

The current kVA range are consistent with NEMA publications in place at the time DOE adopted the range, specifically NEMA TP-1 standard. 78 FR 23336, 23352. Subsequent to the publication of the April 18, 2013 final rule establishing standards (78 FR 23336; "April 2013 Standards Final Rule"), NEMA TP-1 standard was rescinded. In this preliminary analysis, DOE relies on the kVA range as established. However, DOE is considering investigating the energy savings potential of distribution transformers that are above and below the kVA ranges in DOE's definition of distribution transformers.

DOE requests comment regarding whether the current kVA ranges of distribution transformers given at 10 CFR 431.192 aligns with what customers purchase for distribution applications in industry. Specifically, DOE requests comment and data on the quantity and efficiency of distribution transformers that are sold above 2500 kVA, with input and output voltage still within DOE's definition of distribution transformers. DOE also requests comment and data on the quantity and efficiency of distribution transformers that are sold below 10 kVA for liquid-immersed units and below 15 kVA for dry-type units, with input and output voltage that meet the voltage criteria in DOE's definition of distribution transformers.

2.3 TEST PROCEDURE

The current test procedure for measuring the energy consumption of distribution transformers is established at appendix A to subpart K of 10 CFR part 431. DOE received comment in response to the June 2019 Early Assessment RFI on elements of the test procedure for distribution transformers that also affect several of the analyses described in this TSD chapter. Accordingly, DOE provides the following discussion regarding the test procedure for distribution transformers.

On May 10, 2019, DOE published a test procedure notice of proposed rulemaking ("May 2019 TP NOPR"), in which it responded to several comments it had received regarding the test procedure per-unit load ("PUL")[5] values at which standards were to apply ("tPUL"). 84 FR 20704, 20711-20716. For this preliminary analysis, DOE is using slightly different PUL nomenclature. What was called "tPUL" in the May 2019 TP NOPR is called "standard PUL" in this preliminary analysis to emphasize that what is referred to is the PUL at which standards apply for a given equipment class, even when testing is not performed at that PUL (*e.g.*, testing at 100 percent PUL and using the equations in appendix A to calculate losses at the standard PUL). Similarly, what was called "sPUL" in the May 2019 TP NOPR is called "in-service PUL" in this preliminary analysis to reduce risk of misinterpretation of the "s" in "sPUL" meaning "standard" instead of "in-service." To summarize, this preliminary analysis will use "standard PUL" and "in-service PUL" only.

Commenters generally asserted that the current standard PUL, 50 percent for liquid-immersed and medium-voltage dry-type ("MVDT") distribution transformers and 35 percent for low-voltage dry-type ("LVDT") distribution transformers (see 10 CFR 431.196), values are greater than prevailing, current in-service PUL values experienced by distribution transformers in operation. *Id.* DOE did not propose changing the standard PUL in the May 2019 TP NOPR but did propose to allow voluntary representations at other PULs. *Id.*

In response to the June 2019 Early Assessment RFI, the Efficiency Advocates and Powersmiths commented that the current test PULs are not reflective of true operating PULs and lead to sub-optimal distribution transformer designs. They recommend lowering the test procedure PUL to a value it asserted would be more representative. (Efficiency Advocates, No. 14 at p. 4; Powersmiths, No. 3 at p. 4-5). Powersmiths stated that substantial savings could be achieved by changing the efficiency measurement such that distribution transformers are optimized for a more realistic PUL, such at 35 percent. (Powersmiths, No. 3 at p. 2)

DOE's current estimates of root-mean-square ("RMS") in-service PUL range from 27 to 32 percent for liquid-immersed distribution transformers and is 15.9 percent for low-voltage dry-type distribution transformers, as described in section 2.8. It is possible that a distribution transformer optimized to standard PUL would not be optimized at in-service PUL. Were this the

---

[5] Per-unit load ("PUL") is the actual power supplied by a distribution transformer, divided by the distribution transformer's rated capacity. It is also referred to as "percent load," "percent of nameplate-rated load," "percent of the rated load," or "per unit load level" in 10 CFR 431.192, 10 CFR 431.196 and appendix A to subpart K of 10 CFR 431. In the May 2019 TP NOPR, DOE proposed to consolidate all of these terms into a single term per-unit load. 84 FR 20704, 20708-20709

case, it is uncertain the extent to which optimization at standard PUL as opposed to in-service PUL would impact potential energy savings realized in the field.

2.3.1 Interaction of Test Metric and Capacity Related Charges

Customers of distribution transformers bear costs arising from the quantity of energy consumption ("energy charges") as well as from the energy consumption's timing in relation to overall local electrical grid demand ("capacity or demand charges"). As part of the electrical grid, distribution transformers are relatively peak coincident, meaning distribution transformers are the most highly loaded while the electricity demand of the systemwide grid is the highest, see section 2.8 and chapter 7 of this TSD. It is at these times when the cost of electricity is the most expensive to produce or procure. Similarly, any electrical losses produced from distribution transformers during these peak loading times are of high values (in terms of $/kWh).

During peak loading times, load losses account for proportionally more losses relative to non-peak operation.[6] A distribution transformer that is optimized to minimize losses at the current in-service PUL would have lower no-load losses and higher load losses (relative to a standard PUL-optimized transformer). This could create a scenario in which a distribution transformer optimized at the in-service PUL could use slightly less energy than a transformer optimized at the standard PUL. However, the timing of the losses could make the in-service PUL optimized distribution transformer notably more expensive to operate. DOE's obligation in amending test procedures is ensuring they are reasonably designed to "measure energy efficiency, energy use, water use…, or estimated annual operating costs" during a representative average use cycle. 42 U.S.C. 6293(b)(3). Distribution transformers are unique amongst covered equipment in that the timing of their losses can have a significant impact on the estimated annual operating costs.

2.3.2 Interaction of Test Metric and Load Growth Uncertainty

Any potential amendments to the standard PUL would also need to consider the potential for future load growth. Load growth has always been, and continues to be, difficult to predict, as described in section 2.8.3. DOE's LCC and NIA analyses described in chapter 8 and 10 of this TSD, respectively, have included high-load, and low-load growth sensitivity cases to explore the effect of such uncertainty. Additionally, future load growth will be influenced by trends toward electrification of both vehicles and buildings. While the timing, rate and degree of these trends are subject to uncertainty, the trends have potential to occur over short times scales relative to typical transformer operating lifetimes, *i.e.*, the load experienced by a distribution transformer may increase during the lifetime of that unit.

Selection of standard PUL has significance in the context of evaluating the costs and benefits of potential energy conservation standards. DOE cannot know in advance which standard PUL, at the end of the 30-year analysis period and with the benefit of perfect hindsight, would have maximized cost-effective energy savings. Instead, DOE must calculate the potential

[6] See section 2.9.4.2 of this chapter, and chapter 8 for details regarding capacity costs

costs and benefits of potential energy conservation standards using estimates of relevant factors such as energy cost and load growth. Over- or underestimating in-service PUL, in the context of selecting standard PUL, may mean forgoing some energy savings that would have been found cost-effective at (what would eventually be known to be) the true in-service PUL. Thus, all else held equal, cost-effective energy savings arising from energy conservation standards are likely to be higher to the extent DOE can accurately forecast in-service PUL and select standard PUL with that in-service PUL considered.

Given the possibility of over- or underestimating in-service PUL, it is important to consider whether the relative costs of erring in each direction are equivalent. The cost of optimizing distribution transformers to a PUL that underestimates load growth may exceed the cost of optimizing distribution transformers that overestimate load growth, for two reasons. First is the cost heterogeneity introduced by capacity and demand charges mentioned in section 2.3.1 and described in more detail in section 2.8. Second, because load losses grow approximately with the square of the PUL (as described in section 2.6.2.3), an efficiency percentage at a lower PUL has fewer absolute losses than an equivalent efficiency percentage at a higher PUL. Therefore, optimizing a distribution transformer to the lower PUL and then experiencing greater load growth could lead to greater losses, because the lower efficiency is being applied to a larger-than-expected volume of energy.

In the context of maximizing the possibility of cost effective energy savings, both factors discussed above favor preferring to choose standard PUL to be too high than too low.

2.3.3 Preliminary Analysis Test Metric

In this preliminary analysis DOE considers only distribution transformers that would meet the current standard, and any potential amended standards, at the current standard PUL. However, in evaluating the cost effectiveness at higher standards, DOE uses the most accurate in-service PUL and load growth estimates to calculate energy savings potential as described in section 2.8 and section 2.9. DOE also notes that the maximum technologically feasible ("max-tech") design option for every representative unit involves amorphous steel distribution transformers that are optimized for relatively low PULs (often times below 20% PUL) but still perform well at the standard PUL, as described in chapter 5 of this TSD. Therefore, any potential energy savings that could be achieved by changing the standard PUL could also be achieved by increasing the stringency of the energy conservation standards. This is described in more detail in chapters 5, 8 and 10 of the TSD.

2.4 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. As such, for the considered equipment, DOE addressed the following: (1) manufacturer market share and characteristics; (2) existing regulatory and non-regulatory equipment efficiency improvement initiatives; (3) equipment classes; and (4) trends in equipment characteristics and retail markets. This information serves as resource material throughout the rulemaking and can be found in chapter 3 of the TSD.

2.4.1 Current Equipment Classes

DOE must specify a different standard level for a type or class of product that has the same function or intended use, if DOE determines that products within such group: (A) consume a different kind of energy from that consumed by other covered products within such type (or class); or (B) have a capacity or other performance-related feature which other products within such type (or class) do not have and such feature justifies a higher or lower standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(1)) In determining whether a performance-related feature justifies a different standard for a group of products, DOE must consider such factors as the utility to the consumer of the feature and other factors DOE deems appropriate. *Id*. Any rule prescribing such a standard must include an explanation of the basis on which such higher or lower level was established. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(2))

There are eleven equipment classes used in the existing standards for distribution transformers, one of which (mining transformers) is not subject to energy conservation standards. 10 CFR 431.196. Ten of the eleven equipment classes are determined according to the following characteristics: (1) Type of transformer insulation: Liquid-immersed or dry-type, (2) Number of phases: single or three, (3) Voltage class: low or medium (for dry-type only), and (4) Basic impulse insulation level (BIL) (for MVDT only). The eleventh equipment class is for mining transformers, which is a reserved equipment class that is not currently subject to energy conservation standards. 10 CFR part 431.196(d).

Table 2.4.1 presents the eleven equipment classes within the scope of this rulemaking analysis and provides the kVA range associated with each.

Table 2.4.1 Equipment Classes for Distribution Transformers

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
EC11	Mining Transformers				

* EC = Equipment Class

In the June 2019 Early Assessment RFI, DOE requested comment generally regarding whether additional equipment classes were warranted. 84 FR 28239, 28244-28245. HVOLT, NRECA, Hammond, and NEMA generally commented that the existing equipment classes are appropriate and sufficient for the current energy conservation standards. (HVOLT, No. 2 at p. 3;

NRECA, No. 15 at p. 1; Hammond, No. 6 at p. 4; NEMA. No. 13 at p. 3) As discussed in the following paragraphs, these stakeholders commented on the potential need for additional equipment classes were DOE to consider more stringent standards.

2.4.1.1 Mining Distribution Transformers

“Mining distribution transformers” are a separate equipment class for which standards have not been established. 10 CFR 431.196(d). “Mining distribution transformer” is defined at 10 CFR 431.192 as:

> A medium-voltage dry-type distribution transformer that is built only for installation in an underground mine or surface mine, inside equipment for use in an underground mine or surface mine, on-board equipment for use in an underground mine or surface mine, or for equipment used for digging, drilling, or tunneling underground or above ground, and that has a nameplate which identifies the transformer as being for this use only.

In the April 2013 Standards Final Rule, DOE stated that it was not establishing standards for mining distribution transformers due to the unique constraints that mining distribution transformers must meet which would disadvantage them from meeting efficiency standards. 78 FR 23336, 23353-23354. DOE stated that it may consider establishing standards if mining distribution transformers are being used to circumvent energy conservation standards for distribution transformers. *Id*. In the June 2019 Early Assessment RFI, DOE requested comment on the sale, application, and definition of mining distribution transformers as well as DOE’s decision not to set standards for these distribution transformers. 84 FR 28239, 28244

HVOLT, Hammond, and NEMA commented that the current definition is adequate and complete. (HVOLT, No. 2 at p. 3; Hammond, No. 6 at p. 4; NEMA, No. 13 at p. 3) Hammond and NEMA stated that mining distribution transformers typically have tight dimensional restriction, different duty cycles and often operate at a higher PUL than traditional distribution transformers and therefore should continue to not have standards. (Hammond, No. 6 at p. 4-5; NEMA, No. 13 at p. 3) Further, NEMA stated that it is not aware of any practice of mining distribution transformers being sold outside of their intended application and Hammond stated that they are sold directly to mining equipment manufacturers. (NEMA, No. 13 at p. 3; Hammond, No. 6 at p.4)

For the preliminary analysis, DOE did not analyze standards for mining distribution transformers.

2.4.2 Additional Class-setting Factors

DOE identified several potential additional class setting factors in the June 2019 Early Assessment RFI. 84 FR 28239, 28245. These potential class setting factors are listed in Table 2.4.2.

Table 2.4.2 Potential Class Setting Factors for Distribution Transformers

Transformer Category	Description
Step-up Transformers	Transformers that increase voltage from primary to secondary (more secondary winding turns than primary winding turns).
Pole-mounted Transformers	Transformers that are mounted above-ground on poles.
Pad-mounted Transformers	Transformers that are ground mounted, specifically in a locked steel cabinet mounted on a concrete pad.
Network Transformers	Transformers that operate within a grid configuration and connect end loads to multiple distribution transformers simultaneously; often used for redundancy and in densely populated areas.
Vault-based Transformers	Transformers that have features unique to operation in a vault, which is a fully-enclosed chamber dedicated to housing the transformer and is not easily expandable.
Submersible Transformers	Transformers that are able to maintain indefinite rated operation while submerged.
Transformers with multi-voltage capacity	Transformers that are able to be reconfigured to accommodate different primary and secondary voltages, in addition to those that can provide multiple voltages simultaneously.

HVOLT, Schneider, and Hammond commented that there was no need to further divide the distribution transformer classes based on these factors. (HVOLT, No. 2 at p. 3; Schneider, No. 8 at p. 4; Hammond, No. 6 at p. 5) Several commenters stated that there is no need to create new equipment classes but with the caveat that if higher standards are adopted, it may be necessary to further subdivide equipment. These comments are discussed in more detail below.

2.4.2.1 Step-Up Transformers

For transformers generally, the term “step-up” refers to the function of a transformer providing greater output voltage than the input voltage. In reference to creating a possible equipment class for step-up transformers, stakeholders had differing opinions. HVOLT asserted that renewable energy step-up transformers are by definition not distribution transformers and should not be included in the scope of this rulemaking. (HVOLT, No. 2 at p. 3) NRECA commented that medium-voltage step-up transformers should be subject to the same requirements as all other liquid-filled distribution transformers. (NRECA, No. 15 at p. 1) Hammond commented that the other equipment specification establishes performance requirements for these renewable energy step-up transformers to meet their equipment efficiency. (Hammond, No. 6 at p. 5) DOE interprets Hammond’s comment to mean that step-up transformers in renewable energy applications are already selected on the basis of efficiency and, therefore, equipment classes for these distribution transformers are unnecessary.

The fact that a transformer is designated for step-up operation does not inherently mean that transformer is excluded from the definition of distribution transformers. Any transformer with an input and output voltages below the input and output voltage limits given in 10 CFR 431.192 would be a “distribution transformer,” provided it met the other definitional criteria, even if it were designed for step-up operation.

Most step-up transformers would by definition fall outside the scope of current energy conservation standards due to limitations on input and output voltage. The definition for distribution transformers at 10 CFR 431.192 specifies an output voltage limitation of 600 V. Step-up transformers typically have an output voltage larger than 600 V.

In certain cases, physical similarities could allow a consumer to operate step-up transformer in reverse such that it functions as a distribution transformer. DOE acknowledged there was some risk of consumers operating step-up transformers in this manner in the April 2013 Standards Final Rule. 78 FR 2336, 23354. However, commenters did not identify this as a widespread circumvention practice at the time, nor has DOE identified this in practice in the industry since. *Id*. As a result, DOE has not included step-up transformers in this preliminary analysis.

DOE requests comment regarding the possibility of manufacturers using step-up transformers in distribution transformer applications generally and, in particular: (1) what the typical efficiency is of step-up transformers currently on the market; (2) what fraction, if any, of step-up transformers currently sold are being used in traditional distribution applications; and (3) what the typical input and output specifications are for step-up transformers that could be operated in reverse in distribution transformer applications.

2.4.2.2 Pole- and Pad-Mounted Transformers

Eaton commented that under the current energy conservation standards there is no need to further subdivide equipment classes, but that if energy conservation standards are increased, it may become necessary to separate pole- and pad-mounted distribution transformers. (Eaton, No. 12 at p. 5) Eaton stated increased weight may limit increases in efficiency for pole-mounted transformers because such increases may at some point require mass pole replacement that would limit the economic justification. *Id.* Similarly, Eaton commented that the potential need to use a triplex design[7] for pad-mounted distribution transformers if efficiency increases result in too high of a ferroresonance[8] as potentially negatively impacting any economic benefit of higher standards, which Eaton claims could require a new equipment class for pad-mounted distribution transformers. (Eaton, No. 12 at p. 5) NRECA commented that because pole and pad-mounted

[7] A triplex design consists of three separate, single-phase distribution transformers that are interconnected to form one three-phase bank.
[8] Ferroresonance refers to the nonlinear resonance resulting from the interaction of capacitors and inductors which can lead to damaging high voltages in distribution transformers. Pad-mounted distribution transformers that are delta-connected are particularly susceptible to ferroresonance effects since the underground distribution cables can serve as capacitors and the iron core as an inductor.

distribution transformers serve similar applications there is no need to separate them. (NRECA, No. 15 at p. 1-2)

For the purpose of the analysis conducted for this preliminary analysis, DOE did not divide pole-mounted or pad-mounted distribution transformers into separate equipment classes. To the extent that more stringent standards would potentially increase the installation costs for such distribution transformers, DOE accounted for the increase in costs as part of the economic analysis. See section 2.9.3.

DOE requests comment and data to characterize the effect of mounting configuration on distribution transformer efficiency, weight, volume, and likelihood of introducing ferroresonance.

2.4.2.3 Network, Vault, Submersible and Subway Distribution Transformers

In the context of this preliminary analysis, DOE uses the term “vault distribution transformer” to mean a distribution transformer specifically designed for and installed in an underground, below-grade, vault. DOE estimates that these transformers represent less than 2 percent of units shipped; and are typically owned and operated by utilities serving urban populations. The vaults in which these distribution transformers are installed are typically underground concrete rooms with an access opening in the ceiling through which the transformer can be lowered for installation or replacement. Similarly, in the context of this analysis, DOE uses the term “subsurface distribution transformer” to mean a distribution transformer specifically designed and installed in a prefabricated concrete enclosure that is buried in the ground so that the installed transformer can be accessed at grade.

Both vault distribution transformers and subsurface distribution transformers may be sometimes described as “submersible” or “subway”, indicating a greater ability to tolerate exposure to or immersion in water. Both vault distribution transformers and subsurface distribution transformers may be sometimes described as “network”, indicating design for operation as part of a larger ensemble of highly interconnected transformers as would more commonly occur in dense urban areas. Any or all four terms – network, vault, submersible, subway – may apply to a given distribution transformer. For example, a “vault” distribution transformer may or may not be “submersible”. Additionally, nomenclature may vary by manufacturer and customer.

As these terms pertain to this preliminary analysis’ consideration of equipment classes for distribution transformers, the most significant attribute is degree of space constraint. Typically, there will be a size limitation for distribution transformers located within vaults, beyond which the associated installation costs will be substantial, potentially exceeding the cost of the distribution transformer. Vault expansion to accommodate a larger distribution transformer could result in costs related to excavation and reconstruction of the vault, but also costs related to closing an area to pedestrian or automotive traffic while expansion is underway. Distribution transformers outside of vaults may also face degrees of space constraint – for example, if outgrowing a concrete pad or allotted space within a chain of switchgear. Generally, however, vault-based distribution transformers could be subject to greater potential costs arising from increased volume.

NEMA commented that at current efficiency standards there is no need to further subdivide equipment classes, however, if efficiency standards are increased, vault and submersible distribution transformers should be maintained at their current efficiency standards due to size and performance constraints. (NEMA, No. 13 at p. 4) APPA and EEI commented that DOE should actively be exploring new equipment classes for network, vault, and submersible distribution transformers due to the unique operating and size constraint of these distribution transformers. (APPA, No. 16 at p. 3; EEI, No. 10 at p. 3) EEI gave the example of a replacement vault distribution transformer which, due to increased efficiency standards, can no longer fit into the existing vault space and therefore requires a significant investment to increase the size of the vault. (EEI, No. 10 at p. 3-4) APPA recommend DOE explore these limitations and if needed, separate these space constrained distribution transformers into a separate equipment class. (APPA, No. 16 at p. 3)

DOE stated in the April 2013 Standards Final Rule that there is no technical barrier that prevents network, vault-based, and submersible distribution transformers from achieving the same levels of efficiency as other liquid-immersed distribution transformers. 78 FR 23336, 23356-23357. Additional costs may be incurred when a replacement distribution transformer is larger than the original distribution transformer and does not allow for the necessary space and maintenance clearances. Rather than separate these distribution transformers into a new equipment class in the April 2013 Standards Final Rule, DOE included the additional costs for vault replacements in the LCC analysis. *Id*. These costs are not applied to network distribution transformers located outside of vaults. *Id*.

In this preliminary analysis, based on new findings, DOE examined the impacts to network and vaultdistribution transformers and addressed the potential additional costs for any required vault expansion as a LCC sensitivity as described in section 2.13.2.

DOE requests comment and data to characterize the relationship between volume and efficiency for vault distribution transformers. In particular, DOE requests comment regarding options a customer is likely to explore before incurring the cost of expanding a vault, *e.g.*, using a lower-loss steel grade, substituting copper windings for aluminum, using a less-flammable insulating fluid with lower volume and higher temperature rise.

2.4.2.4 Multi-Voltage-Capable Distribution Transformers

Eaton and NEMA both suggested multi-voltage-capable distribution transformers as an equipment class setting factor if efficiency standards increase. (Eaton, No. 12 at p. 5; NEMA, No. 13 at p. 4) Eaton stated that when the voltage values present are in non-integer ratios,[9] a portion of the coils go unused, thus reducing the space efficiency of the coils and corresponding ability of distribution transformers to achieve higher efficiencies. (Eaton, No. 12 at p. 5)

In the April 2013 Standards Final Rule, DOE acknowledged stakeholder concern that establishing a separate equipment class for dual-voltage units could create a loophole whereby a single voltage unit is more expensive than a dual-voltage unit for which one of the voltages is the same as the single voltage unit because the dual-voltage unit is subject to a less stringent standard. 78 FR 23336, 23359. This concern continues to be present for both dual- and multi-voltage distribution transformers. For this preliminary analysis, DOE did not evaluate dual- and multi-voltage capability as a separate equipment class.

DOE requests comments and data characterizing: (1) typical loss increase associated with multi-voltage distribution transformers at different voltages; (2) characteristic load loss differences for multi-voltage distribution transformers with both integer (e.g. 7200x14400) and non-integer voltage values to enable contrast; (3) how to distinguish multi-voltage distribution transformers where voltage ratings are designed to accommodate different nominal line voltages as opposed to “taps” design to fine-tune a given nominal line voltage.

2.4.2.5 Data Center Distribution Transformers

DOE has identified an additional potential class setting factor based on whether a distribution transformer is designed for use in a data center distribution center.

During negotiations that took place as part of the April 2013 Standards Final Rule, participants noted that distribution transformers designed for data centers may experience disproportionate difficulty in achieving higher efficiencies due to certain features, namely inrush current limitation, that may affect consumer utility. 78 FR 23336, 23358. DOE considered a definition and separate equipment class for “data center transformers,” but did not propose a separate equipment class for several reasons, including (1) the proposed definition listed several factors unrelated to efficiency; (2) risk of circumvention; (3) data center operators are generally

[9] For example, a primary winding low voltage configuration of 7200 V and a primary winding high voltage configuration of 14400 V represents a 2 times increase in voltage. Whereas a primary winding low voltage configuration of 7200 V and a primary winding high voltage configuration of 13200 V represents a non-integer increase in voltage leaving some portion of the coil unused.

interested in high efficiencies to reduce their electricity costs; and (4) data center operator can take steps to limit in-rush current external to the data center transformer. *Id.*

NEMA stated that with the growth of data centers, the market has shifted for LVDTs from 300 kVA distribution transformers to 750 or 1000 kVA distribution transformers. (NEMA, No. 13 at p. 6) Manufacturers commented in interviews that with the growth of cloud computing technology in the past decade, data center distribution transformers have become more prevalent and are increasingly manufactured at higher kVA values. Further, data center distribution transformers often carry unique operating patterns compared to most distribution transformers. Namely, data center distribution transformers are larger than most other LVDTs, are operated at very high loading (greater than 75 percent) for the vast majority of their lifetime, and have much shorter lifespans than other distribution transformers.

Data center distribution transformers may be designed to be more efficient than current efficiency standards require because of the value of reduced electricity costs and a reduction in cooling needed, in the data center environment. Current regulations requiring LVDTs to meet efficiency standards at 35 percent PUL may require data center distribution transformers to be optimized at lower PULs than they otherwise would. However, DOE still has the same concerns as the April 2013 Final Rule, namely that a sufficient definition does not exist that would characterize the physical features of data center transformers while eliminating the risk that establishing a data center equipment class could be a loophole for general use distribution transformers. 78 FR 23336, 23358 Therefore, for this preliminary analysis, DOE did not consider a separate equipment class for distribution transformers designed for data centers. DOE will continue evaluating the market and application of such distribution transformers to determine if consideration of a separate equipment class is warranted.

DOE requests comment and data on the physical features that distinguish data center distribution transformers from LVDTs generally, including any specific characteristics or industry definitions that could be used to establish a definition for "data center transformer."

DOE requests comment and data on the changes in the data center distribution transformer market since the April 2013 Standards Final Rule.

DOE requests comment and data on the average PUL of data center distribution transformers.

DOE requests comment and data on the typically efficiency of data center distribution transformers at their operational PUL. Including the typical specifications customers provide when requesting a data center distribution transformer.

DOE requests comment and data on the typical lifespan of a data center distribution transformer.

2.4.3 Additional Potential Class Setting Factors

2.4.3.1 Basic Impulse Level

Distribution transformers are built to carry different basic impulse level ("BIL") ratings. BIL ratings offer increased resistance to large voltage transients, for example, from lightning strikes. Due to the additional winding clearances required to achieve a higher BIL rating, high BIL distribution transformers tend to be less space efficient, leading to higher costs and be less able to achieve higher efficiencies. DOE separates medium-voltage dry-type distribution transformers into equipment classes based on BIL ratings. 10 CFR 431.196(c). In the June 2019 Early Assessment RFI, DOE requested comment on if liquid-immersed distribution transformers should also have equipment classes separated by BIL. 84 FR 28239, 28245

NEMA commented that there is currently no need to separate liquid-immersed distribution transformers into equipment classes based on their BIL rating. (NEMA, No. 13 at p. 4) NRECA and HVOLT commented that division of liquid-immersed distribution transformers based on BIL would complicate compliance for minor differences in losses. (HVOLT, No. 2 at p. 3; NRECA, No. 15 at p. 2) Eaton commented that at present efficiency levels, further equipment classes aren't needed, but commented that higher standards may require creating a new equipment class for high BIL distribution transformers. (Eaton, No. 12 at p. 6)

For the preliminary analysis, DOE has not considered additional equipment classes based on BIL rating for liquid-immersed distribution transformers.

Regarding dry-type distribution transformers, Hammond recommended DOE apply an upper limit on the BIL of 199 kV to reflect the limitations of high BIL distribution transformers and increase the scope for 3-phase dry-type distribution transformers to cover up to 7500 kVA which would align with the NRCAN regulations. (Hammond, No. 6 at p. 4)

For the preliminary analysis, DOE has not considered additional equipment classes based on BIL rating because implementing a 199 kV BIL upper limit would remove currently covered equipment from the scope of this rulemaking and only considered the current distribution transformer kVA ranges.

DOE requests data on the change in efficiency associated with higher BIL ratings for distribution transformers and the volume of dry-type distribution transformers sold with BIL ratings above 199 kV.

2.4.4 Technology Assessment

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. These technologies encompass all those DOE initially identified as technologically feasible.

Increases in distribution transformer efficiency are based on a reduction of distribution transformer losses. There are two primary varieties of loss in distribution transformers: no-load losses and load losses. No-load losses are roughly constant with PUL and exist whenever the distribution transformer is energized (*i.e.*, connected to electrical power). Load losses, by contrast, are zero at 0 percent PUL but grow quadratically with PUL.

No-load losses occur primarily in the transformer core, and for that reason the terms "no-load loss" and "core loss" are sometimes interchanged. Analogously, "winding loss" or "coil loss" is sometimes used in place of "load loss" because load loss arises chiefly in the windings. For consistency and clarity, DOE will use "no-load loss" and "load loss" generally and reserve "core loss" and "coil loss" for when those quantities expressly are meant.

Measures taken to reduce one type of loss typically increase the other type of loss. Some examples of technology options to improve efficiency include: (1) Higher grade electrical core steels, (2) different conductor types and materials, and (3) adjustments to core and coil configurations. In the June 2019 Early Assessment RFI, DOE identified and sought feedback on the applicable technologies and designs which have the potential to improve the energy efficiency of the identified equipment classes. 85 FR 28239, 28245-28246. A detailed discussion of these technologies is given in chapter 3 of the TSD and they are listed below in Table 2.4.3 and Table 2.4.4.

Table 2.4.3 Previously Considered Technology Options and Impacts of Increasing Distribution Transformer Efficiency for the April 2013 Standards Final Rule

Technology	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:			
Increase core cross-sectional area (CSA)	Lower	Higher	Higher
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:			
Decreasing core CSA	Higher	Lower	Lower
Increasing volts per turn	Higher	Lower	Lower

Table 2.4.4 Potential Additional Technology Options for Distribution Transformers

Technology
Core Deactivation
Symmetric Core
Less-flammable insulating liquid.

DOE sought comment in the June 2019 Early Assessment RFI as to whether there have been sufficient technological or market changes since the April 2013 Standards Final Rule that justify more stringent standards. 85 FR 28239, 28246.

NEMA, EEI, Hammond, Schneider, NRECA, Powersmiths, APPA, and HVOLT commented that there have not been sufficient enough technological advancements since the last rulemaking to justify increased efficiency standards. (NEMA, No. 13 at p. 5; EEI, No. 10 at p. 2; Hammond, No. 6 at p. 6; Powersmiths, No. 3 at p. 2; Schneider, No. 8 at p. 4; NRECA, No. 15 at p. 2; APPA, No. 16 at p. 2; HVOLT, No. 2 at p. 3) Powersmiths commented that any new technologies that add complexity beyond simply changing the core and coils, such as fan cooling, have failed in the market because the added maintenance and reduced reliability offset any first cost or operating cost savings. (Powersmiths, No. 3 at p. 2).

Hammond suggested that single phase dry-type distribution transformers, for which standards were not amended in the previous rulemaking, could easily achieve economically justified higher standards by using distributed gap core technology and common steel grades. (Hammond, No. 6 at p. 6) Hammond claimed it is already selling distribution transformers with efficiencies above the minimum required by DOE. *Id.* LVM commented that it is especially important for efficiency standards to increase for all dry-type distribution transformers because they are typically purchased by contractors that are more sensitive to first costs as opposed to total ownership cost. (LVM, No. 18 at p. 1)

Many commenters stated that some technology and market changes have occurred and therefore DOE proceeded with this preliminary analysis. Several commenters provided more detailed comments on the feasibility of specific technology options listed in Table 2.4.3 and Table 2.4.4, discussed below.

2.4.4.1 Core Deactivation

In the June 2019 Early Assessment RFI, DOE discussed core deactivation as a potential technology for improving efficiency. 85 FR 28239, 28246. Core deactivation technology uses a system of smaller distribution transformers to replace a single, larger distribution transformer. Core deactivation technology has a control unit constantly monitor the system's power output, and based on the efficiencies of each combination of distribution transformers for any given loading, the control unit operates the optimal number of distribution transformers to minimize energy loss. For example, three 25 kVA distribution transformers could be operated in parallel and replace a single 75 kVA distribution transformer. Because no-load losses dominate when distribution transformers are lightly loaded and because 25 kVA distribution transformers have fewer no-load losses than 75 kVA distribution transformers, the core deactivation technology could be used to shut off two 25 kVA distribution transformers and instead increase the PUL on one of the 25 kVA distribution transformers when there is low distribution transformer loading to reduce total losses.

EM Consulting described core deactivation technology as a means to control the dry-type distribution transformers installed within an electrical distribution grid of a single site (like commercial buildings). (EM Consulting, No. 9 at p. 1) It estimated return on investment for operating this program was around 3.5 years with potential energy savings of 0.75 percent of the whole building construction and removal of the need for 60 percent of dry-type distribution transformers. (EM Consulting, No. 9 at p. 1) EM Consulting referenced a study conducted in Canada that demonstrated the potential energy savings possible through power flow optimizations, like core deactivation technology. (EM Consulting, No. 9 at p. 1) Hammond commented that core deactivation has potential and asserted that the technology demonstrates that there is a much bigger efficiency gain from correctly sizing distribution transformers and optimizing power flow than just increasing standards. (Hammond, No. 6 at p. 5)

HVOLT and Powersmiths questioned whether the decrease in no-load loss with core deactivation technology would overcome the increase in load losses associated with increased loading on a single distribution transformer. (HVOLT, No. 2 at p. 3; Powersmiths, No. 3 at p. 2) NRECA and Powersmiths commented that the increased complexity of such an approach seems likely to reduce the reliability of the system in practice. (NRECA, No. 15 at p. 2; Powersmiths, No. 3 at p. 2)

In the April 2013 Standards Final Rule, DOE acknowledged that core deactivation applied to a bank of distribution transformers may save energy over a single unit. 78 FR 23336, 23360. DOE explained that each constituent distribution transformer in the distribution transformer bank must comply with the applicable energy conservation standard if it is subject to the DOE regulations. *Id.*

Based on DOE's review of the market, this technology is not widespread in industry. EM Consulting stated that the potential impact of such a concept on the Canadian Electrical Code, National Energy Code, other CSA standards, and electrical distribution grid within commercial buildings has not yet been investigated. (EM Consulting, No. 9 at p. 1) Given the uncertainty in the industry and governmental institutions regarding this technology and the lack of data in the United States, DOE has not considered the use of core deactivation technology in the analysis conducted for this preliminary analysis.

DOE seeks comment on any regulatory challenges that may be presented in implementing core deactivation or similar power flow optimization technologies. Specifically, DOE requests comment on any governmental or industrial codes that would prohibit implementation of these technologies.

NEMA stated that future energy saving opportunities lie in system level optimizations, such as core deactivation technology. (NEMA, No. 13 at p. 5) NEMA cautioned that any modification to the method of calculating efficiency for distribution transformers in a way that would place increased value on no-load losses would be contrary to the goals and benefits of core deactivation practices. (NEMA, No. 13 at p. 4)

For this preliminary analysis, DOE has not proposed changes to the calculations of efficiency as stated in section 2.3.

2.4.4.2 Symmetric Core

In the April 2013 Standards Final Rule, DOE identified several companies that were exploring three-phase distribution transformers with symmetric cores- those in which each leg of the distribution transformer is identically connected to the other two. 78 FR 23336, 23360. These symmetric cores use a continuously wound core with 120-degree radial symmetry, resulting in a triangularly shaped core when viewed from above. DOE stated that while symmetric core technology may offer a lower-cost path to higher efficiency, DOE was unable to secure sufficiently robust cost, performance, or reliability data for an energy conservation standard. 78 FR 23336, 23361-23362. Therefore DOE did not include symmetric core designs in the previous rulemaking. *Id.*

DOE requested further data on symmetric core design in the June 2019 Early Assessment RFI. 84 FR 28239, 28246-28247 DOE did not receive any data or any comments related to the feasibility of symmetric core analysis. Further, through conversations with manufacturers, DOE has learned that while the technology still exists and has some potential to improve energy efficiency, manufacturers stated there were insufficient benefits to overcome the manufacturing and maintenance challenges of the technology. While symmetric core technology may have theoretical advantages, DOE does not have sufficient data to include it in this preliminary analysis.

2.4.4.3 Less-Flammable Liquid-Immersed Distribution Transformers

DOE requested comment on its analysis of less-flammable insulating liquid technology for liquid-immersed distribution transformers in the June 2019 Early Assessment RFI. 84 FR 28239, 28246. These distribution transformers use an insulating fluid with a higher flash point than traditional mineral oil and can therefore reduce the risk of fire or explosion in situations where traditional liquid-immersed distribution transformers would be of concern. DOE explained that it previously concluded there were no efficiency disadvantages to using these less-flammable insulating liquid and it may in fact have efficiency advantages. 78 FR 23336, 23355. NRECA agreed with DOE's position that less-flammable insulating liquid are a safety improvement that can be used in place of mineral oil with no adverse impacts aside from higher costs. (NRECA, No. 15 at p. 2)

For this preliminary analysis, DOE did not specifically investigate less-flammable liquid-immersed distribution transformers. DOE did not receive any comments suggesting manufacturers using less-flammable liquid-immersed distribution transformers would have increased difficulty meeting efficiency standards. Further, manufacturer comments in interviews suggested that less-flammable liquid-immersed distribution transformers are generally not seen as a replacement for applications where dry-type distribution transformers would be used. Rather, it is used as a safety improvement in traditional mineral oil filled liquid-immersed applications.

DOE is aware of industry efforts to use the increased thermal protections associated with less-flammable liquid-immersed distribution transformers as a means of increasing the capacity of the distribution transformer without increasing the size[10]. Based on DOE's current review of the market, this is not currently a widespread practice.

DOE requests comment and data regarding less-flammable liquid immersed distribution transformers, including the effects that increased thermal protection may have on DOE's reference temperature rise when evaluating transformer efficiency.

[10] IEEE Transformer Committee, "Discussion of New Dual Nameplate kVA for Distribution Transformers," Fall 2020. https://grouper.ieee.org/groups/transformers/subcommittees/distr/EnergyEfficiency/F20-DOETaskForce-DualkVA-Traut.pdf

DOE requests comment and data on the difference in kVA capacity that can be achieved by allowing less-flammable liquid immersed distribution transformers to operate at greater design temperature rise values.

DOE requests comment and data regarding the prevalence of less-flammable liquid-immersed distributions transformers. In particular, how commonly they are substituted for traditional liquid-immersed distribution transformers of greater kVA rating and how commonly they are substituted for traditional dry-type distribution transformer applications.

2.4.5 Electrical Steel Technology and Market Assessment

The main material choices that impact the efficiency of distribution transformers are the materials used for the transformer windings and the material used for the transformer core. For transformer windings, two base materials are commonly used in industry, aluminum and copper. Using copper windings decreases the resistivity of the windings and therefore reduces the load losses of the transformer. The choice between aluminum and copper windings often comes down to the relative price between the two, both of which are materials in the larger commodity market.

Distribution transformer cores are constructed from a specialty kind of steel known as electrical steel. Electrical steel is an iron alloy which incorporates a small percentage of silicon to enhance its magnetic properties, including increasing the magnetic permeability of the material and reducing the iron losses associated with magnetizing that steel. Electrical steel is typically produced in thin laminations which are then sliced and either wound or stacked in the core of a distribution transformer. Broadly, electrical steel can be categorized into conventional electrical steel and amorphous steel. These categorizations are discussed more in depth in TSD chapter 3.

In the past decade, the electrical steel market has been the subject of trade disputes and tariff actions[11]. In the April 2013 Standards Final Rule, DOE noted that “the potential for significant disruption in the steel supply market at higher efficiency levels was a key element” in deciding the final energy efficiency standard level. 78 FR 23336, 23383. Amongst DOE’s concerns were that only one global supplier of amorphous steel existed and a lack of suppliers of high-efficient grain-oriented electrical steels. *Id.*

[11] *See e.g.*, Grain-Oriented Electrical Steel from Germany, Japan, and Poland, Inv. Nos. 731-TA-1233, 1234, and 1236, USITC PUB. 4491 September 2014.

In the June 2019 Early Assessment RFI DOE requested comment on the quality, capacity, and market conditions of both amorphous and grain-oriented electrical steel. 84 FR 28239, 28247.

Metglas commented that presently there is only one domestic producer of conventional steels and one domestic producer of amorphous steels. (Metglas, No. 11 at p. 5) It stated that higher efficiency levels are now warranted given that the amorphous steel market has gotten more competitive, with the addition of several Chinese producers of amorphous steel since the last rulemaking, and given that amorphous steel is especially advantageous at real world loading conditions. (Metglas, No. 11 at p. 1-2) The Efficiency Advocates commented that DOE's investigation of efficiency levels above the current standard for the April 2013 Standards Final Rule demonstrated a positive NPV and were only not set higher due to concerns over the steel market. (Efficiency Advocates, No. 14 at p. 2-3) Several commenters gave more specific comments on both amorphous steel and conventional electrical steel, discussed in more detail below.

2.4.5.1 Amorphous Steel

Amorphous steel is a type of electrical steel that is produced by rapidly cooling molten alloy such that crystals do not form. The resulting product is thinner than conventional electric steel and has lower core losses as compared to conventional electrical steel, but reaches magnetic saturation at a lower flux density than conventional electrical steels. In the previous rulemaking, amorphous designs were used in the max-tech designs. 78 FR 23336, 23402-23407. However, commenters expressed concern over the fact that there was only one global supplier of amorphous, which lacked the capacity to supply the entire industry, the increased size of amorphous distribution transformers relative to conventional electrical steel, and the quality of the amorphous product to consistently produce quality distribution transformer cores. 78 FR 23336, 23381-23386.

Amorphous Steel Technology Assessment

DOE stated in the June 2019 Early Assessment RFI based on its preliminary review of the market, the brittleness, stacking factor, and flux density of amorphous steel from China has improved and these companies have increased their amorphous steel width offerings to better match the U.S. market. 84 FR 28239, 28247. DOE requested comment on the current state of amorphous steel quality. *Id.*

NEMA stated that minor improvements have been made but insufficient for the entire industry to rely on amorphous material as there remains concerns with the quality of certain amorphous steel imports. (NEMA, No. 13 at p. 6) NEMA stated that it is not aware of any future improvement in quality. *Id.*

Eaton and LVM commented that amorphous steel has seen a reduction in brittleness, an increased stacking factor and an increased flux density since the last rulemaking. (Eaton, No. 12 at p. 7; LVM, No. 18 at p. 1) Metglas commented that it now offers a next generation amorphous steel with improved ductility, lamination factor and flux density while Chinese competitors have also improved their products, sufficient for meeting max-tech from the previous rulemaking. (Metglas, No. 11 at p. 4-5) Metglas also claims that within the next five years, it expects incremental improvements in core loss, thickness optimization, and strip widths. (Metglas, No. 11 at p. 5) LVM added that amorphous cores, in addition to being higher efficiency than conventional steel, have the same cost or are cheaper to convert to a finished core as compared to conventional steels. (LVM, No. 18 at p. 1)

DOE has identified two types of amorphous steel as possible technology options for inclusion in distribution transformers. The first technology option DOE has designated as “am” and is identical to the “SA1” material that was included in the April 2013 Standards Final Rule. This material is now offered by multiple suppliers from several countries as described below and therefore some of the concerns over the lack of suppliers should be alleviated. DOE also is aware of a second type of amorphous steel designated in this preliminary analysis as “hibam” or “high-permeability amorphous steel.” DOE is only aware of one manufacturer of this high-permeability amorphous steel.[12] Based on discussion with distribution transformer manufacturers and DOE’s research, the high-permeability amorphous steel is slightly thicker and while it offers similar core loss properties at identical flux to the traditional amorphous steel, it is able to operate at a higher flux density. This gives manufacturers increased flexibility when designing distribution transformer and can allow them to reduce the size of the amorphous cores. These technology abbreviations and technology descriptions are included in Table 2.4.5 and discussed in further detail in TSD chapter 3.

Table 2.4.5 Potential New Amorphous Steel Options for Distribution Transformers

DOE Designator in Design Options	Technology
am	Traditional Amorphous Steel
hibam	High-Permeability Amorphous Steel

DOE requests comment and data on the quality, including stacking factor, core loss data, and operating flux density of the different amorphous steels available on the market.

Amorphous Steel Market Assessment

In the June 2019 Early Assessment RFI, DOE stated that it had preliminarily identified at least six companies with amorphous steel mills either in production or at some stage of development and requested comment and data regarding the barriers to entry for producers of amorphous steel, their respective production capacities, and the quality of amorphous steel. 84 FR 28239, 28247.

[12] DOE is aware of marketing for another derivative of the hibam material that uses mechanical scribing to further reduce core losses but does not have sufficient data on this derivative or any details on whether it is commercially available at this time.

Metglas commented that it is the only current producer of amorphous steel in the United States, however, there is current production in Japan and China along with amorphous capacity in Germany and South Korea. (Metglas, No. 11 at p. 2) LVM commented that there are at least four major foreign amorphous steel producers currently with capacity and two additional producers coming on-line soon. (LVM, No. 18 at p. 1) Metglas stated distribution transformer manufacturers have been slow to adopt the technology. (Metglas, No. 11 at p. 2)

Eaton stated that amorphous steel production requires a different production technology than conventional steel and the capital cost associated with that technology represents a barrier for conventional electrical steel manufacturers to enter the amorphous market. (Eaton, No. 12 at p. 6) Eaton asserted that investment in amorphous steel production would "cannibalize" conventional electrical steel manufacturers existing product offering and reduce the equipment utilization of existing equipment. (Eaton, No. 12 at p. 6)

In addition to capital barriers for production of amorphous steel, NEMA identified changes in the manufacturing process needed for producing amorphous cores as another barrier in the adoption of amorphous steel in distribution transformers. (NEMA, No. 13 at p. 6) NEMA further claimed, only a subset of manufacturers have the expertise to achieve the potential benefits. *Id.*

In the June 2019 Early Assessment RFI, DOE estimated that the current global capacity for amorphous steel was about 190,000 tonnes. Metglas agreed with DOE's estimate of capacity and stated that Metglas could further expand capacity if there was additional market demand. (Metglas, No. 11 at p. 3)

Several stakeholders identified a rapid growth in the availability of amorphous materials from China in recent years. Metglas commented that China has added significantly more amorphous steel capacity. (Metglas, No. 11 at p. 2) NEMA stated that prior to tariffs amorphous core manufacturers were using companies other than the single company initially identified in the April 2013 Standards Final Rule for 50 percent of their production. (NEMA, No. 13 at p. 5)

Both NEMA and Howard maintained concern over the availability of amorphous materials. (Howard, No. 19 at p. 2; NEMA, No. 13 at p. 5) NEMA commented that Chinese capacity is rising but questioned the extent to which that capacity was serving the U.S. market. Further, NEMA stated U.S.-China trade relationships could impact the future availability of Chinese amorphous steel. (NEMA, No. 13 at p. 6) NRECA asserted that without multiple domestic suppliers of amorphous steel, it would be irresponsible to propose standards that require its use. (NRECA, No. 15 at p. 2)

While a review of the market identifies several distribution transformer manufacturers advertising the ability to produce amorphous cores, amorphous steel currently makes up only a small fraction of the domestic distribution transformer market. Metglas commented that currently amorphous steel only has about 4 percent market penetration, representing fewer than 4,000 tonnes[13], in the U.S. (Metglas, No. 11 at p. 3)

---

[13] A tonne is equivalent to 1,000 kg, also referred to as a "metric ton." The spelling "tonne" distinguishes from a "short ton" of 2,000 lbs, which is more commonly spelled "ton."

In this preliminary analysis, DOE did not apply any capacity constraints on the number of amorphous distribution transformers that could be selected because amorphous capacity is currently much greater than amorphous steel demand and there are several suppliers of amorphous steel. If a new efficiency standard were selected that requires more amorphous than the current capacity of amorphous cores, there would be additional costs to add or convert manufacturing lines which would be accounted for in the manufacturer impact analysis, see section 2.12.

DOE requests comment and data on the global capacity of amorphous steel and how much of that capacity is available to the U.S. market.

DOE requests comment and data on the cost and time frame to add additional amorphous capacity.

DOE requests comment and data on the global capacity of amorphous core production and how much of that capacity is available to the U.S. market.

DOE requests comment and data on the cost and time frame to add additional amorphous core production capacity.

2.4.5.2 Conventional Electrical Steel

Conventional electrical steel can be further categorized into non-oriented electrical steel and grain-oriented electrical steel. Non-oriented electrical steel does not control for crystal orientation and therefore has similar magnetic properties in all directions. This is useful for some applications, such as in electric motors, however, is no longer commonly used in distribution transformers due to its lower efficiency. Grain-oriented electrical steel, by contrast, is processed with tight control over its crystal orientation such that its magnetic flux density is increased in the direction of the grain-orientation. This single-directional flow is well suited for distribution transformer applications and therefore grain-oriented electrical steel has become the dominant core technology in the manufacturing of distribution transformers.

Conventional Electrical Steel Technology Assessment

In the June 2019 Early Assessment RFI, DOE stated that it is aware of a proliferation of a more advanced grain-oriented electrical steel throughout the distribution transformer industry known as high-permeability grain-oriented electrical steel. 84 FR 28239, 28247. High-permeability grain-oriented electrical steel is able to operate at higher magnetic induction than conventional grain-oriented electrical steel and typically has lower core losses at identical induction levels. The performance of grain-oriented steels can be further enhanced by introducing local strain on the surface of the steels, through a process known as domain-refinement, such that the core losses are reduced. This process is typically performed with a high temperature laser, however the core loss benefits provided by this laser treatment do not survive the high-temperature annealing process necessary to relieve stresses in wound core distribution transformer designs. Newer domain-refinement technologies utilize mechanical scribing or chemical etching to create heat-proof, permanently domain-refined steels, the core loss benefits of which do survive the high temperature annealing.

Several commenters agreed that high-permeability steels have become more widespread throughout the distribution transformer industry. LVM commented that the performance of grain-oriented steels has dramatically improved and high-permeability grain-oriented steels are much more widely available than they were during the previous rulemaking, claiming the current supply of electrical steel exceed demand. (LVM, No. 18 at p. 1) HVOLT commented that new alloys with improved magnetic characteristics and lower core losses are available and believes they will eventually be the future of the industry. (HVOLT, No. 2 at p. 4) Eaton commented that since the last rulemaking, there has been a significant shift toward higher grade core materials, including both high-permeability laser and permanent domain-refined steels and amorphous steel. (Eaton, No. 12 at p. 6) The Efficiency Advocates commented that there have been significant changes in the steel market and encouraged DOE to investigate new amorphous and grain-oriented steels. (Efficiency Advocates, No. 14 at p. 3)

With the increase in high-permeability electrical steels, described above, the steel industry has largely shifted away from the traditional “M” grade designators. Distribution transformer manufacturers often still use M designators when referencing steels, however, DOE did not observe a consensus in industry as to what the M grade designates. “M3” for example was used in the previous DOE rulemaking to describe a conventional, grain-oriented electrical steel that was 0.23 mm thick. In conversations with manufacturer, “M3” was used to reference any steel with a 0.23 mm thickness by some manufacturers and by other manufacturers to reference any steel with similar loss performance as the “traditional” M3 steel regardless of thickness.

Steel manufacturers have largely adopted a system for high-permeability steels that includes the steels thickness, a brand specific designator, followed by the guaranteed core losses of that steel in W/kg at 1.7 Tesla (“T”) and 50 Hz. For example, if Steel Company X offers a high-permeability grain-oriented steel that is 0.23 mm thick with a guaranteed core loss of 90 W/kg at 1.7 T and 50 Hz, it would be represented as “23SCX090.” The “23” represents 0.23 mm thickness, the “SCX” is a specific brand designator from Steel Company X, and “090” represents the core losses. In the U.S., power is delivered at 60 Hz and the flux density can vary based on distribution transformer design, so the core losses reported in the steel name is not identical to the performance in the distribution transformer, however, it generally is a good indicator of the relative performance of different steels.

DOE has identified numerous conventional steels as possible technology options for inclusion in distribution transformers, including conventional grain-oriented electrical steel, high-permeability grain-oriented electrical steel, high-permeability laser domain-refined electrical steel, and high-permeability permanently domain-refined electrical steel. Further, each of these subcategories of grain-oriented electrical steels are offered in a variety of thicknesses and guaranteed core loss values. While DOE has seen some industry standards that provide a naming convention for distinguishing between conventional grain-oriented, high-permeability grain-oriented, and domain-refined high-permeability grain-oriented steels, DOE is not aware of an industry naming convention that further separates the heat-proof domain-refined steels from the non-heat-proof laser domain-refined steels. Therefore, DOE has identified the steels used in its analysis using the traditional M-grades for conventional grain-oriented electrical steel and a steel thickness, type, and losses designator for high-permeability steels. These steel type designators are described further in Table 2.4.6.

Table 2.4.6 Conventional Steel Type Designators for Distribution Transformers

DOE Steel Type Designator in Design Options	Technology
M-Grades	Conventional (not high-permeability) Electrical Steel
hib	High-Permeability Grain-Oriented Electrical Steel
dr	Non-Heat Proof, Laser Domain-Refined, High-Permeability Grain-Oriented Electrical Steel
pdr	Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Electrical Steel

DOE requests comment on the naming convention used in this preliminary analysis.

Based on conversations with manufacturers, it appears that the industry has largely settled on the 0.23 mm thickness steel as the predominant steel thickness. Thinner steels are generally considered harder to work and thicker steels have higher losses. DOE used input from industry and the brochures of several of the major grain-oriented electrical steel producers to identify materials for inclusion in its analysis. In general, there is a diverse offering of similarly performing electrical steels in the global market. DOE has listed the electrical steels considered in this analysis, in Table 2.4.7.

Table 2.4.7 Potential New Conventional Steel Options for Distribution Transformers[14]

DOE Designator in Design Options	Technology
Conventional Grain-Oriented Electrical Steel	
M6	0.35 mm thickness, Conventional Grain-Oriented Steel
M5	0.30 mm thickness, Conventional Grain-Oriented Steel
M4	0.27 mm thickness, Conventional Grain-Oriented Steel
M3	0.23 mm thickness, Conventional Grain-Oriented Steel
M2	0.18 mm thickness, Conventional Grain-Oriented Steel
High-Permeability Grain-Oriented Electrical Steel	
23hib090	0.23 mm thickness, High-Permeability Grain-Oriented Steels
23pdr085	0.23 mm thickness, Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Steels
23dr080	0.23 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
23pdr075	0.23 mm thickness, Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Steels
23dr075	0.23 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
20dr070	0.20 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels

DOE requests data and comment on the performance of the conventional steels shown in Table 2.4.7 and if there are any better performing steels available on the market

DOE requests comment on the substitutability of the steels shown in Table 2.4.7. Specifically, DOE requests comment on the technical limitations of substituting any one of the lower loss steels for any one of the higher loss steels for any given distribution transformer design

Conventional Electrical Steel Market Assessment

In the April 2013 Standards Final Rule, DOE had concerns about availability of some of the higher performing conventional steels. Specifically, DOE excluded M3 and permanently domain-refined wound core designs from its LVDT final analysis and excluded permanently domain-refined steel from its base case efficiency options. 78 FR 23336, 23366-23377. DOE

[14] DOE analyzed some distribution transformer designs using non-oriented electrical steel but their efficiencies were below current DOE standards and therefore they are not included as possible design options.

requested comment in the June 2019 Early Assessment RFI regarding whether the same capacity concerns still exist regarding M3 steel in the LVDT market. 84 FR 28239, 28247.

NEMA commented in response to the June 2019 Early Assessment RFI that supplies of higher quality steels should be sufficient for LVDTs because the same steels are typically used in MVDTs but cautioned that the higher quality steels are more expensive. (NEMA, No. 13 at p. 6-7) HVOLT added that most LVDT manufacturers are using M3 conventional grain-oriented steel today. (HVOLT, No. 2 at p. 4)

Regarding the conventional steel supply more generally, NEMA stated that supplier diversity is very important for distribution transformer manufacturers and commented that there is currently only one domestic producer of grain-oriented electrical steel. (NEMA, No. 13 at p. 5) NEMA further stated that the current trade environment has made it difficult for distribution transformer manufacturers to source electrical steels. (NEMA, No. 13 at p. 7) LVM and NEMA commented that the only domestic producer of grain-oriented electrical steels does not have capacity of high-grade steel to serve the entire U.S. market, meaning the U.S. would be dependent on foreign electrical steel producers. (LVM, No. 18 at p. 1; NEMA, No. 13 at p. 6)

In this preliminary analysis, DOE has not applied any capacity limitations in its analysis of conventional steel design options because stakeholders have not provided any data indicating where capacity limits would be applicable. In cases where fewer steel suppliers offer a grade of conventional steel, this would be reflected in higher prices, however, DOE did not explicitly limit the quantity of a given steel that can be selected in their analysis.

DOE requests comment on the availability of the steel shown in Table 2.4.7 and if any steels are offered only in limited capacity or from an insufficient number of suppliers.

DOE requests comment and data regarding the performance of steels predominantly serving the large power transformer market and the ability for those steels to also serve the distribution transformer market.

DOE requests comment and data regarding the costs for steelmakers to add or convert capacity from lower performing steels to higher performing steels.

2.5 SCREENING ANALYSIS

The screening analysis (chapter 4 of the TSD) examines various technologies as to:

(i) Technological feasibility. Technologies incorporated in commercial products or in working prototypes will be considered technologically feasible.

(ii) Practicability to manufacture, install and service. If mass production of a technology under consideration for use in commercially-available products (or equipment) 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.

(iii) Adverse Impacts on Product Utility or Product Availability.

(iv) Adverse Impacts on Health or Safety.

(v) Unique-Pathway Proprietary Technologies. If a design option utilizes proprietary technology that represents a unique pathway to achieving a given efficiency level, that technology will not be considered further.

10 CFR 431.4; 10 CFR part 430 subpart C appendix A section 6(c)(3)(i)-(v).

As described in section 2.4.4, DOE develops an initial list of efficiency-enhancement options from the technologies identified as technologically feasible in the technology assessment. Then DOE reviews the list to determine if these options are practicable to manufacture, install, and service, would adversely affect equipment utility or availability, or would have adverse impacts on health and safety. In addition, DOE removed from the list technology options that lack energy consumption data as well as technology options whose energy consumption could not be adequately measured by existing DOE test procedures. In the engineering analysis, DOE further considers efficiency enhancement options that it did not screen out in the screening analysis.

2.5.1 Technology Options Screened Out

In the market and technology assessment (chapter 3 of the TSD), DOE developed an initial list of technologies expected to have the potential to improve the energy efficiency of distribution transformers. In the screening analysis, DOE screened out technologies based on the criteria discussed above. The list of remaining technologies becomes one of the key inputs to the engineering analysis (discussed subsequently). For reasons explained below, DOE screened out a number of technologies, listed in Table 2.5.1.

Table 2.5.1 Screened out Technology Options

Technology	Eliminating in 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.

In the June 2019 Early Assessment RFI, DOE requested comment on the screening criteria it applied and how the criteria relate to the various options included in the technology assessment section above. 84 FR 28239, 28248 DOE further requested comment on if any of the technology options listed in Table 2.5.1 would continue to be screened out. *Id.*

NRECA agreed with DOE's current screening criteria, stating that if a technology is not currently incorporated into products, it should be excluded. (NRECA, No. 15 at p. 2) It commented that it takes time to develop experience with new technologies and rushing them can lead to safety concerns. *Id.* NEMA commented that the screening criteria are sufficient. (NEMA, No. 13 at p. 7) Other stakeholders commented that nothing has changed to justify screening in any of the technologies listed in Table 2.5.1. (NRECA, No. 15 at p. 2; Hammond, No. 6 at p. 6; NEMA, No. 13 at p. 7)

EEI and APPA stated that solid-state distribution transformers could eventually represent a technological improvement that requires DOE to update efficiency standards, however, solid-state distribution transformers are still currently being researched and are not currently available in the marketplace. (APPA, No. 16 at p. 2; EEI, No. 10 at p. 2-3) The Efficiency Advocates asserted that solid-state distribution transformers are beginning to enter the market and offer higher efficiency and a range of additional features. (Efficiency Advocates, No. 14 at p. 3-4) The Efficiency Advocates recommended DOE investigate the impact of electric vehicles on the future price and availability of solid-state distribution transformers as they use similar technologies and the proliferation of electric vehicles could advance the availability of solid-state distribution transformers. (Efficiency Advocates, No. 14 at p. 4)

HVOLT commented that silver has similar properties to copper but is extremely cost prohibitive and should be screened out. (HVOLT, No. 2 at p. 4) HVOLT also commented that high temperature superconductors require significant infrastructure to remove heat which makes them unfeasible and therefore should be screened out. (HVOLT, No. 2 at p. 4) HVOLT further commented that amorphous core material used in stacked cores would result in excessive eddy losses which would decrease the performance and make the cost and performance unattractive. (HVOLT, No. 2 at p. 4) HVOLT stated that high temperature insulating materials are finding some uses in solid and liquid insulation and may be important in high overload applications. (HVOLT, No. 2 at p. 4)

DOE did not receive any data indicating that any of these technologies should be screened in and therefore has maintained them as screened out in this preliminary analysis.

2.5.2 Technology Options Considered Further in Analysis

After screening out technologies in accordance with the provisions set forth in 10 CFR part 430, subpart C, appendix A, (6)(c)(3) and (7)(b), as referenced by 10 CFR 431.4, DOE considers using a combination of core steels, winding materials, and core configurations as viable "design options" for improving energy efficiency of the distribution transformers under this preliminary analysis. The market and technology assessment (chapter 3 of the TSD) provides a detailed description of these design options. These design options will be considered by DOE in the engineering analysis and are listed in chapter 5 of the TSD.

For more details on how DOE developed the technology options and the process for screening these options and the design options that DOE is considering, see the market and technology assessment (chapter 3 of the TSD) and the screening analysis (chapter 4 of the TSD).

2.6 ENGINEERING ANALYSIS

The purpose of the engineering analysis (chapter 5 of the TSD) is to establish the relationship between the efficiency and cost of distribution transformers. There are two elements to consider in the engineering analysis; the selection of efficiency levels to analyze (*i.e.*, the "efficiency analysis") and the determination of product cost at each efficiency level (*i.e.,* the "cost analysis"). In determining the performance of higher-efficiency equipment, DOE considers technologies and design option combinations not eliminated by the screening analysis. For the analyzed equipment class, DOE estimates the baseline cost, as well as the incremental cost for the equipment at efficiency levels above the baseline. The output of the engineering analysis is a set of cost-efficiency "curves" that are used in downstream analyses.

Chapter 5 discusses the equipment classes DOE analyzed, the representative baseline units, the incremental efficiency levels, the methodology DOE used to develop the manufacturing production costs, the cost-efficiency relationship, and the impact of efficiency improvements on the considered equipment.

2.6.1 Representative Units Analyzed

Distribution transformers are divided into different equipment classes categorized by physical characteristics that affect equipment efficiency. Key physical characteristics are: (1) capacity (kVA rating), (2) voltage rating, (3) phase count, (4) insulation category (*e.g.*, "liquid-immersed"), and (5) BIL rating. As described in Section 2.4.1, DOE analyzed ten equipment classes. Furthermore, as discussed, distribution transformer energy use varies with capacity, so DOE analyzed several capacity ratings for each equipment class to assess how energy use varies with capacity.

Because it is impractical to conduct detailed engineering analysis at every kVA rating, DOE conducts detailed modeling on 14 “representative units” (“RUs”). These RUs are selected both to represent the more common designs found in the market and to include a variety of design specifications to enable generalization of the results. The representative units do not map to equipment classes 1:1. For example, Equipment Class 1 (liquid-immersed; single-phase) includes 3 RUs. These RUs differentiate the distribution transformers by insulation type (Liquid-immersed or dry-type), number of phases (single or three), and primary insulation levels for medium-voltage dry-type distribution transformers (three different BIL levels). These RUs are unchanged from the April 2013 Standards Final Rule. 78 FR 23336, 23364. These representative units are listed in Table 2.6.1.

Table 2.6.1 Equipment Classes and Representative Units

EC	RU	Description	Representative Unit
1	1	Liquid-immersed, single-phase, rectangular tank	50 kVA, 65 ºC, single-phase, 60Hz, 14400V primary, 240/120V secondary, rectangular tank, 95kV BIL.
1	2	Liquid-immersed, single-phase, round tank	25 kVA, 65 ºC, single-phase, 60Hz, 14400V primary, 120/240V secondary, round tank, 125kV BIL.
1	3	Liquid-immersed, single-phase	500 kVA, 65 ºC, single-phase, 60Hz, 14400V primary, 277V secondary, round tank, 150kV BIL.
2	4	Liquid-immersed, three-phase	150 kVA, 65 ºC, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary, 95kV BIL.
2	5	Liquid-immersed, three-phase	1500 kVA, 65 ºC, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary, 125kV BIL.
3	6	Dry-type, low-voltage, single-phase	25 kVA, 150 ºC, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL
4	7	Dry-type, low-voltage, three-phase	75 kVA, 150 ºC, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL
4	8	Dry-type, low-voltage, three-phase	300 kVA, 150 ºC, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL
6	9	Dry-type, medium-voltage, three-phase, 20-45 kV BIL	300 kVA, 150 ºC, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
6	10	Dry-type, medium-voltage, three-phase, 20-45 kV BIL	1500 kVA, 150 ºC, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
8	11	Dry-type, medium-voltage, three-phase, 46-95 kV BIL	300 kVA, 150 ºC, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
8	12	Dry-type, medium-voltage, three-phase, 46-95 kV BIL	1500 kVA, 150 ºC, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
10	13	Dry-type, medium-voltage, three-phase, 96-150 kV BIL	300 kVA, 150 ºC, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL
10	14	Dry-type, medium-voltage, three-phase, 96-150 kV BIL	2000 kVA, 150 ºC, three-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL

2.6.2 Efficiency Analysis

DOE typically uses one of two approaches to develop energy efficiency levels for the engineering analysis: (1) relying on observed efficiency levels in the market (*i.e.*, the efficiency-level approach), or (2) determining the incremental efficiency improvements associated with incorporating specific design options to a baseline model (*i.e.*, the design-option approach). Using the efficiency-level approach, the efficiency levels established for the analysis are determined based on the market distribution of existing products (in other words, based on the range of efficiencies and efficiency level "clusters" that already exist on the market). Using the design option approach, the efficiency levels established for the analysis are determined through detailed engineering calculations and/or computer simulations of the efficiency improvements from implementing specific design options that have been identified in the technology assessment. DOE may also rely on a combination of these two approaches. For example, the efficiency-level approach (based on actual products on the market) may be extended using the design option approach to interpolate to define "gap fill" levels (to bridge large gaps between other identified efficiency levels) and/or to extrapolate to the max-tech level (particularly in cases where the max-tech level exceeds the maximum efficiency level currently available on the market).

In this rulemaking, DOE is adopting an incremental efficiency (design-option) approach. This approach allows DOE to investigate the wide range of design option combinations, including varying the core steel material, primary winding material, secondary winding material, and core manufacturing technique. This is consistent with the approach that was conducted during the April 2013 Standards Final Rule. 78 FR 23336, 23364.

In the April 2013 Standards Final Rule, for each representative unit given in Table 2.6.1, DOE generated hundreds of unique designs by contracting with Optimized Program Services, Inc. ("OPS"), a software company specializing in distribution transformer design. The OPS software used two primary inputs: (1) a design option combination, which included core steel grade, primary and secondary conductor material, and core configuration, and (2) a loss valuation. DOE examined numerous design option combinations for each representative unit. The OPS software generated 518 designs for each design option combination based on unique loss valuation combinations. Taking the loss value combinations, known in the industry as A and B values and representing the commercial consumer's present value of future no-load and load losses in a distribution transformer, respectively, the OPS software sought to generate the minimum total ownership cost ("TOC"). TOC can be calculated using the equation below.

$$TOC = Transformer\ Purchase\ Price + A * [No\ Load\ Losses] + B * [Load\ Losses]$$

From the OPS software, DOE received thousands of different distribution transformer designs. DOE used these distribution transformer designs to create a manufacturer selling price ("MSP"). The MSP was generated by applying material costs, labor estimates, and various mark-ups to each design given from OPS. The engineering result included hundreds of unique distribution transformer designs, spanning a range of efficiencies and MSPs. DOE used this data as the cost versus efficiency relationship for each representative unit. DOE then extrapolated this relationship, generated for each representative unit, to all of the other, unanalyzed, kVA ratings within that same equipment class.

In the June 2019 Early Assessment RFI, DOE requested comment as to whether the depth and breadth of the engineering design simulations should be increased and whether this method of conducting the engineering analysis should be maintained in any potential future rulemaking.

84 FR 28239, 28249 Further, DOE requested comment on if there were any better methods for establishing a cost efficiency relationship, such as using publicly owned utility bid responses. *Id.*

NEMA and Hammond generally commented that the method used for the April 2013 Standards Final Rule was sufficient and should be maintained as it gave reasonable results that were generally agreed upon. (NEMA, No. 13 at p. 8; Hammond, No. 6 at p. 6) NEMA commented that the depth was adequate but the breadth could be improved by choosing representative units of more commonly built units. (NEMA, No. 13 at p. 8) HVOLT stated that the modeled results were generally good and established reasonably close consensus but certain assumptions did disadvantage certain manufacturers. (HVOLT, No. 2 at p. 4) HVOLT commented that most of the manufacturers have had their own software and have found greater accuracy for their manufacturing systems than the generalized results from OPS, but that DOE's approach continues to be an effective way of analyzing any future direction. (HVOLT, No. 2 at p. 4)

DOE notes that in selection of representative units it is not trying to select only the most commonly built units. Rather, these RUs are selected both to represent some of the more common designs found in the market and units that would allow for more accurate generalization and scaling within an equipment class.

DOE requests data and comment on what more commonly built units would better serve as representative units to increase the breadth of the analysis.

Eaton commented that when the current energy conservation standards went into effect in 2016 some larger distribution transformers with low voltage secondaries either required copper windings or went extinct. (Eaton, No. 12 at p. 8) Eaton recommended that DOE include additional high-current designs and space limited designs in its engineering analysis, specifically: 1) Single-phase pole-mount units with 2400 X 7970, dual-voltage primary & 120/240-volt secondary, in 25kVA, 50kVA and 167kVA; 2) three-phase pad-mount unit with 2400/4160Y/2400X7200/12470Y/2400-volt primary and 480Y/277-volt secondary in 2500kVA; and 3) three-phase pad-mount unit with 2400-volt primary and 208Y/120-volt secondary in 1500kVA in the engineering analysis. (Eaton, No. 12 at p. 8)

Eaton also commented that the results were thorough, but the use of a Monte Carlo simulation and probabilistic distributions made it overly complex to verify. (Eaton, No. 12 at p. 8) Eaton stated it would not be opposed to the same or similar approach but recommend a simplified version be introduced so that the public can verify. *Id.*

DOE notes that the engineering analysis does not use Monte Carlo simulations. The engineering analysis produces the cost-efficiency curve that is then used in downstream analyses (*e.g.*, LCC and PBP). A Monte Carlo simulation is used for the customer-selection model, which also uses the cost-efficiency curve and is designed to simulate customers purchases. DOE presents the results of the engineering analysis in TSD chapter 5.

DOE did not have sufficient data to support whether the addition of the units proposed by Eaton would best increase the representativeness of the analysis. Given that it is impractical for DOE to analyze every design possibility, DOE wants to ensure that any additional representative unit sufficiently increases the representativeness of DOE's analysis. In this preliminary analysis, DOE has maintained the representative units presented above. However, DOE is considering adding additional representative unit(s) if data supports that the current analysis does not sufficiently represent certain distribution transformers.

DOE requests comment and data explaining why some of the representative units mentioned by stakeholders are disadvantaged in meeting efficiency standards.

DOE requests data demonstrating the difference in efficiency for these disadvantaged designs compared to designs that existed prior to the implementation of the most recent efficiency standards.

DOE requests data on the increase in cost associated with meeting efficiency standards for the units mentioned by stakeholders. Or if they cannot be built to meet efficiency standards, DOE requests data demonstrating the maximum efficiency they can achieve.

DOE requests information, and associated data, as to other distribution transformer designs that may be disadvantaged by potential higher standards.

NRECA commented that the approach fails to consider the differences in PUL for various applications or of different size units. (NRECA No. 15 at p. 2) NRECA stated that a 50 percent PUL loading level results in greater total load losses when loaded, because manufacturers are forced to optimize their designs at 50 percent PUL and therefore the goal of reducing distribution transformer losses is circumvented by a lack of flexibility. (NRECA No. 15 at p. 2) NRECA recommended DOE incorporate a TOC method in its costing method. (NRECA, No. 15 at p. 2)

DOE's engineering analysis is not limited to distribution transformers designs optimized only for 50 percent PUL. Rather, the OPS model optimizes each design option combination over an array of A and B values. The efficiency of each distribution transformer is then calculated at 50 percent PUL for liquid-immersed and MVDTs and 35 percent for LVDTs and used to generate a cost-efficiency curve. In the LCC and NIA analyses, however, loading over the life of the distribution transformer is not assumed to be constant at the standard PUL, as explained in section 2.8. Therefore, the energy savings for distribution transformers operated at the full range of real world loading are accounted for and a subset of distribution transformers are selected using the TOC method. Further, while manufacturers may often optimize distribution transformers to have the lowest first-cost, the energy conservation standards do not require manufacturers to optimize distribution transformers at the standard PUL.

In the June 2019 Early Assessment RFI, DOE sought comment on the possibility of using publicly-owned utilities distribution transformer bid data to provide representative design and pricing data. 84 FR 28239, 28249. Eaton commented that the public utility bid data would be a good method for cross checking the cost assumptions and DOE could possibly use multipliers if its numbers are significantly varied from the utility data. (Eaton, No. 12 at p. 8)

For this preliminary analysis, DOE collected publicly available bid data for a variety of distribution transformers. However, this data was limited in its ability to generate a cost-efficiency curve for a variety of reasons. First, the available data identified by DOE was limited to liquid-immersed distribution transformers. Second, there was a lot of variability in the voltages of identically sized distribution transformers, which makes comparisons between similarly sized models difficult. Third, most distribution transformers were near the DOE efficiency minimum while the amorphous designed distribution transformers were significantly above the DOE efficiency minimum, not allowing for a true cost-efficiency curve. Fourth, much of the publicly available bid data was prior to 2016, when the last rulemaking went into effect. Lastly, there was a large variability in price for distribution transformers at every efficiency. This is likely driven by different constraints of the utility or limitations of the individual bidder. DOE has presented a sampling of its public utility data as compared to the OPS modeling in TSD chapter 5.

For this preliminary analysis, DOE maintained the existing distribution transformer designs from the previous rulemaking and updated the material prices to get an updated manufacturer selling price. DOE did not include any new designs for the high-permeability amorphous steel and rather updated the existing traditional amorphous steel designs to current prices. While there are some design-flexibility advantages to using the high-permeability amorphous steel, it is only available from a single supplier. Several manufacturers stated in interviews that they would be hesitant to rely on a single supplier of amorphous material for any higher volume unit. Further, the high-permeability amorphous steel can be integrated into manufacturers existing amorphous designs, with minimal changes. Therefore, DOE's amorphous transformer designs included in this preliminary analysis represent efficiencies that can be met with either traditional amorphous steel or high-permeability amorphous steel.

DOE requests comment on its assumption that any design with the high-permeability amorphous steel could be used in existing amorphous designs with minimal changes.

DOE also adapted models of conventional steel to reflect some of the lower loss steels that have come into the market since the previous rulemaking. This was conducted by assuming the core steel of a previous model was directly swapped for a new lower loss core steel while the core size, operating flux density, and all other relevant attributes remained the same. For example, if a design in the last rulemaking used 23dr080 steel at an operating flux of 1.54 T, DOE generated the results for 23dr075 by multiplying the no-load losses of the 23dr080 design by that ratio of core losses of 23dr075 steel at 1.54 T over the core losses of 23dr080 steel at 1.54 T. DOE received interview feedback from manufacturers that this would likely generate a valid design, assuming the core density and stacking factor are not changed, although it may not be the true optimal design given that a lower loss steel allows more flexibility in the load losses. Because DOE's designs cover a wide range of A and B values, this method will generate sufficiently accurate estimates to include in the engineering analysis. The method for generating these results is explained in more detail in TSD chapter 5.

DOE requests comment on calculating efficiency for a direct swap of core steel on existing distribution transformer designs. Specifically, DOE requests data demonstrating how the distribution transformer efficiency changes if a direct swap is made for a lower loss steel of identical thickness and with identical operating flux.

2.6.2.1 Core Construction Technique

Similar to the April 2013 Standards Final Rule, DOE examined a number of core construction techniques in its engineering analysis, including butt-lapping, full mitering, step-lap mitering, and distributed gap wound construction. *See* 78 FR 23336, 23362. The method of core construction changes the core losses by adding additional stresses in the distribution transformer core where losses can occur. These additional stresses are accounted for in the OPS software by multiplying the raw core losses (watt of loss per pound of steel at a particular set of conditions) by a core destruction factor that varies depending on the core construction technique. The exact core constructions investigated for each design option combination are described in TSD chapter 5.

Distributed gap wound cores typically need a high-temperature annealing process to relieve some of the stresses associated with the core winding process. As a result of this high-temperature annealing, laser-scribed domain-refined steels lose the core loss benefits of the domain-refinement. As such, DOE has not included any laser-scribed domain-refined steels in any distributed gap wound core design option combinations.

DOE requests comment on its decision to not include any laser-scribed domain-refined steels in distributed gap wound core designs.

In the April 2013 Standards Final Rule, DOE was concerned that for some small manufacturers, the costs of expensive equipment required for core mitering was prohibitive. *Id.* Therefore, the previous analysis of single-phase LVDTs centered on butt-lapped designs. In interviews with manufacturers conducted for this preliminary analysis, DOE was told that the distribution transformer market has had a large increase in the capacity of distribution transformer core manufacturers. As such, fewer small distribution transformer manufacturers still produce cores and more commonly purchase them from dedicated core manufacturers. Given the increase in dedicated core manufacturers, DOE does not expect core construction technologies to disproportionally impact small businesses.

DOE request comment on its assumptions that core construction techniques no-longer place a disproportionate burden on small manufacturers.

2.6.2.2 Baseline and Higher-Level Efficiency

To perform engineering analysis, DOE generally selects a baseline model as a reference point for each equipment class, and measures changes resulting from potential energy conservation standards against the baseline. The baseline model in each equipment class represents the characteristics of an equipment typical of that class (*e.g.*, capacity). Generally, a baseline model is one that just meets current energy conservation standards, or, if no standards are in place, the baseline is typically the most common or least efficient unit on the market.

With baseline established, DOE selects functionally similar units at higher efficiency levels within the equipment class. These higher-efficiency units are selected to, as much as possible, maintain the important attributes of the baseline unit and vary mostly in cost and efficiency. By subtracting the cost of a higher-efficiency unit from the cost of a baseline unit, DOE estimates the incremental purchase cost to a distribution transformer buyer.

DOE's analysis for distribution transformers generally relies on this baseline approach. However, instead of selecting a single unit for each efficiency level, DOE selects a set of units to reflect that different distribution transformer purchasers may not choose distribution transformers with identical characteristics because of differences in applications. The mechanics of the customer choice model are described further in 2.9.2.

2.6.2.3 Load Loss Scaling

DOE energy conservations standards apply only at a single PUL for a given distribution transformer equipment class (50 percent for liquid-immersed distribution transformers and medium voltage dry-type distribution transformers and 35 percent for low-voltage dry-type distribution transformers). 10 CFR 431.196. However, distribution transformers exhibit varying efficiency with varying PUL. Distribution transformer losses are separated into "load losses" and "no-load losses", the former of which is approximated as a quadratic function of PUL, *i.e.*, load losses grow in proportion to the square of PUL. 78 FR 23336, 23372. In practice, efficiency deviates slightly from this assumption for a variety of reasons, such as differences in temperature rise. In the June 2019 Early Assessment RFI, DOE requested comment on the validity of using the quadratic formula to calculate efficiency at differing PULs and whether there is a more accurate formula to approximate the distribution transformer load losses. 84 FR 28234, 28252.

NEMA and HVOLT commented that the quadratic formula of modeling load losses as a function of PUL is the most accurate method without analyzing specific designs. (HVOLT, No. 2 at p. 4-5; NEMA, No. 13 at p. 9) NEMA commented that the current reference temperatures in the test procedure are approximations of the expected winding temperature so any variation from the quadratic formula would have to be design specific. (NEMA, No. 13 at p. 9) HVOLT gave the example of high temperature insulation systems leading to a higher ratio of load loss to no-load loss. (HVOLT, NO. 2 at p. 5)

NRECA commented that it encourages the most accurate means of determining load losses as a function of PUL, but did not provide an alternative to the DOE approach. (NRECA, No. 15 at p. 2) DOE did not receive any comments that the quadratic approximation of load losses was unrepresentative. DOE is maintaining its use of the quadratic relationship between load losses and PUL when analyzing distribution transformer efficiency across the range of real world PULs.

DOE request any comment regarding approximating load losses as a quadratic function of PUL.

Distribution transformers achieve peak efficiency at the PUL for which no-load loss equals load loss. This relationship tends to improve the relative cost-effectiveness of amorphous- and conventional steel-based designs, respectively, at lower and higher PULs. HVOLT commented that conventional steels are the best option for future distribution transformers, as electric vehicles and increased air conditioning will increase distribution transformer loading. (HVOLT, No. 2 at p. 3-4) Metglas asserted that amorphous is the best material for future distribution transformers because present loading is relatively low and not projected to increase, meaning a lot of energy could be saved by using amorphous distribution transformers. (Metglas, No. 11 at p. 6-7)

DOE’s test procedure requires that liquid-immersed distribution transformers and MVDTs be tested at 50 percent PUL and LVDTs at 35 percent PUL. 10 CFR 431.193 and appendix A to subpart K of 10 CFR 431. Therefore, these PULs were used as the basis for calculating efficiency in the cost-efficiency curve, for which both amorphous and conventional steels were included as design options.

DOE’s engineering analysis is not limited to distribution transformers designs optimized only for the standard PUL. Rather, the OPS model optimizes each design option combination over an array of A and B values. The efficiency of each distribution transformer is then calculated at the standard PUL and used to generate a cost-efficiency curve. In the downstream analyses, DOE does not assume that distribution transformers are operated solely at the standard

PUL, rather energy savings are evaluated at the best available loading data over the typical energy use cycle, as described in section 2.8.

2.6.3 Cost Analysis

The cost analysis portion of the Engineering Analysis is conducted using one or a combination of cost approaches. The selection of cost approach depends on a suite of factors, including the availability and reliability of public information, characteristics of the regulated product, availability and timeliness of purchasing the equipment on the market. The cost approaches are summarized as follows:

- Physical teardowns: Under this approach, DOE physically dismantles a commercially available product, component-by-component, to develop a detailed bill of materials for the product.

- Catalog teardowns: In lieu of physically deconstructing a product, DOE identifies each component using parts diagrams (available from manufacturer websites or appliance repair websites, for example) to develop the bill of materials for the product.

- Price surveys: If neither a physical nor catalog teardown is feasible (for example, for tightly integrated products such as fluorescent lamps, which are infeasible to disassemble and for which parts diagrams are unavailable) or cost-prohibitive and otherwise impractical (*e.g*. large commercial boilers), DOE conducts price surveys using publicly available pricing data published on major online retailer websites and/or by soliciting prices from distributors and other commercial channels.

In the present case, DOE conducted the analysis by applying materials prices to the distribution transformer designs modeled by OPS. The primary material costs in distribution transformers come from electrical steel used for the core and the aluminum or copper conductor used for the primary and secondary winding. DOE sought to account for the frequent fluctuation in price of these commodities by examining prices over multiple years.

For the April 2013 Standards Final Rule, DOE used its estimates of both 2010-year and 2011-year prices as references cases for results. 78 FR 23336, 23367. To construct material prices estimates, DOE spoke with manufacturers, suppliers, and industry experts to determine the prices paid for each raw material used in a distribution transformer. DOE developed an average materials price for the year based on the price a medium-to-large manufacturer would pay. *Id.* DOE used a similar approach for this preliminary analysis as described in the following paragraphs.

2.6.3.1 Conductor Prices

Aluminum and copper are the materials used as conductors. The prices of aluminum and copper conductor are strongly correlated to the price of the underlying commodities, which are tracked in various public indices. In the June 2019 Early Assessment RFI, DOE requested comment on using public indices, such as those published by the London Metal Exchange (LME) and CME Group (*e.g.* COMEX) to extrapolate material prices from 2010 to the present. 84 FR 28239, 28249-28250.

Eaton commented that these price indices do not present reliable data to be used for cost extrapolation purposes and DOE should use manufacturer interviews. (Eaton, No. 12 at p. 9) Eaton further commented that the application of tariffs has increased the price of aluminum. (Eaton, No. 12 at p. 9) DOE has learned based on feedback from manufacturers, despite a 10 percent *ad valorem* tariff on aluminum produced from certain countries, manufacturers are able to partially mitigate the impact of these tariffs by changing suppliers.

In this preliminary analysis, DOE used a combination of cost extrapolation from the public indexes and calibrated the data based on information received in manufacturer interviews. Further, DOE assumed that the 10 percent aluminum tariff would be partially offset by, *e.g.*, changes in sourcing, suppliers' absorbing some cost, and reduced demand for aluminum throughout the market. Therefore, in the base-case price scenario, DOE assumed a price increase of 7.5 percent as a result of aluminum tariffs. DOE also included price sensitivity scenarios in TSD chapter 5, which include modeling of a market without tariffs on aluminum.

Table 2.6.2 Estimated Conductor Prices

Item and description	2020 Price ($/lb)
Copper wire, formvar, round #10-20	$3.89
Copper wire, enameled, round #7-10	$4.03
Copper wire, enameled, rectangular sizes	$4.22
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped	$3.89
Copper strip, thickness range 0.02-0.045	$3.75
Copper strip, thickness range 0.030-0.060	$3.59
Aluminum wire, formvar, round #9-17	$3.75
Aluminum wire, formvar, round #7-10	$3.20
Aluminum wire, rectangular #<7	$3.49
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped	$2.27
Aluminum strip, thickness range 0.02-0.045	$1.67
Aluminum strip, thickness range 0.045-0.080	$1.70

DOE requests feedback and data on the costs of conductor material presented in Table 2.6.2.

2.6.3.2 Electrical Steel Prices

The other major material cost for distribution transformers is the cost of the core electrical steel. While the price of steel often moves with the commodity market, electrical steel tends to move separately and independently. The prices of electrical steels have experienced more variation following the implementation of tariffs. In the June 2019 Early Assessment RFI, DOE requested comment on the electrical steel prices to be used in its analysis. 84 FR 28239, 28249-28251.

Regarding amorphous steel pricing, Metglas commented that there is greater capacity in the U.S., Canada, and Mexico to convert amorphous steel strip into amorphous cores. (Metglas, No. 11 at p. 5) Metglas estimated that North American amorphous core capacity could support 20 percent of the liquid-filled distribution transformer market. (Metglas, No. 11 at p. 5) Metglas further commented that bringing on core making capacity is relatively straight forward and inexpensive compared to increasing amorphous steel production capacity. (Metglas, No. 11 at p. 5) Further, Metglas commented that amorphous steel cores have decreased in cost since the previous rulemaking, and a stronger domestic demand would further decrease costs. (Metglas, No. 11 at p. 5)

For the April 2013 Standards Final Rule, amorphous steel was assumed to be purchased as a finished core, rather than purchased as raw steel. This meant the cost of the amorphous steel was higher than simple electrical steel, however, DOE included fewer processing adders, such as core steel scrap, since the cores were assumed to be purchased as a finished product. 78 FR 23336, 23368. While amorphous core production may have increased since the last rulemaking, Metglas commented that amorphous core capacity could only support 20 percent of the liquid-filled distribution transformer market, indicating that most manufacturers are not producing their own amorphous cores, as they typically do with conventional steel. Therefore, for this preliminary analysis, DOE maintained the assumption that amorphous steel was being purchased as a finished core.

DOE requests comment and data on its assumption that the majority of manufacturers are sourcing their amorphous cores rather than producing their own.

DOE requests comment and data on the cost differential to source amorphous cores compared to producing amorphous cores in-house.

Regarding conventional electrical steel, Eaton commented that the price of domestically produced electrical steel increased as a result of a manufacturer exiting the electrical steel market and with the implementation of tariffs. Further, it stated that the prices for high-permeability and laser scribed domain-refined electrical steel are much higher in the U.S. than in the global market. (Eaton, No. 12 at p. 9) Hammond commented that steel prices fluctuate with supply and demand and with the application of tariffs, however, there hasn't been a significant difference in relative prices between steel grades since 2013. (Hammond, No. 6 at p. 7)

DOE did not receive specific price data from stakeholders and instead relied on a combination of data from a well-known steel market data vendor along with manufacturer interviews to derive a price for the various steel grades used in DOE's design option combinations in this preliminary analysis.

While there is a 25 percent *ad valorem* tariff on all raw imported electrical steel, manufacturer responses in DOE interviews and in comments to a Department of Commerce investigation of imparts of laminations for stacked cores (BIS-2020-0015), manufacturers have indicated an ability to partially mitigate the impact of tariffs by either purchasing finished cores, off-shoring their own core manufacturing, or purchasing domestically produced electrical steel[15].

DOE assumed that the 25 percent steel tariff would be partially mitigated via changes in sourcing and purchasing. Therefore, in the base-case price scenario, DOE assumed the tariffs increased the cost of all electrical steels by 18.8 percent. DOE also conducted price sensitivity scenarios, shown in the TSD, to model a scenario without tariffs and a scenario with an expansion of the tariffs to apply to cores and laminations.

Table 2.6.3 Estimated Electrical Steel Material Prices

Item and description	2020 Price ($/lb)
Grain-Oriented Electrical Steel	
M6	$1.13
M5	$1.10
M4	$1.11
M3	$1.30
M2	$1.43
High-Permeability Grain-Oriented Electrical Steel	
23hib090	$1.28
23pdr085 (permanently domain-refined)	$1.52
23dr080 (domain-refined)	$1.42
23pdr075 (permanently domain-refined)	$1.69
23dr075 (domain-refined)	$1.69
20dr070 (domain-refined)	$1.71
Amorphous Electrical Steel (Finished Cores)	
am	$1.84

[15] AK Steel, BIS-2020-0015-0075. Available at: https://www.regulations.gov/document/BIS-2020-0015-0075

DOE requests feedback and data on the costs of electrical steels presented in Table 2.6.3. Further, DOE request data on the relative costs between lower-loss grades of steel.

DOE requests feedback and data on the relative costs increases associated with the application electrical steel tariffs.

2.6.3.3 Scrap Factors

DOE applies a variety of core assembly mark-ups depending on the type of steel used in each design option combination. These markups and a description of what they account for are given in Table 2.6.4.

Table 2.6.4 Scrap Factor Markups

Item and description	Mark-up
Handling and Slitting (%): 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 distribution transformer (*e.g.*, lengths of wire too short to wind, trimmed core steel).	1.50%
Scrap Factor (%): 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 distribution transformer (*e.g.*, lengths of wire too short to wind, trimmed core steel).	1.00%
Amorphous Scrap Factor (%): 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.	1.50%
Mitered Scrap Factor: An additional scrap markup applies to steel used in mitered or cruciform cores.	4.00%

For conventional electrical steel, DOE applied the scrap factor and handling and slitting factor to the material costs of the core steel, winding and insulation. In cases where a mitered core is used, DOE also applied a mitered scrap factor on the core steel costs, in addition to the scrap factor and handing and slitting factor. If an amorphous core is used, DOE assumed that the core was sourced rather than manufactured in-house. Therefore, DOE applied an amorphous scrap factor that accounts for any scrap associated with the breakage of prefabricated cores along with any scrap associated with assembling the windings or insulation on the cores.

DOE requests comment on the appropriateness and magnitude of the mark-ups applied as material scrap in this preliminary analysis.

In the April 2013 Standards Final Rule, DOE had incorporated a core steel processing adder to account for the increased costs and retooling costs associated with mitered designs of low- and medium-voltage dry-type distribution transformers in response to manufacturer comment. 78 FR 23336, 23368. In this preliminary analysis, DOE maintains the cost adders (between $0.10 or $0.31 per pound, depending on type of mitering and representative unit) associated with mitering, which is described in TSD chapter 5.

DOE requests comment on any increased costs associated with mitered, and specifically step-lap miter, core designs as compared to wound core and butt-lap cores. Further, DOE requests feedback on the appropriateness and magnitude of any processing mark-ups applied for mitered core designs.

2.6.3.4 Other Material Prices

In the June 2019 Early Assessment RFI, DOE requested comment on the cost of a variety of additional materials used in distribution transformer construction. 84 FR 28239, 28249-28251. DOE did not receive any comment on these materials and therefore relied on using inflators and feedback from manufacturer interviews to determine the cost.

Table 2.6.5 Estimated Other Material Prices

Item and description	2020 Price ($/lb)
Nomex Insulation	$28.24
Kraft insulating paper with diamond adhesive	$2.08
Mineral oil	$2.76
Impregnation	$25.99
Winding Combs	$14.22
Tank/Enclosure Steel	$0.35

DOE also included costs for various additional components, including terminals, bus-bar, mounting frames, bracing, nameplate, duct spacers, and other misc. hardware. These costs differed slightly for each representative unit and are listed in chapter 5 of the TSD.

DOE requests feedback and data on the cost of the other materials used in distribution transformer manufacturing listed in Table 2.6.5.

2.6.4 Markups

2.6.4.1 Factory Overhead

In the April 2013 Standards Final Rule, DOE used a factory overhead markup to account for all indirect costs associated with production, indirect materials and energy used (*e.g.*, annealing furnaces), taxes, and insurance. 78 FR 23336, 23368. DOE applied the cost of factory overhead by applying a 12.5 percent markup to direct material production costs. This mark-up was applied prior to the nonproduction markup. Id.

In this preliminary analysis, DOE maintained a factory overhead markup of 12.5 percent on the direct material production costs and applied that markup prior to the nonproduction markup.

DOE requests comment on the magnitude and application of the factory overhead mark-up.

2.6.4.2 Labor

Labor costs are an important aspect of the cost of manufacturing a distribution transformer. Chapter 5 of the TSD provides detail as to how the number of labor hours were derived for each distribution transformer design. The number of labor hours for each design was then multiplied by the fully-burdened labor cost per hour to give a total labor cost for each design. In the June 2019 Early Assessment RFI , DOE requested comment as to how the price of labor used to construct distribution transformers has changed since the April 2013 Standards Final Rule. 84 FR 28239, 28251.

Eaton recommended updating the references relied on by DOE to a more current U.S. Census Bureau report and consulting with several manufacturers to obtain precise labor data. (Eaton, No. 12 at p. 9) Hammond commented that labor costs have increased in line with inflation. (Hammond, No. 6 at p. 7)

DOE initially updated its labor rate estimate based on U.S. Bureau of Labor Statistics rates for North American Industry Classification System ("NAICS")[16] Code 335311- "Power, Distribution, and Specialty Transformer Manufacturing" production employee hourly rates and applied mark-ups for indirect production, overhead, fringe, assembly labor up-time, and a nonproduction mark-up to get a fully burdened cost of labor. DOE then presented this value to

---

[16] NAICS is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy.
NAICS relies on a production-oriented or supply-based conceptual framework that groups establishments into industries according to similarity in the processes used to produce goods or services. *See*, https://www.census.gov/eos/www/naics/2017NAICS/2017_NAICS_Manual.pdf.

manufacturers who thought it was approximately representative, but potentially too low . In this preliminary analysis, DOE revised their base labor rate estimate to get a fully burdened labor cost of $80.86 as shown in Table 2.6.6.

Table 2.6.6 Labor Markups for Liquid-Immersed and Dry-Type Manufacturers

Value	Markup Percentage	2020 Price ($/lb)
Base Labor Rate ($/hr)	-	$21.43
Indirect Production	33%	$28.51
Overhead	30%	$37.06
Fringe	24%	$45.95
Assembly Labor Up-time	43%	$65.71
Nonproduction Mark-Up	25%	$82.14
Total Cost of Labor		$82.14

2.6.4.3 Shipping

In the April 2013 Standards Final Rule, DOE stated that because manufacturers typically absorb the cost of shipping, shipping costs were included in the manufacturer selling prices. 78 FR 23336, 23368-23369. Previously, DOE used a cost of $0.28 per pound of the overall distribution transformer. Based on interviews with manufacturers, manufacturers typically do not calculate shipping costs on a per-pound basis. Rather, shipping cost is a less well-defined function of several factors, including weight, volume, footprint, order size, destination, distance, and other, general shipping costs (fuel prices, driver wages, demand, etc.).

Based on interview feedback from manufacturers, a price-per-pound estimate is an appropriate approximation of shipping costs and reflects the increased shipping costs associated with larger distribution transformers (*i.e.*, where fewer would fit on a truck.) For this preliminary analysis, DOE maintained a shipping cost of $0.28 per pound and applied the nonproduction markup on top of the total shipping costs. These costs are included in the analyzed manufacturer selling price. This is discussed further in TSD chapter 5.

DOE requests comment on (1) its method for incorporating distribution transformer shipping costs; (2) its estimated shipping cost of $0.28 per pound; (3) its decision to incorporate the shipping costs prior to applying a nonproduction mark-up; (4) specific alternative methods of estimating shipping cost as a function of transformer attributes in addition to weight.

2.6.4.4 Nonproduction Mark-up

To account for manufacturers’ nonproduction costs and profit margin, DOE applies a nonproduction cost multiplier (the manufacturer markup) to the MPC. The resulting manufacturer selling price ("MSP") is the price at which the manufacturer distributes a unit into commerce. In the June 2019 Early Assessment RFI, DOE requested comment on maintaining the use of a manufacturer markup of 1.25 for liquid-immersed, LVDT and MVDT distribution transformers, consistent with the April 2013 Standards Final Rule.84 FR 28239, 28257-28258. Powersmiths commented that manufacturers selling above DOE's minimum efficiency standard may apply a higher mark-up as a result of having to seek out TOC customers. (Powersmiths, No. 3 at p. 4)

DOE did not receive any comments recommending a different manufacturer markup. In this preliminary analysis, DOE maintained a manufacturer markup of 1.25.

2.6.5 Cost-Efficiency Results

The results of the engineering analysis are reported as cost-efficiency data (or "curves") in the form of energy efficiency (in percentage) versus MSP (in dollars), which form the basis for subsequent analyses in the preliminary analysis. DOE developed fourteen curves representing the fourteen representative units. DOE implemented design options by analyzing a variety of core steel material, winding material and core construction method for each representative unit and applying manufacturer selling prices to the output of the model for each design option combination. See TSD chapter 5 for additional detail on the engineering analysis.

2.7 MARKUPS ANALYSIS

The markups analysis develops appropriate markups (*e.g.*, retailer markups, distributor markups, contractor markups) in the distribution chain and sales taxes to convert the MSP estimates derived in the engineering analysis to consumer prices, which are then used in the LCC and PBP analysis and in the manufacturer impact analysis. At each step in the distribution channel, companies markup the price of equipment to cover business costs and profit margin.

For distribution transformers, the main parties in the distribution chain differ depending on the type of distribution transformer being purchased.

2.7.1 Liquid-immersed Distribution Transformers Distribution Channels

For liquid-immersed distribution transformers, which are almost exclusively purchased and installed by electrical distribution companies, the channels are:

1) Manufacturer > Distributor > Customer Utility

2) Manufacturer > Customer Utility.

2.7.2 Dry-type Distribution Transformers Distribution Channels

For dry-type distribution transformers, which DOE has assumed are purchased by commercial and industrial customers, DOE considered the following distribution channel:

1) Manufacturer > Distributor > Electrical Contractor > C&I customer.

In the June 2019 Early Assessment RFI, DOE presented the market share of each of the distribution channels used in the April 2013 Standards Final Rule and requested comment whether those assumptions were still accurate. 84 FR 28239, 28252. The market share values are given in Table 2.7.1.

Table 2.7.1 Distribution Channels for Distribution Transformers

Type	Consumer	Distribution Channel	Market Share (%)
Liquid-Immersed	Investor-owned utility	Manufacturer → Consumer	82
		Manufacturer → Distributor → Consumer	18
	Publicly-owned utility	Manufacturer → Distributor → Consumer	100
LVDT	All	Manufacturer → Distributor → Electrical contractor→ Consumer	100
MVDT	All	Manufacturer → Distributor → Electrical contractor→ Consumer	100

HVOLT, NRECA, Hammond, and NEMA all commented that the presented market shares remain reasonable and supported retaining the same distribution channels. (HOVLT, No. 2 at p. 5; NRECA, No. 15 at p. 2; Hammond, No. 6 at p. 7; NEMA, No. 13 at p. 9)

DOE did not receive any comments recommending different distribution channels. In this analysis, DOE retained the distribution channels and distribution market shares presented in Table 2.7.1.

DOE developed baseline and incremental markups for each agent in the distribution chain. Baseline markups are applied to the price of equipment with baseline efficiency, while incremental markups are applied to the difference in price between baseline and higher-efficiency models (the incremental cost increase). The incremental markup is typically less than the baseline markup and is designed to maintain similar per-unit operating profit before and after new or amended standards.[17]

[17] Because the projected price of standards-compliant products is typically higher than the price of baseline products, using the same markup for the incremental cost and the baseline cost would result in higher per-unit operating profit. While such an outcome is possible, DOE maintains that in markets that are reasonably competitive it is unlikely that standards would lead to a sustainable increase in profitability in the long run.

DOE relied on RSMeans Electrical Cost Data, and stakeholder input to estimate average baseline and incremental markups.

DOE did not receive any comments recommending different markups. In this analysis, DOE retained the markups methodology described in chapter 6 of this TSD.

2.8 ENERGY USE ANALYSIS

The energy use analysis produces energy use estimates and end-use load shapes for distribution transformers. The energy use analysis estimates the range of energy use of distribution transformers in the field (*i.e.*, as they are actually used by consumers) enabling evaluation of energy savings from the operation of distribution transformer equipment at various efficiency levels, while the end-use load characterization allows evaluation of the impact on monthly and peak demand for electricity. The energy use analysis provides the basis for other analyses DOE performed, particularly assessments of the energy savings and the savings in operating costs that could result from adoption of amended or new standards.

Because the application of distribution transformers varies significantly by type of distribution transformer (liquid-immersed or dry-type) and ownership (electric utilities own approximately 95 percent of liquid-immersed distribution transformers; commercial/industrial entities use mainly dry type), DOE performed two separate end-use load analyses to evaluate distribution transformer efficiency. The analysis for liquid-immersed distribution transformers assumes that these are owned by utilities and uses hourly load and price data to estimate the energy, peak demand, and cost impacts of improved efficiency. For dry-type distribution transformers, the analysis assumes that these are owned by commercial and industrial ("C&I") entities, so the energy and cost savings estimates are based on monthly building-level demand and energy consumption data and marginal electricity prices. In both cases, the energy and cost savings are estimated for individual distribution transformers and aggregated to the national level using weights derived from either utility or commercial/industrial building data.

2.8.1 Hourly Energy Use Analysis (Liquid-immersed Distribution Transformers)

For utilities, the cost of serving the next increment of load varies as a function of the current load on the system. To appropriately estimate the cost impacts of improved distribution transformer efficiency, it is therefore important to capture the correlation between electric system loads and operating costs and between individual distribution transformer loads and system loads. For this reason, DOE estimated hourly loads on individual liquid-immersed distribution transformers using a statistical model that simulates two relationships: (1) the relationship between system load and system marginal price; and (2) the relationship between the distribution transformer load and system load. Both are estimated at a regional level.

2.8.1.1 Hourly Loading

In the June 2019 Early Assessment RFI, DOE presented background on how hourly load estimates were conducted for liquid-immersed distribution transformers during the April 2013 Standards Final Rule and requested comment and sources of data to support its hourly load model. 84 FR 28239, 28252-28253. NEMA commented that the values used for the April 2013 Standards Final Rule are sufficient and should be retained. (NEMA, No. 13 at p. 10) NRECA commented that the hourly load analysis makes sense. (NRECA, No. 15 at p. 3) NRECA stated that the peak load on residential units tends to be briefer than commercial applications and this should be taken into account. (NRECA, No. 15 at p. 3) HVOLT, Metglas, and NEMA recommended DOE look at the data collected by the IEEE Distribution Transformer Subcommittee Task Force. (HVOLT, No. 2 at p. 5; Metglas, No. 11 at p. 1; NEMA, No. 13 at p. 10) Metglas commented that the bottom-up approach used by IEEE shows that the average PUL is significantly less than DOE's previous estimates. (Metglas, No. 11 at p. 5-6)

Distribution transformer loading is an important factor in determining which types of distribution transformer designs will deliver a specified efficiency, and for calculating distribution transformer losses and the time dependent values of those losses. DOE examined the data made available through the IEEE Distribution Transformer Subcommittee Task Force.[18] For this analysis, DOE estimated a range of loading distributions for different types of liquid-immersed distribution transformers based on the analysis done for the April 2013 Standards Final Rule, supplemented with new data on hourly annual loads from over 65,000 individual distribution transformers submitted by distribution transformer customers. These data contained different load profiles for commercial and non-commercial customers in dense- and low-population areas, including their individual peak-load contributions, which were accounted for in this analysis. After analyzing these data, DOE found that the PULs in the most recent data are lower than the PULs estimated for the April 2013 Standards Final Rule, as indicated in Table 2.8.1.

Table 2.8.1 Comparison of Annual Average Liquid-Immersed Distribution Transformer Per-Unit Load

	EC 1 (1-phase)		EC 2 (3-phase)		
	RU 1 (50 kVA)	RU 2 (25 kVA)	RU 3 (500kVA)	RU 4 (150 kVA)	RU 5 (1500 kVA)
April 2013 Standards Final Rule	0.340	0.338	0.339	0.433	0.439
2021 Preliminary Analysis	0.290	0.273	0.320	0.295	0.305

[18] *See:* http://grouper.ieee.org/groups/transformers/subcommittees/distr/EnergyEfficiency/F20-DistrTransfLoading-Mulkey.pdf

2.8.1.2 Initial Peak Distribution Transformer Loading

DOE used a distribution of values for initial peak loading to characterize the annual peak load served by each distribution 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. In the April 2013 Standards Final Rule 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.[19] DOE found these values to be consistent with peak load in the supplied utility load data described in section 2.8.1.1 and maintained these values for this analysis. Given the provision for future growth, and short-term or emergency loading, 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 may be as high as 130 percent, because for short periods a transformer can be loaded to more than 130 percent of nameplate capacity. However, DOE understands that these peak loading assumptions are determined to satisfy the operations requirements on a per utility basis. Figure 2.8.1 illustrates the distribution of initial peak loading that DOE used.

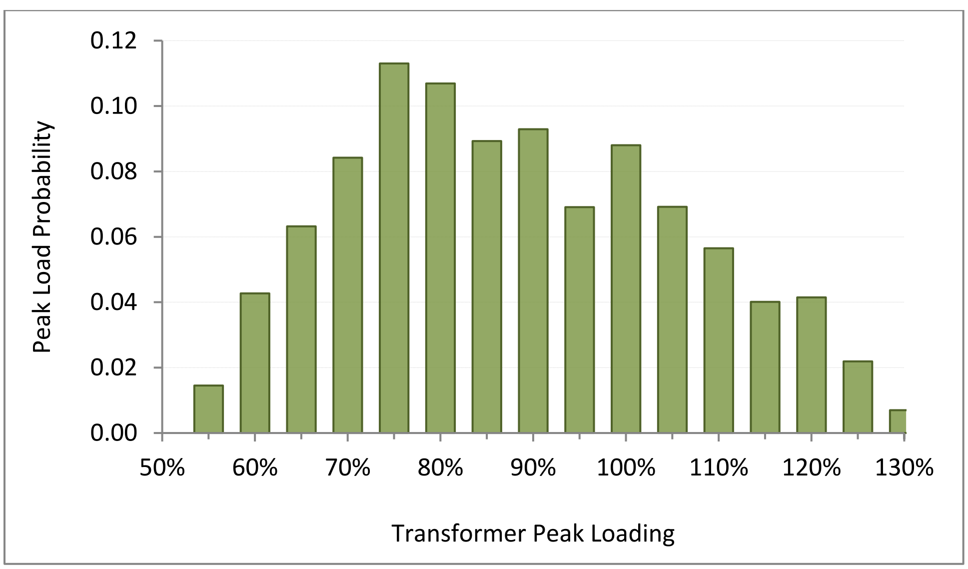


Figure 2.8.1 Distribution of Initial Peak Loading

2.8.1.3 Loss Factor

Transformer PUL is a useful metric for discussing the relative load of a transformer in relation to its nameplate capacity, however it can be misconstrued as a direct representation of transformer load losses. In the field, transformers are operated over a diverse range of PULs,

[19] See chapter 7 of the TSD for details.

often with the transformer's highest PUL being coincident with system peak. As discussed in section 2.6.2.3, transformer losses increase with the square of the load. This is captured in the energy analysis as the Loss Factor ("LF"), which is the fraction of full-load losses realized by a transformer and is calculated as:

$$LF = (RMS\ Load \times Initial\ Peak\ Load)^2$$

The distribution of average *LF* as a function of PUL for RU5 is shown in the density plot in Figure 2.8.2. This figure clearly shows that for a single average PUL, there is a diversity of loss factors.

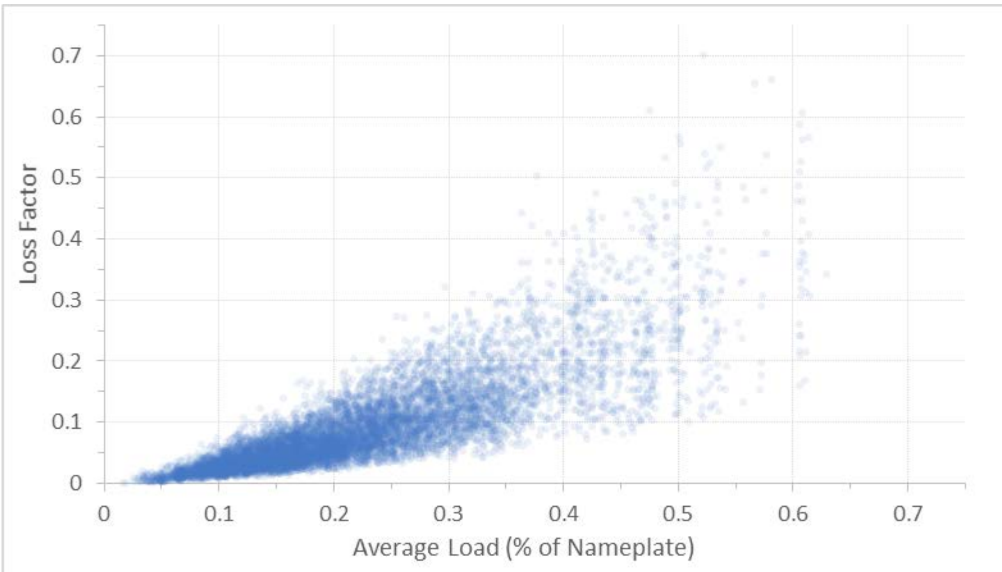


Figure 2.8.2 Distribution of Average Loss Factors

DOE seeks comment on the national representativeness of the average in-service PULs and Loss Factors of liquid-immersed distribution transformers show in Table 2.8.1.

DOE seeks comment on the national representativeness of the distribution of Initial Peak Load factors shown in Figure 2.8.1.

2.8.2 Monthly Energy Use Analysis (Dry-type Distribution Transformers)

DOE estimated the range of loading for different types of dry-type distribution transformers based on the analysis done for the April 2013 Standards Final Rule. Dry-type distribution transformers are primarily installed on buildings and owned by the building owner/operator. Commercial and industrial ("C&I") utility customers are typically billed monthly, with the bill based on both electricity consumption and demand. Hence, the value of improved distribution transformer efficiency depends on both the load impacts on the customer's electricity consumption and demand and the customer's marginal electricity prices.

In the June 2019 Early Assessment RFI, DOE presented the data sources used during the April 2013 Standards Final Rule for estimating the PUL for LVDT and MVDTs. 84 FR 28239, 28253-28254. DOE requested comment on the methodology for determining monthly loads for LVDT and MVDTs and the appropriateness of data sources used in deriving these estimates. *Id.* DOE also requested any field or simulated energy use data that would enhance DOE's analysis. *Id.*

HVOLT commented that the 2013 analysis is still reflective of the current environment and that there are a variety of uses for general purpose LVDTs so there is no absolute usage pattern for these distribution transformers. (HVOLT, No. 2 at p. 5) HVOLT also stated that LVDT PUL would not vary seasonally but MVDT may, depending on the application. (HVOLT, No. 2 at p. 5) Powersmiths commented that DOE's current method of extrapolating energy use from square footage is error-prone and DOE should instead use direct measuring of loading. (Powersmiths, No. 3 at p. 2) Powersmiths recommended DOE directly measure the loading from a large sample size of distribution transformers and document the k-factor and the data to understand how harmonic data impacts losses in the field. (Powersmiths, No. 3 at p. 2-3) Specifically, Powersmiths recommended that DOE commission a survey of 500 buildings across different vertical markets to get a more accurate understanding of PUL and losses. (Powersmiths, No. 3 at p. 3) Hammond commented that many utilities have energy data for each load point by hour and that these data could guide the methodology. (Hammond, No. 6 at p. 7)

Additionally, in response to the May 2019 TP NOPR, Powersmiths commented that a field study conducted by The Cadmus Group found that the in-service average RMS loads of 89 low-voltage dry-type distribution transformers had an average PUL of 15.9 percent, and an average peak PUL of 33 percent.[20] (Powersmiths, EERE-2017-BT-TP-0055 No. 0018-0003 at p. 2)

DOE agrees with Powersmiths that a multi-variate field-metering study to directly assess the usage of LVDT across different applications would be useful when modeling the monthly energy use. However, DOE is not considering a large field study of LVDT due to cost and time constraints. DOE welcomes stakeholders to submit any field-metering data. For this preliminary analysis, in the absence of new data, DOE approached the monthly energy use analysis using the same methodology as it did previously in the April 2013 Standards Final Rule.

---

[20] The Cadmus Group, *Transformers Efficiency: Unwinding the Technical Potential*, D. Korn, A. Hinge, F. Dagher, C Partrige, 1999.

DOE requests comment on the findings from The Cadmus Group study cited by Powersmiths. Specifically, DOE seeks comment on the national representativeness of the average in-service PUL of 15.9 percent for low-voltage dry-type distribution transformers, and the data supporting such comment. DOE requests additional information or data regarding the in-service PUL of low-voltage dry-type distribution transformers.

In this analysis DOE assumes 100 percent of medium-voltage dry-type transformers are owned and operated by commercial or industrial entities and calculates their energy use on a monthly basis. DOE request comment on this assumption.

2.8.3 Future Load Growth

While recent loading data can be used to estimate the current PUL of distribution transformers, DOE performs its energy-use analysis over the lifetime of the distribution transformer, during which the PUL may change depending on load growth in the future. In the June 2019 Early Assessment RFI, DOE requested comment and data regarding the estimated annual 0.5 percent load growth for liquid-immersed distribution transformers, and no annual load growth for dry-type distribution transformers, used in the April 2013 Standards Final Rule. 84 FR 28239, 28253.

HVOLT commented that while there has not been much load growth in recent years, due to efficiency improvements in electricity end uses served by utilities, the next 30 years are likely to see significant load growth due to the electrification of vehicles and heating systems, and the installation of air conditioning. (HVOLT, No. 2 at p. 5) NEMA commented that the current data from IEEE has not shown evidence of load growth but that there is little data. (NEMA, No. 13 at p. 10) Metglas commented that DOE's assumption of load growth on liquid-immersed distribution transformers is not correct and current data shows that there is little load growth after initial installation. (Metglas, No. 11 at p. 1-2) Metglas asserted that all electricity growth comes from installation of new distribution transformers, rather than load growth on existing distribution transformers. (Metglas, No. 11 at p. 8) Metglas further asserted that there is some evidence that PULs are falling in-line with ongoing efforts to improve the energy efficiency of products. (Metglas, No. 11 at p. 8) Regarding assertions that the proliferation of electric vehicles would increase distribution transformer loads, Metglas cited a Solar Energy Industries Association study that indicates that roof top solar photovoltaic systems will generate more electricity than electric vehicles will consume, resulting in no net load growth. (Metglas, No. 11 at p. 8) NRECA commented that there is a high degree of uncertainty on future load growth, because load growth varies among utilities and even within different applications at a given utility. (NRECA, No, 15 at p. 3) NRECA stated that given this variability DOE's previous estimates are as reasonable as any other estimate cited by stakeholders. *Id.*

As indicated by the comments received, that there are many factors that potentially impact load growth, and that these factors may be in opposition. While many utilities, states, and municipalities are pursuing electric vehicle charging programs, it is unclear the extent to which increases in electricity demand for electric vehicle charging, or other state level electrification/decarbonization efforts, will impact distribution transformer sizing practices (for example, whether distribution utilities plan to upgrade their systems to increase the capacity of connected distribution transformers—thus maintaining current loads as a function of distribution transformer capacity; or if distribution utilities do not plan to upgrade their systems and will allow the loads on existing distribution transformers to rise). For this analysis, DOE applied a load growth rate of 0.9 percent, based on U.S. Energy Information Administration ("EIA"), Annual Energy Outlook ("AEO") 2021 projected electricity sales, to liquid-immersed transformers, and zero percent for low- and medium-voltage dry-type transformers.

DOE requests comment on its proposed use of AEO 2021 projected electricity sales trend as a proxy for transformer load growth.

DOE requests comment on its proposed assumption of zero percent load growth on low-, and medium-voltage dry-type transformers.

2.8.4 Areas of Low Population Density

In rural areas, the number of customers per distribution transformer is lower and may result in lower PULs. In the April 2013 Standards Final Rule, DOE reduced the PUL by 10 percent for utilities serving counties with fewer than 32 households per square mile.[21] In the June 2019 Early Assessment RFI, DOE requested comment and data on the appropriateness of this adjustment. 84 FR 28239, 28253 Because the utilities serving areas of low population density might be disproportionally adversely affected by a potential change in the energy efficiency standards, DOE will examine the consumer impacts of these utilities with a separate life-cycle cost subgroup analysis as part of the NOPR. (see section 2.13)

Chapter 7 and its appendixes of this TSD provide details on DOE's energy use analysis for distribution transformers.

2.9 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.

---

[21] PUL estimates for utilities serving low population densities were not presented in the final rule Federal Register notice, but can be found on page 8-16 of chapter 8 of the April 2013 Standards Final Rule Technical Support Document, available from: https://www.regulations.gov/document?D=EERE-2010-BT-STD-0048-0760.

DOE analyzes the effect of new or amended standards on consumers by evaluating changes in LCC of owning and operating the equipment (chapter 8 of the TSD). To evaluate the change in LCC, DOE used the cost-efficiency relationship derived in the engineering analysis, along with the energy costs derived from the energy use characterization. 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.

Because the installed cost of equipment typically increases while operating cost typically decreases in response to standards, there is a time in the life of equipment having higher-than-baseline efficiency when the net 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 PBP.

DOE developed a sample of utilities that purchase liquid-immersed distribution transformers, and a sample of commercial and industrial entities that purchase LVDT and MVDT distribution transformers. By developing such samples, DOE was able to perform the LCC and PBP calculations for the different installations and consumers to account for the variability in energy consumption and load-based electricity price associated with actual users of the considered equipment. Other input values for estimating the LCC include electricity prices, discount rates, equipment location, equipment lifetime.

In response to the June 2019 Early Assessment RFI, NEMA and Eaton commented that a simplified methodology should be used to allow the public to more easily review the LCC estimates. (Eaton, No. 12 at p. 9; NEMA, No. 13 at p. 11) NRECA and HVOLT commented that the basic methodology is fine, (NRECA, No. 15 at p. 3; HVOLT, No. 2 at p. 5)

To the assertions from NEMA and Eaton that a simplified methodology should be used for the LCC, DOE notes that many of the complexities added to the LCC were at the request of stakeholders, and that calculating the total life-cycle costs of distribution transformers is, itself a complex process. DOE endeavors to transparently address the concerns of all stakeholders in its analysis, and creating a separate, second, simplified analysis could lead to confusions as to which analysis DOE would draw its conclusions from. At this point, DOE has no plans to create a second, simplified methodology and analysis.

For each considered efficiency level in each analyzed equipment class, DOE calculated the LCC and PBP for a nationally representative set of electric distribution utilities (for liquid-immersed distribution transformers), and C&I entities (for dry-type distribution transformers). DOE developed customer samples from different data sources for each different type of distribution transformer. For liquid-immersed distribution transformers DOE used data from the EIA, Annual Electric Power Industry Report, Form EIA-861 ("EIA 861"), and the Federal Energy Regulatory Commission Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report ("Form 714"). [22,23] For dry-type distribution transformers DOE used EIA's Commercial Buildings Energy Consumption Survey ("CBECS") and Manufacturing Energy

[22] https://www.eia.gov/electricity/data/eia861/, 2015

[23] https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/electronic, 2015

Consumption Survey ("MECS"). For each sample, DOE determined the energy consumption for the distribution transformers and the appropriate electricity price by analysis time increment (hourly for liquid-immersed, monthly for dry-type). By developing a representative sample of customers, the analysis captured the variability in energy consumption and energy prices associated with the use of distribution transformers experience by consumers.

Inputs to the calculation of total installed cost include the cost of the equipment—which includes MSPs, retailer and distributor markups, and sales taxes—and installation costs. Inputs to the calculation of operating expenses include annual energy consumption, energy prices and price projections, repair and maintenance costs, equipment lifetimes, and discount rates. DOE created distributions of values for equipment lifetime, discount rates, and sales taxes, with probabilities attached to each value, to account for their uncertainty and variability. The computer model DOE uses to calculate the LCC and PBP relies on a Monte Carlo simulation to incorporate uncertainty and variability into the analysis. The Monte Carlo simulations randomly sample input values from the probability distributions and distribution transformer user samples. For this rulemaking, the Monte Carlo approach is implemented in a program developed by DOE. The model calculated the LCC and PBP for equipment at each efficiency level for 10,000 consumers per simulation run. The analytical results include a distribution of 10,000 data points showing the range in LCC savings for a given efficiency level relative to the no-new-standards case efficiency distribution. In performing an iteration of the Monte Carlo simulation for a given consumer, equipment efficiency is chosen based on either the simulated distribution transformers TOC or lowest first cost. If the chosen equipment efficiency is greater than or equal to the efficiency of the standard level under consideration, the LCC and PBP calculation reveals that a consumer is not impacted by the standard level. By accounting for consumers who already purchase more-efficient equipment, DOE avoids overstating the potential benefits from increasing equipment efficiency.

DOE calculated the LCC and PBP for all consumers of distribution transformers as if each were to purchase new equipment in the expected year of required compliance with new or amended standards. Currently, DOE estimates publication of a final rule in 2024. For purposes of its analysis, DOE used 2027 as the first year of compliance with any amended standards for distribution transformers, if new or amended standards are proposed.

Table 2.9.1 summarizes the approach and data DOE used to derive inputs to the LCC and PBP calculations. The subsections that follow provide further discussion. Details of the model, and of all the inputs to the LCC and PBP analyses, are contained in chapter 8 of this TSD and its appendices.

Table 2.9.1 Summary of Inputs and Methods for the LCC and PBP Analysis*

Inputs	Source/Method
Equipment Cost	Derived by multiplying MPCs by manufacturer and distributor markups and sales tax, as appropriate. Used historical data to derive a price scaling index to project equipment costs.
Installation Costs	Baseline installation cost determined with data from RS Means. Installation Costs vary with transformer weight for some installations, otherwise the same costs are used in the baseline, and standard cases.
Annual Energy Use	The total annual energy use multiplied by the hours or months per year. Average number of hours based on field data. *Variability*: Based on distribution transformer load data or customer load data.
Energy Prices	*Electricity, hourly*: Based on EIA's Form 861 data for 2015, scaled to 2020. *Electricity, monthly*: Based on EEI and tariffs data from 2019, scaled to 2020. *Variability*: Regional energy prices determined for EMM and Census regions.
Energy Price Trends	Based on AEO2021 price by sector projections.
Repair and Maintenance Costs	Assumed no change with efficiency level.
Equipment Lifetime	Distribution with an average: 32 years
Discount Rates	DOE estimated a statistical distribution of commercial customer discount rates that varied by transformer type by calculating the cost of capital for the different types of transformer owners.
Compliance Date	2027

* References for the data sources mentioned in this table are provided in the sections following the table or in chapter 8 of this TSD.

2.9.1 Equipment Costs

To calculate consumer equipment costs, DOE multiplied the MSPs developed in the engineering analysis by the markups described previously (along with sales taxes). DOE used different markups for baseline equipment and higher-efficiency equipment because DOE applies an incremental markup to the increase in MSP associated with higher-efficiency equipment.

To forecast a price trend for this analysis, DOE derived an inflation-adjusted index of the Producer Price Index ("PPI") for electric power and specialty transformer manufacturing from 1967 to 2019.[24] These data show a long-term decline from 1975 to 2003, and an increase since then. There is considerable uncertainty as to whether the recent trend has peaked and would be followed by a return to the previous long-term declining trend, or whether the recent trend

[24] For this analysis DOE considered two Produce Price Indexes published by the U.S. Bureau of Labor Statistics for: Electric power and specialty transformer PPI (PCU335311335311), and Power and distribution transformers PPI (PCU3353113353111)

represents the beginning of a long-term rising trend due to global demand for distribution transformers and rising commodity costs for key distribution transformer components. Given the uncertainty, DOE chose to use constant prices (2020 levels) for both its LCC and PBP analysis and the NIA.

DOE requests comment on its assumption to use constant real prices of distribution between 2020 and 2027 in its LCC analysis.

2.9.2 Modeling Distribution Transformer Purchase Decision

The LCC model uses a purchase-decision model that specifies which of the hundreds of designs in the engineering database designed to meet a given efficiency level are likely to be selected by distribution transformer purchasers. The engineering analysis yielded a cost-efficiency relationship in the form of manufacturer selling prices, no-load losses, and load losses for a wide range of distribution transformer designs and costs.[25] This set of data provides the LCC model with a distribution of distribution transformer design choices.

DOE used an approach that focuses on the selection criteria customers are known to use when purchasing distribution transformers. Those criteria include first costs, as well as the TOC method. The TOC method combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have historically used the TOC method to determine which distribution transformers to purchase.

The utility industry developed TOC evaluation as a tool to reflect the unique financial environment faced by each distribution transformer purchaser. To express variation in such factors as the cost of electric energy, and capacity and financing costs, the utility industry developed a range of evaluation factors: A and B values, to use in their calculations.[26] A and B are the equivalent first costs of the no-load and load losses (in $/watt), respectively.

In the June 2019 Early Assessment RFI, DOE requested comment and data on its previous assumptions that 10 percent of liquid-immersed distribution transformer purchasers use the TOC methodology. 84 FR 28239, 28254 HVOLT commented that very few customers are currently using the TOC methodology. (HVOLT, NO. 2 at p. 5) NRECA commented that the TOC methodology used to be more popular, but with the higher efficiency standards purchasers found too little benefit to continue using TOC and have switched to first cost. (NRECA, No. 15 at p. 3) Metglas commented that fewer customers are using TOC now and agreed with DOE’s estimate in the April 2013 Standards Final Rule that only 10 percent of the liquid-immersed market is using the TOC methodology for purchasing. (Metglas, No. 11 at p. 3) Howard commented that they have a considerable number of customers using the TOC methodology and strongly support this approach for customers in higher cost energy areas. (Howard, No. 19 at p.

[25] See chapter 5 of the TSD for details.
[26] In modeling the purchase decision for distribution transformers DOE developed a probabilistic model of A and B values based on utility requests for quotations when purchasing distribution transformers. In the context of the LCC the A and B model estimates the likely values that a utility might use when making a purchase decision.

2) NEMA commented that utilities will sometimes use TOC whereas commercial entities do not. (NEMA, No. 13 at p. 11) DOE did not receive any comments recommending an alternate percent of purchasers using TOC in the liquid-immersed distribution transformer market.

Similarly, DOE requested comment on its assumption that zero percent of dry-type distribution transformer purchases were based on TOC. Hammond and HVOLT commented that TOC evaluations are rare in dry-type purchase decisions, because the purchaser is not the end user and therefore places little value on efficiency. (HVOLT, No. 2 at p. 5-6; Hammond, No. 6 at p. 7) Schneider commented that they do not receive requests for distribution transformers above the DOE standard—indicating that purchases are mostly made not using TOC. (Schneider, No. 8 at p. 5) Powersmiths commented that some customers, perhaps driven by voluntary building standards, do evaluate TOC but still end up purchasing on first cost. (Powersmiths, No. 3 at p. 3)

Based on the comments, DOE maintained much of its approach from the April 2013 Standards Final Rule: 10 percent of purchasers of liquid-immersed distribution transformers would purchase based on TOC, while the remaining 90 percent would purchase based on lowest first costs. For low- and medium-voltage dry-type distribution transformers, DOE revised its assumption to 100 percent of purchases would be based on lowest first costs. In addition to price, there are other details contributing to a "lowest-first-cost" purchase decision. Recognizing that prices vary slightly by order and customer for minor reasons, such as enclosure details, branding, or differences in competitive pricing, the analysis includes a uniform ±5 percent modifier to the MSPs developed in the engineering analysis.

The transformer selection approach is discussed in detail in chapter 8 of this TSD.

DOE requests comment on its assumption that 10 percent of liquid-immersed distribution transformers are purchased using TOC.

DOE requests comment on its assumption that 100 percent of low- and medium-voltage dry-type distribution transformers are purchased based on lowest first cost.

DOE understands that a portion of liquid-immersed purchases are made based on the industry term "Band of Equivalents" ("BoE"). DOE understands BoE to be method for consumers to establish equivalency between a set of transformer designs within a range of similar "Total Owning Costs" ("TOC"). BoE is defined as those transformer designs the range of similar TOCs; the range of TOC varies from utility to utility and is expressed in percentage terms. In practice, the purchaser would consider TOC the transformer designs with TOCs within, for example 10 percent, as equivalent – and would select the lowest first-cost design from this set. DOE seeks comment on (i) its understanding of Band of Equivalents; (ii) typical values used to define BoE, and (iii) typical rates of adoption exclusive of its current assumption of 10 percent of purchaser using TOC.

DOE requests information on whether those purchase decisions that are based on TOC differ by distribution transformer capacity (kVA). Are customers purchasing higher capacity distribution transformers more likely to purchase using TOC?

DOE requests comment on whether those consumers that purchase distribution transformers based on TOC are likely to pay higher electricity costs.

DOE requests comment on its assumption that transformer MSP will vary by ±5 percent. Further, DOE seeks comment of if this variability would change with transformer capacity (kVA).

DOE request comment on any other factors that may be considered when purchasing a transformer based on lowest-first cost.

DOE seeks information on different factors would lead to the purchase of a refurbished or rebuilt distribution transformer.

2.9.3 Installation Cost

Installation cost includes labor, overhead, and any miscellaneous materials and parts needed to install the equipment.

2.9.3.1 Impact of Distribution Transformer Size and Weight on Installation Costs

Total installation costs can depend on the size and weight of the equipment. In the June 2019 Early Assessment RFI, DOE requested information and data related to how installation cost changes as a function of distribution transformer size and weight for various types and capacities of distribution transformers. 84 FR 28239, 28254.

NEMA stated that the factors considered in the previous rulemaking are still valid and they are not aware of any new factors to consider. (NEMA, No. 13 at p. 12). For this analysis, as discussed in the following paragraphs, DOE reevaluated the methods it used in the April 2013 Standards Final Rule.

Higher efficiency distribution transformers may be larger and heavier than less efficient distribution transformers, with the degree of weight increase depending on how a distribution transformer's design is modified to improve efficiency. In the April 2013 Standards Final Rule, DOE estimated the increased cost of installing larger, heavier distribution transformers based on estimates of labor cost by distribution transformer capacity from Electrical Cost Data Book, by RSMeans. For the current analysis DOE retained certain portions of the prior approach where installation costs are based on the weight of the transformer for dry-type transformers, and updated its installation cost methodology for liquid-immersed transformers based on new findings described below.

For liquid-immersed distribution transformers, DOE reexamined the cost impacts of making like-for-like distribution transformer replacement into, and onto, existing utility structures. DOE surveyed several electric utilities through an engineering firm (SME) to inquire about their installation procedures and remediation practices when a new, potentially larger or heavier distribution transformer of the same capacity (in kVA) could not be installed in the desired location.[27] The weights for the distribution transformers covered under the scope of this analysis can be extremely heavy, ranging in weight from 450 pounds to over 15,000 pounds. DOE's survey found that distribution transformers are almost exclusively moved into place using mechanical equipment, for example bucket trucks, cranes, forklifts, pallet jacks, and/or hoists. Unless the change in distribution transformer weight is greater than the maximum safe operating limits of the mechanical equipment required for installation (meaning that mechanical equipment of greater capabilities would be needed), the same costs associated with the mechanical equipment and crew can be used for the baseline and replacement cases.

Hammond commented that, for dry-type distribution transformers, larger sizes and weight can have some impact. (Hammond, No. 6 at p. 8) For dry-type distribution transformers, which are typically installed indoors where access can be difficult, DOE maintained the

[27] See appendix 8D of the TSD for details.

methodology that it used in the April 2013 Standards final rule, where the installation costs increase as a function of increased transformer weight.

2.9.3.2 Pad Installations

Pad-mounted distribution transformers are typically installed on prefabricated concrete pads of different dimensions that are dependent on the footprint area of the to-be-installed new distribution transformer. In response to the June 2019 Early Assessment RFI, Howard commented that pad-mount distribution transformers have gotten too large for existing pads in some cases. (Howard, No. 19 at p. 2). Responses to DOE's survey regarding installation indicate that the increasing footprint of a replacement distribution transformer could be an issue in the future, and that while current designs are near the limits of existing installation sites, increasing footprint dimensions have not been an issue to date. Further, responses were mixed as to whether the radiators on larger capacity pad-mounted distribution transformers had to be contained within the footprint of the supporting concrete pad, or if they could overhang the footprint of the concrete pad. Respondents also stated that these circumstances can be avoided with proper specification of distribution transformer dimensions when making purchases. Pad-mounted transformers are typically not "off the shelf" equipment, and are engineered to order, where the dimensions are specified during the procurement process. For this analysis, DOE did not include additional installation cost for pad replacement as these costs can likely be avoided by customers specifying the dimensions of replacement distribution transformers to fit within a customer's area constraints.

DOE requests comment on which distribution transformer characteristics should be included when determining the overall size increase of distribution transformer footprint. Specifically, should DOE include the radiators as within the transformer footprint?

DOE requests data and feedback on the size limitations of pad-mounted distribution transformers. Specifically, what sizes, voltages, or other features are currently unable to fit on current pads, and the dimension of these pads.

DOE seeks data on the typical concrete pad dimensions for 50 and 500 kVA single-phase; and 500, and 1500 kVA three-phase distribution transformers.

DOE seeks data on the typical service lifetimes of supporting concrete pads.

2.9.3.3 Overhead Installations

In the June 2019 Early Assessment RFI, DOE stated that it is considering including costs to account for the rare occasions when a more efficient, pole-mounted replacement distribution transformer would require the installation of a new, higher-grade (greater strength) utility pole to support an increase in weight due to increased distribution transformer efficiency. 84 FR 28239, 28254-28255. DOE requested comment on its method for accounting for pole replacement, its understanding of pole upgrades because of increased distribution transformer efficiency and weight, and any other factors to consider. *Id.*

When evaluating the impacts of replacing existing pole-mounted distribution transformers, DOE assumes that the replacement equipment provides the same utility as the original equipment, *i.e.,* the same capacity (in terms of kVA), service provided, and number of phases.

In evaluating replacement of pole-mounted distribution transformers, DOE considers whether such replacement would result in pole overloading and therefore require a replacement of the pole. In general, factors for determining whether pole overloading would be an issue depend in part on the application of the pole. If the pole is installed along a feeder line with distribution lines extending tangentially out from the pole, this will be characterized by a reduction in wind span to below safe limits due to increased transformer weight . [28] If the pole is installed at the end of a line, and is guyed in place, it is considered a dead-end structure, and the pole must support the weight of the distribution transformer and connected lines; pole overloading occurs when the minimum lead guy length for that pole exceeds safe limits.

Other factors must be considered to determine if pole overloading would occur, such as the capacity, number, shape, weight, and dimensions of distribution transformer(s) being replaced; class and height of pole on which the distribution transformers are to be mounted; where on the pole the distribution transformer(s) is to be mounted; what primary and secondary conductors are attached to the pole; the quantity, type and where these conductors are mounted; how many underbuilds, their diameters, and where on the pole they are mounted; what is the required grade of construction; the exiting wind span on the section of feeder line, or maximum shortest guy requirements of the original dead-ended pole; and in which climate loading zone (either NESC or GO95) the poles in question are located.[29,30, 31]

---

[28] Allowable wind span refers to the horizontal distance between the mid-span points of adjacent spans; in this case the length of horizontal conductor between two poles, measured at the mid-points.

[29] The National Electrical Safety Code® (NESC®). NESC governs the United States standard of the safe installation, operation, and maintenance of electric power and utility systems overhead lines in addition to other topics. For more information see: https://standards.ieee.org/products-services/nesc/index.html

[30] General Order 95 (GO95). GO95 governs, for the state of California, uniform requirements for overhead electrical line construction, and to secure safety to persons engaged in the construction, maintenance, operation or use of overhead electrical lines and to the public in general. For more information see: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M217/K418/217418779.pdf

[31] Both NESC and GO95 divide the Nation, and California in the case of GO95, into regions that experience climatic conditions that add physical stressors, such as wind and ice, on utility structures. NESC divides the Nation into heavy, medium, and light regions, while GO95 divides California into heavy and light regions. In both cases, the region effects the input assumptions for calculating utility structure strength, and their resistance to loads.

DOE notes that wooden poles have finite lifespans and need to be periodically replaced due to decay or other reasons, such as line upgrades; physical damage from wind, ice, or cars; ground shifting; *etc*. There will be a segment of any pole population at or near the end of its safe operating lifetime due to age and operational life cycle. In these circumstances each utility must evaluate the safety of its pole/structure before installing replacement equipment. In certain cases, the replacement of a pole may be needed independent of the characteristics of a replacement distribution transformer. DOE does not consider the cost of replacing the pole to maintain safe operations to be an additional burden to a consumer if this occurrence is needed in the absence of any potential revised standard. These costs are not related to increased distribution transformer efficiency.

To assist with its modeling of the potential of pole overloading due to increased distribution transformer weight, DOE commissioned a methodological report and model from Line Design University.[32] The report and model are available for review in appendix 8C of the TSD.

Howard commented that size and weight constraints are especially important for large pole-mounted distribution transformers that are cluster mounted. (Howard, No. 19 at p. 2) In response to Howard's comment, DOE examined the impacts on allowable wind spans for a bank of 3, single-phase, 167 kVA distribution transformers serving loads in a densely populated area in a NESC Heavy Loading District—Combined Wind and Ice with the following parameters.

- Grade B construction
- Conductors: 3 Æ 4/O ACSR (6/1) conductors
- 4-inch telecommunication – underbuilt.
- NESC Heavy Loading District – Combined Wind and Ice
- Pole: Class 1 — 40 feet (36 feet above ground)

For this scenario DOE considered wind spans between 100 and 150 feet to be typical for densely populated areas. Further, as DOE did not explicitly model a 167 kVA distribution transformer as part of its engineering analysis, DOE estimated the weights in the no-new standards and at max-tech (EL 5), the heaviest designs, by scaling the representative unit 2, a 25 kVA round tank; these resulted in a per distribution transformer weight ranging from 1,870 pounds in the no-new standards case to 3,270 pounds in the max-tech case. DOE found that the increase in transformer weight reduced the allowable wind span from 236 to 193 feet. At the maximum analyzed efficiency in the max-tech case DOE found that the reduced allowable wind span was still greater than the assumed typical allowable wind span of 150 feet, and that no replacement pole would be needed. DOE agrees with Howard that to the extent that larger distribution transformers are banked, installation issues may arise; however, without data as to when and how often such installation circumstances occur, DOE is limited in its ability to model such impacts.

NRECA commented that many IOUs and municipalities would not experience issues with pole replacement because the weight and size of a pole-mounted distribution transformer is

[32] See: https://www.linedesignuniversity.com/

a significantly lower percentage of the overall load many of their poles must support. (NRECA, No. 15 at p. 3) Further, NRECA stated that rural systems, by contrast, are built in less dense areas and spaced further apart, making the weight issue especially relevant. *Id.* NRECA estimated that the larger sized amorphous distribution transformers would require co-ops to replace 25 percent or more of their transformer poles. *Id.*

In response to NRECA's comment DOE analyzed the following pole loading scenarios characterized by the average baseline distribution transformer versus the average max-tech (amorphous) distribution transformers examined in this analysis. DOE examined the increase in distribution transformer weight for a 25 kVA, as it is the most typical pole-mounted distribution transformer, with the following installation criteria:

- Grade B construction
- Conductors: 1Æ, and 3 Æ 4/O ACSR (6/1)
- NESC Heavy Loading District – Combined Wind and Ice
- Pole height: 40 feet (36 feet above ground)

For these scenarios DOE considers the wind spans in Table 2.9.2 to be typical for rural or low population areas where efforts are made to serve customers with the fewest structures while maintaining the minimum clearances dictated by NESC or GO95.

Table 2.9.2 Assumed Typical Wind Spans by NESC Loading District for Rural Areas

NESC Loading District	Minimum Wind span (feet)	Maximum Wind span (feet)
Heavy	250	275
Medium	275	325
Light	325	375

The first scenario examines upgrading a single, 25 kVA distribution transformer with a baseline weight of 450 pounds to a replacement distribution transformer at the max-tech standards case, with a weight of 787 pounds. This scenario assumed single-phase conductors, a class 4 pole, and no underbuilds. DOE found the allowable wind span was reduced from 422 to 409 feet, a distance well above the minimum wind span in Heavy Loading Districts of 250 feet. DOE then evaluated the same distribution transformer when installed with three-phase conductors on a class 3 pole. DOE found the wind span would be reduced from 294 to 286 feet, again, a distance greater than 250 feet minimum allowable wind span of the Heavy Loading Districts.

Given the above scenarios, DOE finds that the increase in weight in the standards case results in small reductions in allowable wind span. As a result, DOE has not included pole replacement in this analysis. DOE invites NRECA to share the details of their analysis indicating that 25 percent or more of their utility poles would need to be replaced with DOE.

NRECA stated that the impact pole replacements would have on reliability is another concern but provided no further explanation. (NRECA, No. 15 at p. 3) DOE is unaware of reliability concerns that would be associated with pole replacement in those limited instances in which pole replacement would be necessary due to increased transformer efficiency. DOE requests further comment on the potential for reliability concerns related to pole replacement.

DOE request comment on its assumption to not include pole replacement costs as part of this analysis.

DOE requests comment and data regarding the examples presented here used to inform DOE's decision to not include pole replacement costs in this analysis.

DOE requests sources of data on the typical wind spans, pole configuration (quantity, type and installation parameters of conductors; pole grade and height) by transformer capacity and bank rating for rural, suburban, and urban services.

DOE seeks comment on the model contained within appendix 8C, Impact on Structures Caused from Increased Transformer Size.

DOE seeks information to better characterize typical overhead installations. DOE seeks the following information regarding pole characteristics by transformer capacity, number of transformers in the bank, and number phases of delivered service: (i) assumed rated windsapn or rated shortest guyed lead for deadended structures (in feet), (ii) service demographic (*e.g.* urban, suburban, rural), (iii) pole classification and height, (iv) conductor quantity, diameter(s), and height(s) mounted above the ground, (v) transformer(s) mounting height, and distance between transformer and pole, (vi) underbuild quantity, diameter(s), and height(s) above ground, and (vii) NESC/GO-95 loading region, and if extreme ice is a factor.

2.9.3.4 Vault (Underground) and Subsurface Installations

As discussed in section 2.4.2.3, in the context of this analysis, DOE uses the term "vault distribution transformer" to mean a distribution transformer specifically designed for and installed in an underground, below-grade, vault. These vaults are typically underground concrete rooms with an access opening in the ceiling through which the transformer can be lowered for installation or replacement. Because the consumers who purchase vault or subsurface transformers might be disproportionally adversely affected by a potential change in the energy efficiency standards, DOE will examine the consumer impacts of vault and subsurface with a separate consumer subgroup analysis as part of the NOPR analysis. (see section 2.13)

2.9.4 Electricity Costs

DOE derived electricity prices for distribution transformers using two different methodologies to reflect the differences in how the electricity is paid for by consumers of distribution transformers. For liquid-immersed transformers, which are largely owned and operated by electric distribution companies who purchase electricity from a variety of markets, DOE developed an hourly electricity costs model. For low- and medium-voltage dry-type transformers, which are primarily owned and operated by C&I entities, DOE developed a monthly electricity cost model.

2.9.4.1 Hourly Electricity Costs

To evaluate the electricity costs associated with liquid-immersed distribution transformers, DOE used marginal electricity prices. The general structure of the hourly marginal cost methodology divides the costs of electricity into capacity components and energy cost components. For each component, the economic value for both no-load losses and load losses is estimated. The capacity components include generation and transmission capacity; they also include a reserve margin for ensuring system reliability, with factors that account for system losses. Energy cost components include a marginal cost of supply that varies by the hour.

The marginal costs methodology was developed for each regional Balancing Authority listed in EIA's Form EIA-861 database (based on "Annual Electric Power Industry Report").[33] 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

[33] Available at *http://www.eia.doe.gov/cneaf/electricity/page/eia861.html*.

dispatch, are filed by control area operators under FERC Form 714.[34] These methodologies remain unchanged from the April 2013 Standards Final Rule.

As part of the hourly electricity costs analysis DOE developed a methodology to calculate the value of future avoided capacity costs resulting from greater transformer efficiency. This capacity costs component is determined for the set of regions defined in the EIA's National Energy Modeling System ("NEMS") electricity market module ("EMM").[35]

The method depends on the type of electricity generation constructed to meet future electricity demand. For this analysis, to reflect future competitive, and regulatory changes in electricity generation assumed in AEO 2021, DOE changed its assumptions of which generation capacity types would be used to meet future no-load and load losses.[36] In the April 2013 Standards Final Rule, DOE based its assumption on AEO 2012, that a mix of generating types (coal, renewables, combined cycle—conventional gas), and combined cycle—conventional gas would be constructed to meet future no-load load losses, and load losses, respectively.[37] For this analysis DOE assumed that natural gas combined-cycle—multi shaft, and combined-cycle—single shaft capacity types would be constructed to meet future no-load losses, and load losses, respectively.

This resulted in a material change in operating and maintenance ("O&M") costs between the April 2013 Standards Final Rule and this analysis, as shown in Table 2.9.3. The change in these values, while decreasing overall, puts greater value of constructing new capacity to serve load losses over no load losses.

Table 2.9.3 Change in Fixed O&M Cost for No-load and Load Losses

	April 2013 Standards Final Rule (2010$/kW-yr)	**This Analysis** (2019$/kW-yr)
No-load Losses	21	12
Load Losses	7	14

These changes are reflected in the Department's estimation of the average marginal cost per-kWh for no-load and load losses as function of RMS load shown in Figure 2.9.1. This figure shows that the capacity charges for no-load losses have a low impact to the total per $/kWh cost of electricity relative to the capacity changes for load losses. While the capacity charge for load losses can range significantly depending on the transformer's loss factor and its peak coincident

[34] Federal Energy Regulatory Commission, *Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report*, Washington, D.C., 2015
[35] Energy Information Administration - Office of Integrated Analysis and Forecasting. *The National Energy Modeling System (NEMS): An Overview*. (U.S. Department of Energy, 2009). at <http://www.eia.doe.gov/oiaf/aeo/overview/>
[36] Energy Information Administration - Office of Integrated Analysis and Forecasting. *Assumptions to AEO 2021(U.S. Department of Energy, (2021).* at <https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf>
[37] Energy Information Administration - Office of Integrated Analysis and Forecasting. *Assumptions to AEO 2012 (U.S. Department of Energy, (2012).* at <https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2012).pdf>

factor; specifically, the capacity cost can be a large portion of the cost of transformer operation especially if the transformer operation coincides with system peak—even at low average PULs.

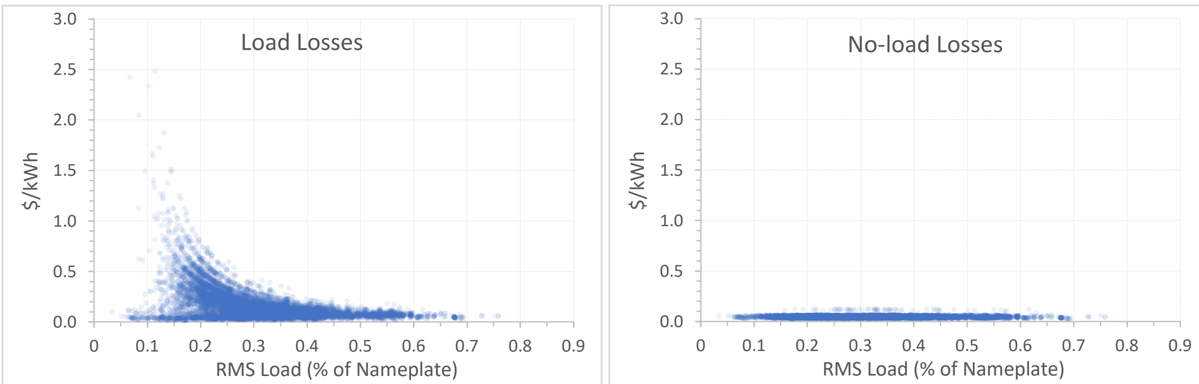


Figure 2.9.1 Average Cost for Load and No-load Losses for Liquid-immersed Distribution Transformers ($/kWh)

DOE seeks comment on its changes to the capacity costs inputs described in section 2.9.4.1

Capacity costs are discussed in detail in chapter 8 of this TSD.

2.9.4.2 Monthly Electricity Costs

To evaluate the electricity costs associated with LVDT and MVDT distribution transformers, DOE derived nationally representative distributions of monthly marginal electricity prices for different consumer categories (industrial, commercial, and residential) from the most recent data available in the EIA Form 861, "Annual Electric Power Industry Report," as well as data from the Edison Electric Institute.[38] Powersmiths commented that it is valid for DOE to use marginal rates since LVDT distribution transformers typically experience their peak loads during the grid peak. (Powersmiths, No. 3 at p. 4)

2.9.4.3 Future Electricity Prices

In the June 2019 Early Assessment RFI, DOE requested comment on its proposed method for estimating the future price of electricity. *Id.*

[38] Edison Electric Institute. *Typical Bills and Average Rates Report.* Washington, D.C., October 2019.

EEI and APPA commented that the real price of electricity has increased only minimally over the past several years, which has lengthened payback periods of high efficiency equipment relative to those DOE forecasted previously (assuming larger increases in electricity price forecasts). (EEI, No. 10 at p. 3, APPA, No. 16 at p. 2-3) They recommend DOE include this lack of price increase in its analysis. *Id.* To estimate electricity prices in future years, DOE multiplied the electricity prices described above by a reference case projection of annual change in national average electricity prices for commercial and industrial customers in AEO 2021.[39] AEO 2021 forecasts energy prices through 2050; to estimate prices after 2050, DOE maintained electricity prices at their 2050 levels through the end of the analysis period. In response to comments from EEI and APPA, DOE notes that the future price trends from AEO 2021 show a slight decrease in real electricity prices over time, which is reflected in DOE's electricity prices.

2.9.5 Maintenance and Repair Costs

Repair costs are associated with repairing or replacing equipment components that have failed; maintenance costs are associated with maintaining the operation of the equipment. Typically, small incremental increases in equipment efficiency produce no, or only minor, changes in repair and maintenance costs compared to baseline efficiency equipment. DOE did not receive any comments on the subject of transformer maintenance and repair costs and assumed they would be the same in the no-new-standards case and potential amended standards cases.

DOE requests comment on its assumption that maintenance and repair costs do not increase with transformer efficiency.

2.9.6 Discount Rates

The discount rate is the rate at which future expenditures are discounted to estimate their present value. DOE employs a two-step approach in calculating discount rates for analyzing customer economic impacts. The first step is to assume that the actual customer cost of capital approximates the appropriate customer discount rate. The second step is to use the use the capital asset pricing model (CAPM) to calculate the equity capital component of the customer discount rate. For this analysis, DOE estimated a statistical distribution of commercial customer discount rates that varied by transformer type by calculating the cost of capital for the different types of transformer owners, these can be found chapter 8.

HVOLT commented that the inflation rate and cost of borrowed funds seemed too high. (HVOLT, No. 2 at p. 5) The intent of the LCC analysis is to estimate the economic impacts of higher-efficiency transformers over a representative range of customer situations. While the

[39] EIA. Annual Energy Outlook 2021 with Projections to 2050. Washington, DC. Available at *http://www.eia.gov/forecasts/aeo/*.

discount rates used may not be applicable for all customers, they reflect the financial situation of the majority of transformer customers.

2.9.7 Equipment Lifetime

DOE defines distribution transformer life as the age at which the distribution transformer is retired from service. In the April 2013 Standards Final Rule, DOE estimated, based on a report by Oak Ridge National Laboratory ("ORNL-6847"),[40] that the average life of liquid-immersed distribution transformers is 32 years with a maximum lifetime of 60 years. 78 FR 23336, 23377.

Schneider recommended that DOE use guidance from Institute of Electrical and Electronics Engineers ("IEEE") standards to estimate equipment lifetimes. (Schneider, No. 8 at p. 5) Although Schneider did not specify which IEEE standard DOE should use as guidance, DOE assumes that Schneider is referring to IEEE C57-100, *Standard Test Procedure for Thermal Evaluation of Insulation Systems for Liquid-Immersed Distribution and Power Transformers*, where transformer life is modelled as a function of aging temperature. DOE notes that in the field distribution transformers are retired for reasons in addition to the aging effects on insulation media due to high temperatures. Other reasons for failure can include auto accidents, corrosive failure of the enclosure, short-circuit failure, and building renovation where the transformer is removed from service. Due to the limited scope of IEEE C57-100, DOE retained its approach from the April 2013 Standards Final Rule.

DOE requests comment on the appropriateness of using the distribution of lifetimes with an average 32-year lifetime from ORNL-6847 for all distribution transformers.

DOE requests comment or information on alternative lifetimes for low-voltage dry-type, and medium-voltage dry-type distribution transformers.

2.10 SHIPMENTS ANALYSIS

DOE uses projections of annual equipment shipments to calculate the national impacts of potential amended or new energy conservation standards on energy use, net present value ("NPV"), and future manufacturer cash flows.[41] The shipments model takes an accounting approach, tracking market shares of each equipment class and the vintage of units in the stock.

[40] Barnes. Determination Analysis of Energy Conservation Standards for Distribution Transformers. ORNL-6847. 1996.

[41] DOE uses data on manufacturer shipments as a proxy for national sales, as aggregate data on sales are lacking. In general one would expect a close correspondence between shipments and sales.

Stock accounting uses equipment shipments as inputs to estimate the age distribution of in-service equipment stocks for all years. The age distribution of in-service equipment stocks is a key input to calculations of both the National Energy Savings ("NES") and NPV, because operating costs for any year depend on the age distribution of the stock.

In the June 2019 Early Assessment RFI, DOE presented the methodology used for estimating shipments during the previous rulemaking, and requested comment on whether this approach is still valid. 84 FR 28239, 28255-28257. DOE further requested comment on its estimates of equipment life, purchase price elasticity—specifically regarding the use of refurbished distribution transformers instead of new purchases—and assumptions regarding consumer response to amended standards. *Id*. NEMA commented that there have not been significant changes to warrant a change to the shipment estimation methodology. (NEMA, No. 13 at p. 13) NRECA commented that it agrees with DOE's current methodology for estimating equipment lifecycle. (NRECA, No. 15 at p. 3)

DOE projected distribution transformer shipments for the no-new standards case by assuming that long-term growth in distribution transformer shipments will be driven by long-term growth in electricity consumption. DOE developed its initial shipments inputs based on data from the previous final rule, and data submitted to DOE from interested parties; these initial shipments are shown for the assumed compliance year, by distribution transformer type in chapter 9 of the TSD. DOE developed the shipments projection for liquid-immersed distribution transformers by assuming that annual shipments growth is equal to growth in electricity consumption for all sectors, as given by the *AEO 2021* forecast through 2050. DOE assumed that growth in annual shipments of dry-type distribution transformers would be equal to the growth in electricity consumption for commercial and industrial sectors. For the years beyond 2050, DOE used the constant annual rate of 2050 through the end of the analysis period. The model starts with an estimate of the overall growth in distribution transformer capacity, and then estimates shipments for representative units and capacities using estimates of the recent market shares for different design and size categories.

NRECA commented that some investor-owned utilities with more industrial and commercial loads are more likely to purchase larger three-phase liquid-immersed distribution transformers than cooperatives. (NRECA, No. 15 at p. 3) For this analysis DOE distributed the fraction of shipments to "publicly owned utilities" (municipal and co-operative utilities) based on the share of their electricity sales reported in EIA-Form 861.[42]

DOE requests comment on the fraction of liquid-immersed distribution transformers by capacity and number of phases used by the various utility segments, including publicly owned utilities.

[42] Annual Electric Power Industry Report, Form EIA-861

Powersmiths commented that it was expected a higher rate of future of low-voltage dry-type transformers would be replacements (retrofits), as distribution transformers installed during the increased construction of the 1970s reach the end of their lifetimes. (Powersmiths, No. 3 at p. 4) For this analysis DOE did not have sufficient data regarding replacement sales as compared to new units to change its approach.

DOE seeks comment on the appropriateness of using commercial and industrial electricity consumption as suitable drivers for future shipments of dry-type distribution transformers. DOE seeks information on other data sources indicating a significant rate of future replacements.

2.10.1 Rebuilt Transformers

NRECA commented that the rebuild and refurbishment market is strong and viewed positively by co-operative utilities. (NRECA, No. 15 at p. 3) APPA and EEI speculated that if future efficiency standards make it difficult for new transformers to match the size and weight of existing distribution transformers, companies would likely invest substantially in repairing and reconditioning transformers rather than replacing those units. (APPA, No. 16 at p. 4; EEI, No. 10 at p. 3)

DOE recognizes that consumers of distribution transformers may purchase equipment that is either rebuilt or refurbished and therefore not subject to potentially amended energy conservation standards and not addressed by this analysis. It is unclear from the comments submitted by NRECA, APPA and EEI whether their viewing of the rebuilt or refurbished market in a positive light is an indication that there is an increasing or decreasing trend toward this equipment. Neither NRECA, APPA or EEI were able to provide data, or an example, from their members of the some of the parameters, or the amount of change of those parameters, that characterize the decision of a consumer to forego the purchase of a new compliant distribution transformer in favor of rebuilt or refurbished equipment. For this analysis, DOE was unable to characterize the factors that go into the decision to purchase rebuilt or refurbished over new distribution transformer, and assumed that there would be no change in purchasing practice under a potential new standard.

DOE requests comment and additional data on the factors that go into the decision to purchase rebuilt transformers instead of new transformers, and the likely extent of such purchases in response to amended standards

Chapter 9 of this TSD provides a detailed description of how DOE projected shipments for each of the equipment classes.

DOE request comment and additional data on its shipments estimates. For this analysis, DOE assumed that the fraction of shipments by each capacity to be static over time. DOE requests information and additional data on whether there is an expected shift from one capacity to another over time.

2.11 NATIONAL IMPACT ANALYSIS

The national impact analysis assesses the aggregate impacts at the national level of potential energy conservation standards for each of the considered equipment, as measured by the NPV of total consumer economic impacts and the NES. DOE determined the NPV and NES for the efficiency levels considered for each of the equipment classes analyzed. To make the analysis more accessible and transparent to all interested parties, DOE prepared a model to forecast NES and the national consumer economic costs and savings resulting from the amended standards. The model uses typical values as inputs (as opposed to probability distributions). To assess the effect of input uncertainty on NES and NPV results, DOE may conduct sensitivity analyses by running scenarios on specific input variables. Chapter 10 of this TSD provides additional details regarding the national impact analysis.

Several of the inputs for determining NES and NPV depend on the forecast trends in equipment energy efficiency. For the no-new-standards case (which presumes no revised standards), DOE uses the efficiency distributions which are output from the customer choice model in the LCC analysis (see section 2.9.2). This produces for each equipment class, a different distribution of transformers efficiency at each standard level based on the combination of consumers purchasing based on TOC or lowest first costs. For this analysis DOE assumed that these efficiencies are static over time.

2.11.1 National Energy Savings

The inputs for determining the NES for the equipment analyzed are: (1) annual energy consumption per unit; (2) shipments; (3) equipment stock; (4) national site energy consumption; and (5) site-to-source conversion factors. DOE calculated the national energy consumption by multiplying the number of units, or stock, of the equipment (by vintage, or age) by the unit energy consumption (also by vintage). DOE calculated annual NES based on the difference in national energy consumption for the base case (without new efficiency standards) and for each higher efficiency standard. DOE estimated energy consumption and savings based on site energy and converted the electricity consumption and savings to source primary) energy. Cumulative energy savings are the sum of the NES for each year. DOE also calculated full-fuel-cycle NES, which accounts for the energy consumed in extracting, processing, and transporting or distributing primary fuels.

2.11.2 Net Present Value of Consumer Benefit

The inputs for determining NPV of the total costs and benefits experienced by consumers of the considered equipment 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 the equipment. NPV is 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 percent and 7 percent to discount future costs and savings to present values.

DOE calculated increases in total installed costs as the product of 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 costs 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 efficiency 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.

2.12 PRELIMINARY MANUFACTURER IMPACT ANALYSIS

DOE performed a preliminary manufacturer impact analysis (MIA) (chapter 12 of the TSD) to estimate the financial impact of amended energy conservation standards on distribution transformers manufacturers, 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 these three industries. The GRIM inputs are information on 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 manufacturer subgroups.

DOE conducts each MIA in three phases and will further tailor the analytical framework for each MIA based on comments from interested parties. In Phase I, DOE creates an industry profile to characterize the industry and identify important issues that require consideration. In Phase II, DOE prepares an industry cash-flow model and interview questionnaire to guide subsequent discussions. In Phase III, DOE interviews manufacturers and assesses the impacts of standards quantitatively and qualitatively. DOE assesses industry and subgroup cash flow and NPV using the GRIM. DOE then assesses impacts on competition, manufacturing capacity, employment, and regulatory burden based on manufacturer interview feedback and discussions.

DOE has evaluated and is reporting preliminary MIA information in this preliminary analysis (see chapter 12 of the preliminary TSD).

As part of the NOPR, DOE will seek comments from manufacturers about their potential loss of market share, changes in the efficiency distribution within each industry, and the total reduction in equipment shipments at each new energy conservation standard level. DOE will then estimate the impacts on the industry quantitatively and qualitatively.

The following is an overview of the information DOE intends to collect and analyze.

2.12.1 Industry Cash-Flow Analysis

The industry cash-flow analysis relies primarily on the GRIM. DOE uses the GRIM to analyze the financial impacts of more stringent energy conservation standards on the industry that produces the equipment covered by the standard. The GRIM analysis uses many factors to determine annual cash flows from a new standard: annual expected revenues; manufacturer costs, including cost of goods sold, depreciation, research and development, selling, general, and administrative expenses; taxes; and conversion capital expenditures. DOE compares the results against no-standards case projections that involve no new standards. The financial impact of new standards is then the difference between the two sets of discounted annual cash flows. Other performance metrics such as return on invested capital are available from the GRIM. For more information on the industry cash-flow analysis, refer to chapter 12 of the TSD.

2.12.2 Manufacturer Subgroup Analysis

Industry cost estimates are not adequate to assess differential impacts among subgroups of manufacturers. For example, small and niche manufacturers, or manufacturers whose cost structure differs significantly from the industry average, could be more negatively affected by the imposition of standards. Ideally, DOE would consider the impact on every firm individually; however, since this usually is not possible, DOE typically uses the results of the industry characterization to group manufacturers exhibiting similar characteristics.

2.12.3 Competitive Impacts Assessment

DOE must consider whether a new standard is likely to reduce industry competition, and the Attorney General must determine the impacts, if any, of reduced competition. DOE will make a determined effort to gather and report firm-specific financial information and impacts. The competitive impacts assessment will focus on assessing the impacts on smaller manufacturers. DOE will base this assessment on manufacturing cost data and information collected from interviews with manufacturers. The interviews will focus on gathering information to help assess asymmetrical cost increases to some manufacturers, increased proportion of fixed costs potentially increasing business risks, and potential barriers to market entry (*e.g.*, proprietary technologies). The NOPR will be submitted to the Attorney General for a review of the impacts of standards on competition. The Attorney General's comments on the proposed rule will be considered in preparing the final rule.

2.12.4 Cumulative Regulatory Burden

One aspect of assessing manufacturer burden involves looking at the cumulative impact of multiple DOE standards and the product-specific regulatory actions of other Federal agencies that affect the manufacturers of a covered product or equipment. While any one regulation may not impose a significant burden on manufacturers, the combined effects of several existing or impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Multiple regulations affecting the same manufacturers can strain profits and lead companies to abandon 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. DOE will analyze and consider the impact on manufacturers of multiple product-specific, Federal regulatory actions.

2.12.5 Preliminary Results for the Manufacturer Impact Analysis

In this preliminary analysis, DOE presents its assumptions and initial calculations. DOE relied on publicly available information as well as data from the April 2013 Standards Final Rule. For more details, see chapter 12 of the TSD.

2.13 CONSUMER SUBGROUP ANALYSIS

The consumer subgroup analysis (chapter 11 of the TSD) evaluates economic impacts on selected customer subgroups who might be adversely affected by a change in the National energy conservation standards for the considered equipment. DOE evaluates impacts on particular subgroups of customers by analyzing the LCC impacts and PBP for those particular customers.

2.13.1 Utilities Serving Low Populations

In rural areas, the number of customers per distribution transformer is lower than in metropolitan areas and may result in lower PULs. In the April 2013 Standards Final Rule, DOE reduced the PUL by 10 percent for utilities serving counties with fewer than 32 households per square mile. In the June 2019 Early Assessment RFI, DOE requested comment and data on the appropriateness of this adjustment. 84 FR 28239, 28253.

HVOLT and NEMA commented that low population density results in lower PULs, as some distribution transformers serve only one customer. (HVOLT, No. 2 at p. 5; NEMA, No. 13

at p. 10) NRECA recommended retaining the adjustment factor for counties with fewer than 32 households per square mile, as many co-ops serve counties with much lower household densities. (NRECA, No. 15 at p. 3)

DOE request comment on its proposal to examine the impacts of utilities serving low populations densities as a consumer subgroup.

2.13.2 Utility Purchasers of Vault (Underground) and Subsurface Installations

DOE estimates that vault and subsurface distribution transformers[43] represent less than 2 percent of units shipped, and are typically owned and operated by utilities serving urban populations.

In response to the June 2019 Early Assessment RFI, APPA commented that since higher efficiency units are typically larger and heavier, there are many examples where the cost-effectiveness of efficiency is significantly reduced. They cite vault distribution transformers as an example for which an increase in size may result in notable costs to expand the size of the vault. (APPA, No. 16 at p. 3)

As discussed in section 2.9.3 DOE surveyed several electric utilities through an engineering firm to inquire about their installation procedures and remediation practices when a new, potentially larger, or heavier distribution transformer of the same capacity (in kVA) could not be installed in the desired location.[44] Responses to this survey indicate that the increasing volume of a replacement distribution transformer could be an issue in the future. Respondents stated that this was most acute with older vaults or subsurface enclosures where existing space for larger equipment is limited, as the enclosures were specified and installed prior to DOE energy conservation standards for distribution transformers. Respondents also stated that, with proper specification of transformer dimensions at the time of purchase, these issues can be avoided.

If needed, underground vault or subsurface enclosure renovation due to the increased transformer volume could require extensive costs due to the required labor, material, and equipment costs. As it did for the April 2013 Standards Final Rule, DOE will examine this issue as a separate subgroups analysis in the NOPR. For that analysis, DOE intends to calculate the volumes of those transformers selected by the LCC model, as a function of standard level, for the two representative units for which transformer vault installation constraints are most likely to be an issue: RU4 and RU5. DOE will examine the costs of vault enlargement as a function of increased transformer volume.

---

[43] DOE uses the term "vault distribution transformer" to mean a distribution transformer specifically designed for and installed in an underground, below-grade, vault. DOE uses the term subsurface distribution transformer to refer to a distribution transformer specifically designed for and installed in a prefabricated concrete enclosure that is buried in the ground so that the installed transformer can be accessed at grade.

[44] See appendix 8D of the TSD for details.

In the April 2013 Standards Final Rule 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. To estimate new values for fixed and variable costs DOE will examine available information contained in RSMeans data.[45]

DOE request comment on its proposed approach for vault and subsurface enclosure renovation or replacement.

APPA commented that even if there is space available, customers can experience lengthy outages while the vault is being expanded. (APPA, No. 16 at p. 3) DOE is unaware of reasons why there would be a need for vault expansion if there is adequate space to install a new transformer.

DOE requests further comment on the potential for reliability concerns related to vault expansion.

2.14 EMISSIONS ANALYSIS

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site (where applicable) combustion emissions of CO_2, NOX, SO_2, and Hg. The second component estimates the impacts of potential standards on emissions of two additional greenhouse gases, methane (“CH_4”) and nitrous oxide (“N_2O”), as well as the reductions to emissions of all species due to “upstream” activities in the fuel production chain. These upstream activities comprise extraction, processing, and transporting fuels to the site of combustion. The associated emissions are referred to as upstream emissions.

The analysis of power sector emissions uses marginal emissions factors that are derived from data in the most recent publication of AEO. The methodology is described in chapter 13 and 15 of the preliminary TSD.

Combustion emissions of CH_4 and N_2O are estimated using emissions intensity factors published by the EPA: GHG Emissions Factors Hub.[46] The FFC upstream emissions are estimated based on the methodology described in chapter 15 of the preliminary TSD. The upstream emissions include both emissions from fuel combustion during extraction, processing,

[45] Gordain, *2021 Electrical Costs Book*, 2020, <https://www.rsmeans.com/products/books/2021-electrical-costs-book>
[46] Available at: *http://www2.epa.gov/climateleadership/center-corporate-climate-leadership-ghg-emission-factors-hub*.*http://www2.epa.gov/climateleadership/center-corporate-climate-leadership-ghg-emission-factors-hub*.

and transportation of fuel, and “fugitive” emissions (direct leakage to the atmosphere) of CH_4 and CO_2.

The emissions intensity factors are expressed in terms of physical units per megawatt-hour (“MWh”) or MMBtu of site energy savings. Total emissions reductions are estimated using the energy savings calculated in the NIA.

The AEO incorporates the projected impacts of existing air quality regulations on emissions. Each AEO generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of the time of its preparation.

2.15 MONETIZATION OF EMISSIONS REDUCTION BENEFITS

DOE estimates the monetized benefits of the reductions in emissions of CO_2,CH_4, and N_2O by using a measure of the social cost ("SC") of each pollutant (e.g., SC-CO_2). These estimates represent the monetary value of the net harm to society associated with a marginal increase in emissions of these pollutants in a given year, or the benefit of avoiding that increase. These estimates are intended to include (but are not limited to) climate-change-related changes in net agricultural productivity, human health, property damages from increased flood risk, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services.

IPI recommended that DOE continue that DOE should continue to monetize the benefits the full benefits of greenhouse gas emission reductions. (IPI, No. 5 at p.1) Specifically, it recommended DOE use the Interagency Working Group (IWG) social cost of greenhouse gases estimates and look at the global perspective on climate damages, not simply the national impact. (IPI, No. 5 at p. 2-3) IPI claimed that the current interim methods under value the monetary cost of emissions and therefore DOE should use the IWG social cost of carbon, which has been used for other rulemakings and which IPI asserted remains the best tool for monetizing greenhouse gas emissions. (IPI, No. 5 at p. 3-5)

DOE used the estimates for the social cost of greenhouse gases (“SC-GHG”) from the most recent update of the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government (IWG) working group, from “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990.” (February 2021 TSD). DOE has determined that the estimates from the February 2021 TSD, as described more below, are based upon sound analysis and provide well founded estimates for DOE's analysis of the impacts of related to the reductions of emissions anticipated from the proposed rule.

The SC-GHG estimates in the February 2021 TSD are interim values developed under Executive Order (E.O.) 13990 for use until an improved estimate of the impacts of climate change can be developed based on the best available science and economics. The SC-GHG estimates used in this analysis were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, an interagency working group (IWG) that included DOE, the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO2 estimates and recommended four global values for use in regulatory analyses. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

The SC-CO2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, and recommended specific criteria for future updates to the SC-CO2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies 2017). On January 20, 2021, President Biden issued Executive Order 13990, which directed the IWG to ensure that the U.S. Government's (USG) estimates of the SC-CO2social cost of carbon and other greenhouse gases reflect the best available science and the recommendations of the National Academies (2017). The IWG was tasked with first reviewing the estimates currently used by the USG and publishing interim estimates within 30 days of E.O. 13990 that reflect the full impact of GHG emissions, including taking global damages into account, which resulted in the issuance of the February 2021 TSD. More information on the basis for the IWG's interim values may be found in the IWG's Technical Support Document.[47]

DOE uses benefit-per-ton estimates for NO_X based on data developed by EPA's Office of Air Quality Planning and Standards Environmental Benefits Mapping and Analysis Program, which has published monetized benefits related to emissions of PM2.5 and PM2.5 precursors, including NOx, from 17 sectors.[48]

2.16 UTILITY IMPACT ANALYSIS

To estimate the impacts of potential energy conservation standards on the electric utility industry, DOE used published output from the NEMS associated with the *AEO*. NEMS is a large, multi-sectoral, partial-equilibrium model of the U.S. energy sector that EIA has developed over several years, primarily for the purpose of preparing the *AEO*. NEMS produces a widely recognized forecast for the United States through 2050 and is available to the public.

DOE uses a methodology based on results published for the *AEO* Reference case, as well as a number of side cases that estimate the economy-wide impacts of changes to energy supply

[47] See Interagency Working Group on Social Cost of Greenhouse Gases, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates Under Executive Order 13990*, Washington, D.C., February 2021. (https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf?source=email)
[48] http://www2.epa.gov/benmap/sector-based-pm25-benefit-ton-estimates

and demand. DOE estimates the marginal impacts of reduction in energy demand on the energy supply sector. In principle, marginal values should provide a better estimate of the actual impact of energy conservation standards. DOE uses the side cases to estimate the marginal impacts of reduced energy demand on the utility sector. These marginal factors are estimated based on the changes to electricity sector generation, installed capacity, fuel consumption and emissions in the *AEO* Reference case and various side cases. The methodology is described in more detail in chapter 15 of the preliminary TSD.

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

2.17 EMPLOYMENT IMPACT ANALYSIS

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

Indirect employment impacts may result from expenditures shifting between goods (the substitution effect) and changes in income and overall expenditure levels (the income effect) that occur due to standards. DOE defines indirect employment impacts from standards as net jobs eliminated or created in the general economy as a result of increased spending driven by increased product prices and reduced spending on energy.

The indirect employment impacts are investigated in the employment impact analysis using the Pacific Northwest National Laboratory's "Impact of Sector Energy Technologies" ("ImSET") model.[8] The ImSET model was developed for DOE's Office of Planning, Budget, and Analysis to estimate the employment and income effects of energy-saving technologies in buildings, industry, and transportation. Compared with simple economic multiplier approaches, ImSET allows for more complete and automated analysis of the economic impacts of energy conservation investments.

2.18 REGULATORY IMPACT ANALYSIS

In the NOPR stage, if conducted, DOE prepares an analysis that evaluates potential non-regulatory policy alternatives, comparing the costs and benefits of each to those of the proposed standards. DOE recognizes that non-regulatory policy alternatives 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 potential future impacts of current initiatives.

CHAPTER 3. MARKET AND TECHNOLOGY ASSESSMENT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

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 PRODUCT 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.

The codified definition for distribution transformers based on EPACT 2005 is provided in 10 CFR 431.192. Specifically, distribution transformer is defined as a transformer that:

(1) has an input voltage of 34.5 kilovolts or less;
(2) has an output voltage of 600 volts or less;
(3) is rated for operation at a frequency of 60 Hertz; 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) uninterrupted power supply transformer; or
   (xiii) welding transformer.

3.3 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. Currently, DOE has established 11 equipment classes, using the following class-setting factors:

(a) Type of transformer insulation - liquid-immersed or dry-type,
(b) Phase count – single-phase or three-phase,
(c) Voltage class - low or medium (for dry-type units only), and
(d) Basic impulse insulation level (for medium-voltage, dry-type units only),
(e) Mining Transformers.

Insulation type refers to the medium used to electrically insulate and thermally cool a transformer’s windings. Although liquid insulations have advantages in both regards, they are viewed as less safe than dry insulation because the insulating liquid can leak and, in extreme cases, ignite. Accordingly liquid insulation is generally limited to outdoor installation. Though generally less efficient, dry-type units offer additional utility to the consumer in the form of greater safety and are, therefore, placed into separate equipment classes.

Phase count refers to the type of electrical power that the transformer can process. Most electrical 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, generally, vice versa) and, therefore, each offers distinct consumer utility.

Voltage class refers to whether a transformer's input voltage is greater than 600 ("medium") or 600 and less ("low"). The transformer input voltage selection is dictated by the application requirements and so medium- and low-voltage transformers offer distinct consumer utility.

Basic impulse insulation level (BIL) refers to how resistant a transformer is to large voltage transients (most commonly 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 application, BIL offers distinct consumer utility. Generally, greater BIL ratings carry lesser transformer operating efficiencies because the additional insulation and necessary clearances increases 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, forcing a larger core and, thus, increasing core losses. DOE has used BIL to establish equipment classes only for medium-voltage, dry-type transformers because it affects their efficiency more sharply than those of liquid-immersed and low-voltage units.

"Mining distribution transformers" are a separate equipment class for which standards have not been established. 10 CFR 431.196(d). "Mining distribution transformer" is defined at 10 CFR 431.192 as:

> A medium-voltage dry-type distribution transformer that is built only for installation in an underground mine or surface mine, inside equipment for use in an underground mine or surface mine, on-board equipment for use in an underground mine or surface mine, or for equipment used for digging, drilling, or tunneling underground or above ground, and that has a nameplate which identifies the transformer as being for this use only.

While DOE established no standards for mining transformers, it stated that it may explore standards in the future if it believed that mining transformers are being used to circumvent energy conservation standards. 75 FR 23353. DOE recognizes that mining transformers are subject to unique dimensional constraints that affect efficiency and other performance attributes. Mining transformers are further disadvantaged by the fact that they must supply power at several output voltages simultaneously. Currently, DOE has no evidence that mining transformers are being purchased to circumvent standards. DOE continues to reserve a separate equipment class for mining transformers without any energy conservation standards.

Table 3.3.1 presents the eleven equipment classes within the scope of this rulemaking analysis and provides the kVA range associated with each.

Table 3.3.1 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
EC11	Mining Transformers				

* EC = Equipment Class

3.4 PRODUCT TEST PROCEDURES

This section discusses standards relevant to the testing of distribution transformers. It covers DOE federal test procedure standards as well as trade/industry association test procedure standards. For more information about the industry associations mentioned in this section see section 3.5.

3.4.1 DOE Test Procedure

Generally, the DOE test procedure is derivative of and similar to the (defunct) NEMA TP-2. EPACT 2005 specifies that for distribution transformers for which DOE determines that energy conservation standards are warranted, the DOE test procedures must be the "Standard Test Method for Measuring the Energy Consumption of Distribution Transformers" prescribed by the National Electrical Manufacturers Association (NEMA TP 2-1998), subject to review and revision by the Secretary of Energy in accordance with certain criteria and conditions. (42 U.S.C. 6293(b)(10), 6314(a)(2)-(3) and 6317(a)(1))

The DOE test procedures for distribution transformers appear at title 10 of the Code of Federal Regulations (CFR) part 431, subpart K, appendix A. Manufacturers must use the prescribed DOE test procedure as the basis for certifying that equipment complies with applicable energy conservation standards and when making representations to the public regarding the energy use or efficiency of those types of equipment. (42 U.S.C. 6314(d))

On May 10, 2019, DOE published a notice of proposed rulemaking ("NOPR") which proposed minor revisions and clarifications to the DOE test procedure in response to stakeholder comment and updates to the industry standards on which the DOE test procedure is based. 84 FR 20704.

3.4.2 IEEE Standards

The Institute of Electronic and Electrical Engineers Inc. (IEEE) also published various standards related to distribution transformer testing. DOE reviewed IEEE's website to find standards relevant to the testing of distribution transformers. Standards for direct testing are outlined in section 3.4.2.1.

3.4.2.1 Testing Standards

- C57.12.90-2015: *Methods for performing tests specified in IEEE standard, C57.12.00 and other standards applicable to liquid-immersed distribution, power, and regulating transformers are described.*[1]

- C57.12.91-2020: *IEEE standard test code for dry-type distribution and power transformers. Updated to reflect current practice in the testing procedures of dry-type transformers, substantive changes have been made to Clause 5, Clause 7, Clause 10, Clause 11, and Clause 13 of IEEE standard C57.12.91-2011 to reflect current practice in the testing procedures of dry-type transformers.*[2]

3.4.2.2 Supporting Standards

In addition to the test standards, IEEE publishes other standards related to distribution transformers which are not test standards per se but which may house information needed to perform the procedures laid out in the testing standards. The testing-support standards include:

- C57.12.00-2015: *Electrical and mechanical requirements for liquid-immersed distribution and power transformers, and autotransformers and regulating transformers; single-phase and polyphase, with voltages of 601 V or higher in the highest voltage winding, are set forth.*[3]

- C57.12.01-2020: *Electrical, mechanical, and safety requirements of ventilated, non-ventilated, and sealed dry-type distribution and power transformers or autotransformers (single and polyphase, with a voltage of 601 V or higher in the highest voltage winding) are described in this standard.*[4]

- C57.12.35-2013: *Bar code label requirements for specific types of distribution transformers and step-voltage regulators are covered in this standard. Data content for temporary and permanent bar-code labeling is described as well as bar-code label print quality and durability requirements.*[5]

- C57.12.37-2015: *A basis for the electronic reporting of transformer test data on liquid immersed distribution transformers, as defined in the IEEE C57.12.2X, C57.12.3X, and C57.12.4X standards series, is provided in this standard.*[6]

- C57.12.58-2017: *General recommendations for measuring voltage transients in dry-type distribution and power transformers are provided. Recurrent surge voltage generator circuitry, instrumentation, test sample, test point location, mounting the test coil, conducting the test, and reporting results are covered.*[7]

- C57.12.60-2020: *A uniform method is established for determining the temperature classification for the insulation systems for dry-type power and distribution transformers by testing rather than by chemical composition.*[8]

- C57.12.70-2020: *Standard terminal markings and connections are described for single-phase and three phase distribution, power, and regulating transformers. For terminal markings, it covers sequence designation, external terminal designation, neutral terminal designation, grounded terminal designation, and marking of full and tap winding terminals.*[9]

- C57.135-2011: *Adopted as IEC 62032:2012. Theory, application of phase-shifting transformers, and the difference of specification and testing to standard system transformers are described in this guide.*[10]

- C57.154-2012*: IEEE standard for the design, testing, and application of liquid-immersed distribution, power, and regulating transformers using high-temperature insulation systems and operating at elevated temperatures*.[11]

3.4.3 IEC Standards

Whereas IEEE standards still prevail in the US, the distribution transformers industry is globalized and manufacturers commonly participate in both foreign and domestic markets. Outside of the US, industry practice is more commonly governed by standards published by The International Electrotechnical Commission ("IEC"). The IEC has established the following standards relevant to the testing of power[a] transformers.[12]

- IEC 60076-1: *Standards for power transformers in general*.

- IEC 60076-2: *Standards for measuring temperature rise for liquid immersed transformers*.

- IEC 60076-3: *Standards for insulation levels, dielectric tests, and external clearances in air.*

---

[a] IEC defines a power transformer as, "A static piece of apparatus with two or more windings which, by electromagnetic induction, transforms a system of alternating voltage and current into another system of voltage and current usually of different values and at the same frequency for the purpose of transmitting electrical power." This definition includes what DOE defines as distribution transformers.

- IEC 60076-5: *Standards for measuring the ability to withstand short circuit.*
- IEC 60076-7: *Loading guide for oil-immersed power transformers*.
- IEC 60076-10: *Standards for determining sound levels*.
- IEC 60076-11: *Standards for dry-type transformers*.
- IEC 60076-12: *Loading guide for dry-type transformers*.

3.5 INDUSTRY ASSOCIATIONS

The National Electrical Manufacturers Association ("NEMA") represents nearly 325 electrical equipment and medical imaging manufacturers, including manufacturers of distribution transformers. NEMA provides lobbying service, technical papers, white papers, application guides, and standards for the products it covers.[13] For more information on the NEMA distribution transformer standards see section 3.9.

IEEE is the world's largest technical professional organization for the advancement of technology, consisting of more than 423,000 members spanning over 160 countries.[14] IEEE creates an environment for stakeholders in the distribution transformers industry to collaborate and engage in coordinated public policy. IEEE also holds conferences, issues publications, provides education, and sets standards (see section 3.4) for the distribution transformers industry.

IEC is the world's leading organization for the preparation and publication of International Standards for all electrical, electronic and related technologies. The IEC provides an international platform for companies, industries, and governments to discuss, deliberate, and define standards that they deem relevant.[15] The American National Standards Institute ("ANSI") coordinates US standards with international standards.[16] ANSI is the official US representative to the IEC through the U.S National Committee ("USNC"). Over the past decade the US has gradually increased its adoption of IEC standards.[17]

3.6 MANUFACTURER INFORMATION

3.6.1 Major Manufacturers

DOE found 27 companies that manufacture and sell distribution transformers in the U.S market. DOE used the market assessment information from the last rulemaking to determine manufacturers responsible for 80% of US domestic sales, described as major manufacturers. DOE identified 15 of these major manufacturers of liquid-immersed and dry-type distribution transformers:

3.6.1.1 Liquid-Immersed

- Hitachi ABB Power Grids: *Hitachi, a publicly traded multinational conglomerate, purchased ABB Power Grids in 2020 and formed Hitachi ABB Power Grids. The new entity is headquartered in Switzerland.*[18]

- Arkansas Electric Cooperatives, Inc. (AECI): *AECI owns Electric Research and Manufacturing Cooperative, Inc (ERMCO), an oil filled transformer manufacturer based in Tennessee*.[19]

- Eaton Corporation: *A multinational power management company headquartered in Ireland. Eaton owns Cooper Power Systems, a global manufacturer of power delivery equipment*.[20]

- Howard Industries Advanced Technology Corporation: *A private company that manufactures industrial and electric apparatus and equipment and is based in Mississippi*.[21]

- Spire Power Solutions: Spire Power Solutions owns Power Partners, *a manufacturer of liquid-immersed distribution transformers based in Georgia*.[22] Also sells under brand "Pioneer Transformers."

- Prolec-GE: *A joint venture between Xignux, a Mexican consortium, and General Electric (GE), a US multinational conglomerate. Prolec-GE is a manufacturer of liquid-immersed distribution transformers based in Mexico.*[23]

3.6.1.2 Low-Voltage, Dry-Type

For low-voltage dry-type distribution transformers, the seven major manufacturers are:

- Eaton Corporation: *A multinational power management company headquartered in Ireland. Eaton owns Cooper Power Systems, a global manufacturer of power delivery equipment*.

- Electro-Mechanical Corporation: *A family-owned company manufacturing electrical apparatus based in Virginia. Its divisions Line Power and Federal Pacific Power manufacture power distribution components, including distribution transformers*.[24]

- Hammond Power Solutions Inc (HPS): *A public company that manufactures transformers and power delivery products headquartered in Ontario, Canada*.[25]

- Hubbell Incorporated: *A public company that manufactures electrical and electronic products for non-residential and residential construction, industrial, and utility applications. It is headquartered in Connecticut*.[26]

- Olsun Electrics Corporation: *A private company that manufactures transformers. It is based in Illinois*.[27]

- Prolec GE: *A joint venture between Xignux, a Mexican consortium, and General Electric (GE), a US multinational conglomerate. Prolec-Ge is a manufacturer of distribution transformers based in Mexico.*

- Schneider Electric SE: *A public multinational company that manufactures equipment for energy management and industrial automation, headquartered in France*.[28]

3.6.1.3 Medium-Voltage, Dry-Type

- Hitachi ABB Power Grids: *Hitachi, a publicly traded multinational conglomerate, purchased ABB Power Grids in 2020 and formed Hitachi ABB Power Grids. The new entity is headquartered in Switzerland.*

- Electro-Mechanical Corporation: *A family-owned company manufacturing electrical apparatus based in Virginia. Its divisions Line Power and Federal Pacific Power manufacture power distribution components, including distribution transformers.*

- Hammond Power Solutions Inc (HPS): *A public company that manufactures transformers and power delivery products headquartered in Ontario, Canada.*

- JST Power Equipment: *A private company primarily engaged in manufacturing transformers. It is based in China*.[29]

- MGM Transformer Company: *A private company that manufactures transformers. It is based in California.*[30]

- SBG-USA: *A subsidiary of SGB-SMIT Group that manufactures transformers in the U.S. They are a sister company to OTC Services who repairs distribution transformers. Both SGB-USA and OTC Services are based in Ohio.*[31]

- Olsun Electrics Corporation: *A private company that manufactures transformers. It is based in Illinois.*

3.6.2 Small Business Impacts

DOE considers the possibility of small businesses being disproportionately impacted by the promulgation of energy conservation standards for distribution transformers. The Small Business Association ("SBA") considers an entity to be a small business if, together with its affiliates, it employs less than a threshold number of workers specified in 13 CFR part 121, which relies on size standards and codes established by the North American Industry Classification System ("NAICS"). The threshold number for NAICS classification for 335311, which applies to *Power, Distribution, and Specialty Transformers,* [32] is 750 employees.[33]

In total, there are 10 small manufacturers of distribution transformers operating in the U.S. today.

There are 2 small manufacturers that make liquid-immersed distribution transformers: Central Moloney, Inc. and Maddox Industrial Transformer.

There are 7 small manufacturers that make low-voltage dry-type distribution transformers: Electro-Mechanical Corporation, GFSF Inc., Hitran Corporation, Olsun Electrics Corporation, and Sola Hevi Duty Incorporated.

There are 4 small manufactures that make only medium-voltage dry-type distribution transformers: Hitran Corporation, Mag-Tran, MGM Transformer Company, and Olsun Electrics Corporation.

3.6.3 Distribution Channels

A schematic of the distribution transformer market is shown in Figure 3.6.1**Error! Reference source not found.**.[34] 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.

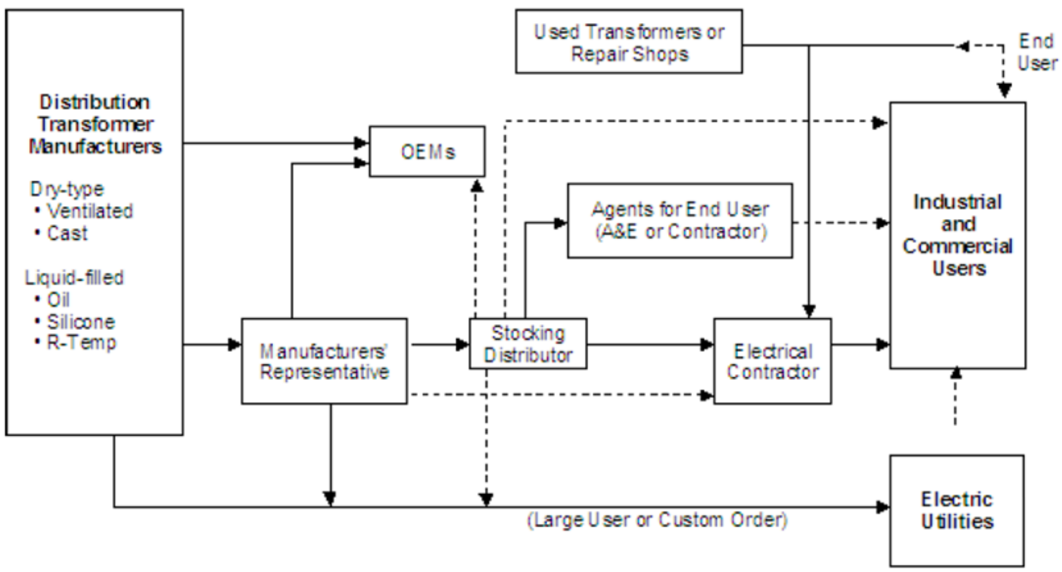


Figure 3.6.1 Market Delivery Channels for Distribution Transformers

The market delivery channel for electric utilities is generally direct, with most 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.[34] 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

Following the energy price shocks of the 1970s, utilities have used total owning cost (TOC) evaluation formulas (Eq. 3.1), 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,

$$TOC = (NL \times A) + (LL \times B) + Price \qquad \textbf{Eq. 3.1}$$

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 leveled fixed charge rate, the peak responsibility factor, the transformer loss factor, and the equivalent annual peak load.[35]

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.[34] 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 for long enough to 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 is aware that some utilities have deemphasized the importance of A and B factors and placed more emphasis on lower first costs because of the minimum efficiency standards. Many utilities still maintain 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. Similarly, utilities have found that the benefits of maintaining updated A and B factors is not worth the effort and instead rely on DOE's efficiency standards to ensure that they are getting a sufficiently efficient distribution transformer.

The medium-voltage, dry-type transformer market, like the liquid-immersed market, has manufacturers receiving 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.[34]

3.8 REGULATORY FORCES

The current U.S. DOE standards were established on April 18, 2013 and includes efficiency standards for low-voltage dry-type, medium-voltage dry-type and liquid immersed distribution transformers. At the international level, DOE is aware of standards in both Canada and Mexico that may impact the companies servicing the North American market. In addition, DOE is also aware of recent updates to U.S. import duties for aluminum and steel articles, which are major components of distribution transformers. Summaries of these regulatory forces are provided in this section.

3.8.1 U.S. Department of Energy

The U.S. federal government regulates efficiency for dry-type and liquid-immersed distribution transformers. The current U.S. DOE energy efficiency standards can be found in the code of federal regulations (CFR), specifically in 10 CFR 431.96. The efficiency standards for low-voltage dry-type and liquid immersed distribution transformers are determined based on whether the transformer is single-phase or three-phase, in addition to the transformer's kVA. For medium-voltage dry-type distribution transformers however, the standards are not only based on its kVA and whether the transformer is single-phase or three-phase, but also the BIL. Table 3.8.1

through Table 3.8.3 provide the energy conservation standards and their effective dates for distribution transformers.

Table 3.8.1 DOE Energy Conservation Standards for Low-Voltage, Dry-type Distribution Transformers manufactured on or after January 1, 2016

Single-Phase		Three-Phase	
kVA	**Efficiency (%)**	**kVA**	**Efficiency (%)**
15	97.70	15	97.89
25	98.00	30	98.23
37.5	98.20	45	98.40
50	98.30	75	98.60
75	98.50	112.5	98.74
100	98.60	150	98.83
167	98.70	225	98.94
250	98.80	300	99.02
333	98.90	500	99.14
		750	99.23
		1000	99.28

Note: All efficiency values are at 35 percent of nameplate-rated load, determined according to the DOE Test Method for Measuring the Energy Consumption of Distribution Transformers under Appendix A to Subpart K of 10 CFR part 431.

Table 3.8.2 DOE Energy Conservation Standards for Liquid-immersed Distribution Transformers manufactured on or after January 1, 2016

Single-Phase		Three-Phase	
kVA	**Efficiency (%)**	**kVA**	**Efficiency (%)**
10	98.70	15	98.65
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1000	99.43
667	99.52	1500	99.48
833	99.55	2000	99.51
		2500	99.53

Note: All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test Method under Appendix A to Subpart K of 10 CFR part 431.

Table 3.8.3 DOE Energy Conservation Standards for Medium-Voltage, Dry-type Distribution Transformers manufactured on or after January 1, 2016

Single-Phase				Three-Phase			
	BIL				BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.10	97.86	-	15	97.50	97.18	-
25	98.33	98.12	-	30	97.90	97.63	-
37.5	98.49	98.30	-	45	98.10	97.86	-
50	98.60	98.42	-	75	98.33	98.13	-
75	98.73	98.57	98.53	112.5	98.52	98.36	-
100	98.82	98.67	98.63	150	98.65	98.51	-
167	98.96	98.83	98.80	225	98.82	98.69	98.57
250	99.07	98.95	98.91	300	98.93	98.81	98.69
333	99.14	99.03	98.99	500	99.09	98.99	98.89
500	99.22	99.12	99.09	750	99.21	99.12	99.02
667	99.27	99.18	99.15	1000	99.28	99.20	99.11
833	99.31	99.23	99.20	1500	99.37	99.30	99.21
				2000	99.43	99.36	99.28
				2500	99.47	99.41	99.33

Note: All efficiency values are at 50 percent of nameplate rated load, determined according to the DOE Test Method under Appendix A to Subpart K of 10 CFR part 431.

3.8.2 Canada

The Canadian Government currently regulates efficiency of dry-type transformers but does not regulate efficiency of liquid-immersed transformers. For transformers manufactured on or after January 1, 2016, the dry-type transformer regulation mandates compliance with efficiency values for 20-199 kV BIL single- and three-phase transformers at 35 percent nominal load. The current testing standard is the DOE test method under Appendix A to Subpart K of 10 CFR part 431. Liquid-immersed distribution transformers are addressed by a voluntary program, which has been drafted to allow supervisory oversight by the NRCan.

Besides federal regulations, there are also provincial energy efficiency regulations for distribution transformers. Specifically, energy efficiency and testing standards for liquid-filled transformers are regulated in Ontario, New Brunswick and Nova Scotia, while energy efficiency and testing standards for dry-type transformers are regulated in the same aforementioned provinces, in addition to Quebec.

3.8.2.1 Liquid-Immersed Distribution Transformer Standards

Federal-NRCan Regulations

Canada currently does not regulate efficiency for liquid-immersed distribution transformers. However, 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.

In the NRCan Forward Regulatory Plan 2018-2020, liquid-filled transformers were being considered as a "new product category" for future amendments to the regulation. However, liquid-filled transformers were not included in the proposed Amendment 17 in May 2021.[36]

Provincial – Ontario Regulations

Ontario requires liquid-filled distribution transformers manufactured between March 1, 2004 and December 31, 2022 to be subject to testing standard CSA C802.1-13 and the associated minimum efficiency values.[37] However, beginning January 1, 2023, liquid-filled distribution transformers will align with the U.S. regulations and distribution transformers will be subject to the scope, testing standard, and minimum efficiency requirements at 10 CFR part 431.192, 431.193, and 431.196.[37]

Provincial – New Brunswick Regulations

New Brunswick currently regulates liquid-filled distribution transformers that are single- and three-phase, at 60 Hz, and rated at 10 to 833 kVA for single-phase and 15 to 3000 kVA for three-phase, with an insulation class of 34.5 kV and less.[38] For transformers manufactured starting August 31, 2004 until June 1, 2012, New Brunswick regulations requires complying with testing standard CSA C802.1-00, with efficiency regulations prescribed in clause 7 and table 1 of the testing standard. For transformers manufactured starting June 1, 2012, New Brunswick regulations requires complying with testing standard CAN/CSA C802.1-00 (as reaffirmed in 2011), with efficiency regulations prescribed in clause 7 and table 1 of the testing standard (as reaffirmed in 2011).

Provincial – Nova Scotia Regulations

Similar to New Brunswick, Nova Scotia currently regulates liquid-filled distribution transformers that are single- and three-phase, at 60 Hz, and rated at 10 to 833 kVA for single-phase and 15 to 3000 kVA for three-phase, with an insulation class of 34.5 kV and less.[39] For transformers manufactured on or after January 1, 2008, Nova Scotia regulations requires complying with testing standard CAN/CSA C802.1-00, with efficiency regulations prescribed in clause 7 and table 1 of the testing standard.

3.8.2.2 Dry-Type Transformer Standards

Federal – NRCan Regulations

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 were included in NEMA TP 1 or the DOE's rulemaking on distribution transformers.

In September 2011, NRCan published another amendment for the minimum efficiency requirements. The amendment resulted in increasing the standard levels for single and three-phase dry-type transformers with a BIL of 20-150 kV, increasing the scope to include transformers with a BIL up to 199 kV, removed the exclusion for instrument transformers, and provided new exceptions for special impedance transformers, grounding transformers, resistance grounding transformers and on-load regulating transformers.

On April 30, 2016, NRCan published a notice of intent to amend the Energy Efficiency Act via amendment 14 to align the minimum energy efficiency standards for dry type transformers to the amended DOE energy efficiency standards finalized in April 2013. The alignment would be considered as increasing the stringency of efficiency standards for three-phase dry type transformers in Canada. If implemented, this proposal would ensure energy efficiency standards are aligned with regulations for similar size units in the U.S. NRCan proposes that the updated standards will apply to dry-type transformers that have been manufactured on or after January 1, 2016. These new energy efficiency standards became effective in 2019. In addition, NRCan also proposed that CSA C802.2-12, *Minimum efficiency values for dry-type transformers* be referenced as the energy performance test procedure.

	Percentage efficiency at 35% nominal load	**Percentage efficiency at 50% nominal load**		
Single-phase kVA rating	**Voltage = 1.2 kV**	**Voltage > 1.2 kV**		
		20-45kV BIL	**46-95kV BIL**	**96-199kV BIL**
15	97.70	98.10	97.86	97.6
25	98.00	98.33	98.12	97.9
37.5	98.20	98.49	98.30	98.10
50	98.30	98.60	98.42	98.20
75	98.50	98.73	98.57	98.53
100	98.60	98.82	98.67	98.63
167	98.70	98.96	98.83	98.80
250	98.80	99.07	98.95	98.91
333	98.90	99.14	99.03	98.99
500	-	99.22	99.12	99.09
667	-	99.27	99.18	99.15
833	-	99.31	99.23	99.20
Three-phase kVA rating	**Voltage = 1.2 kV**	**Voltage > 1.2 kV**		
		20-45kV BIL	**46-95kV BIL**	**96-199kV BIL**
15	97.89	97.5	97.18	96.8

30	98.23	97.9	97.63	97.3
45	98.4	98.1	97.86	97.6
75	98.6	98.33	98.13	97.9
112.5	98.74	98.52	98.36	98.1
150	98.83	98.65	98.51	98.2
225	98.94	98.82	98.69	98.57
300	99.02	98.93	98.81	98.69
500	99.14	99.09	98.99	98.89
750	99.23	99.21	99.12	99.02
1,000	99.28	99.28	99.2	99.11
1,500	-	99.37	99.3	99.21
2,000	-	99.43	99.36	99.28
2,500	-	99.47	99.41	99.33
3,000	-	99.47	99.41	99.33
3,750	-	99.47	99.41	99.33
5,000	-	99.47	99.41	99.33
7,500	-	99.48	99.41	99.39

presents the current minimum efficiency requirements for dry-type transformers. A dry-type transformer is described as follows:

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

- is either single phase with a nominal power of 15 to 833 kVA, or three-phase with a nominal power of 15 to 7500 kVA
- has a nominal frequency of 60 Hz, and
- has high voltage winding of 35 kV or less

but does not include:

- an auto transformer
- a drive (isolation) transformers with two or more output windings or a nominal low-voltage line current greater than 1500 A
- a grounding transformer
- a rectifier transformer
- a sealed transformer
- a non-ventilated transformer
- a testing transformer
- a furnace transformer
- a welding transformer

- a special impedance transformer
- a transformer with a nominal low-voltage line current of 4000 A or more
- an on-load regulating transformer, or
- a resistance grounding transformer

Table 3.8.4 Canadian Minimum Efficiency Standards for Dry-type Transformers

	Percentage efficiency at 35% nominal load	Percentage efficiency at 50% nominal load		
Single-phase kVA rating	**Voltage = 1.2 kV**	**Voltage > 1.2 kV**		
		20-45kV BIL	**46-95kV BIL**	**96-199kV BIL**
15	97.70	98.10	97.86	97.6
25	98.00	98.33	98.12	97.9
37.5	98.20	98.49	98.30	98.10
50	98.30	98.60	98.42	98.20
75	98.50	98.73	98.57	98.53
100	98.60	98.82	98.67	98.63
167	98.70	98.96	98.83	98.80
250	98.80	99.07	98.95	98.91
333	98.90	99.14	99.03	98.99
500	-	99.22	99.12	99.09
667	-	99.27	99.18	99.15
833	-	99.31	99.23	99.20
Three-phase kVA rating	**Voltage = 1.2 kV**	**Voltage > 1.2 kV**		
		20-45kV BIL	**46-95kV BIL**	**96-199kV BIL**
15	97.89	97.5	97.18	96.8
30	98.23	97.9	97.63	97.3
45	98.4	98.1	97.86	97.6
75	98.6	98.33	98.13	97.9
112.5	98.74	98.52	98.36	98.1
150	98.83	98.65	98.51	98.2
225	98.94	98.82	98.69	98.57
300	99.02	98.93	98.81	98.69
500	99.14	99.09	98.99	98.89
750	99.23	99.21	99.12	99.02
1,000	99.28	99.28	99.2	99.11
1,500	-	99.37	99.3	99.21
2,000	-	99.43	99.36	99.28
2,500	-	99.47	99.41	99.33
3,000	-	99.47	99.41	99.33

3,750	-	99.47	99.41	99.33
5,000	-	99.47	99.41	99.33
7,500	-	99.48	99.41	99.39

3.8.3 Mexico

Mexico is one of the regional leaders in promoting and regulating energy efficient transformers. Mexico began regulating distribution transformers when it enacted NOM-J116 in 1977.[40] 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 DOE) 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.[41] 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. In 2014, NOM-002 was revised to NOM-002-SEDE/ENER-2014, which was approved on August 8, 2014. Pedestal transformers covered by NMX-J-285-ANCE-2013, submersible transformers covered by NMX-J-287-ANCE-1998 and pole transformers covered by NMX-J-116-ANCE-2005 will be required to comply with the short circuit specifications established under point 5.8 of Mexican Norm NMX-J-116-ANCE-2005. In addition, transformers must be built with a hermetic tank in order to preserve their insulating liquid. The test standard required to comply with the standards is NMX-J-169-ANCE-2004. The new requirements, which replaced the standards established under NOM-002-SEDE-2010, entered into force on December 29, 2015.[42]

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 3.8.5 presents the characteristics of regulated distribution transformers in Mexico.

Table 3.8.5 Characteristic of Regulated Distribution Transformers in Mexico

Characteristic	Specification
Power Supply	Single-phase Three-phase
Nominal Capacity	10 to 167 kVA (single-phase) 15 to 500 kVA (three-phase)
Insulation Class	Up to 95 kV BIL (Class 15 kV) Up to 150 kV BIL (Class 18 and 25 kV) Up to 200 kV BIL (Class 34.5 kV)
Installation Application	Pad; Pole; Substation; Submersible; Pedestal
Status of Transformer	Newly purchased Repaired/Refurbished

NOM-002-SEDE/ENER-2014 provides two sets of tables with the specified minimum efficiency levels and the unit losses in watts, both tested at 80 percent of nameplate load. Since the requirements in NOM-002 are based on 80 percent loading, they are not directly comparable to DOE's efficiency standards. Table 3.8.6 and Table 3.8.7 show the efficiency requirements under NOM-002.

Table 3.8.6 Minimum Efficiency Levels for Distribution 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	10	98.61	98.49	98.28
	15	98.75	98.63	98.43
	25	98.90	98.79	98.63
	37.5	98.99	98.90	98.75
	50	99.08	98.99	98.86
	75	99.21	99.12	99.00
	100	99.26	99.16	99.06
	167	99.30	99.21	99.13
Liquid-immersed, Three-phase	15	98.32	98.18	98.03
	30	98.62	98.50	98.35
	45	98.72	98.60	98.48
	75	98.86	98.75	98.64
	112.5	98.95	98.85	98.76
	150	99.03	98.94	98.86
	225	99.06	98.96	98.87
	300	99.11	99.02	98.92
	500	99.20	99.11	99.03

Note: These efficiency levels are applicable at 80 percent of nameplate load, and do not include losses from protective accessories.

Table 3.8.7 Maximum Allowed Total Losses for Distribution Transformers in Mexico

Type	Capacity [kVA]	Total Losses		
		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	10	113	123	140
	15	152	167	191
	25	222	245	278
	37.5	306	334	380
	50	371	408	461
	75	478	533	606
	100	596	678	759
	167	942	1064	1173
Liquid-immersed, Three-phase	15	205	222	241
	30	336	365	403
	45	467	511	556
	75	692	759	827
	112.5	955	1047	1130
	150	1175	1286	1384
	225	1708	1892	2057
	300	2155	2375	2620
	500	3226	3592	3918

Note: These losses are applicable at 80 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.

3.8.4 European Union

The EU’s Commission Regulation No 548/2014[43] establishes eco-design requirements for transformers with a minimum power rating of 1kVA that are used in 50Hz electricity transmission and distribution networks or for industrial applications. Distribution transformers are covered under the EU Commission's medium power transformers category which covers transformer with a highest voltage for equipment higher than 1,1 kV, but transformers not exceeding 36 kV and a rated power equal to or higher than 5 kVA but lower than 40 MVA. Table 3.8.8, Table 3.8.9, and Table 3.8.10 show the maximum load requirements for these transformers.

On October 1, 2019, the EU's commission regulation 2019/1783[44] confirmed that the Tier 1 regulations were improving the efficiency of power transformers and were being met without difficulty. It amended the regulations to permit certain exceptions for space constrained applications and Minimum Peak Efficiency Index requirements for some transformers.

Table 3.8.8 EU Requirements for Three-Phase Medium Power Transformers with Rated Power ≤ 3150 kVA

	Tier 1 (from 1 July 2015)		**Tier 2 (from 1 July 2021)**	
Rated Power (kVA)	**Maximum load losses Pk (W) (1)**	**Maximum no-load losses Po (W) (1)**	**Maximum load losses Pk (W) (1)**	**Maximum no-load losses Po (W) (1)**
≤ 25	Ck (900)	Ao (70)	Ak (600)	Ao – 10 % (63)
50	Ck (1100)	Ao (90)	Ak (750)	Ao – 10 % (81)
100	Ck (1750)	Ao (145)	Ak (1250)	Ao – 10 % (130)
160	Ck (2350)	Ao (210)	Ak (1750)	Ao – 10 % (189)
250	Ck (3250)	Ao (300)	Ak (2350)	Ao – 10 % (270)
315	Ck (3900)	Ao (360)	Ak (2800)	Ao – 10 % (324)
400	Ck (4600)	Ao (430)	Ak (3250)	Ao – 10 % (387)
500	Ck (5500)	Ao (510)	Ak (3900)	Ao – 10 % (459)
630	Ck (6500)	Ao (600)	Ak (4600)	Ao – 10 % (540)
800	Ck (8400)	Ao (650)	Ak (6000)	Ao – 10 % (585)
1000	Ck (10500)	Ao (770)	Ak (7600)	Ao – 10 % (693)
1250	Bk (11000)	Ao (950)	Ak (9500)	Ao – 10 % (855)
1600	Bk (14000)	Ao (1200)	Ak (12000)	Ao – 10 % (1080)
2000	Bk (18000)	Ao (1450)	Ak (15000)	Ao – 10 % (1305)
2500	Bk (22000)	Ao (1750)	Ak (18500)	Ao – 10 % (1575)
3150	Bk (27500)	Ao (2200)	Ak (23000)	Ao – 10 % (1980)

Table 3.8.9 EU Maximum Load and No-Load Losses (in W) for Three –Phase Dry-Type Medium Power Transformers with one Winding with Um ≤ 24 kV and the Other one with Um ≤ 1.1 kV

	Tier 1 (1 July 2015)		Tier 2 (1 July 2021)	
Rated Power (kVA)	**Maximum load losses Pk (W) (2)**	**Maximum no-load losses Po (W) (2)**	**Maximum load losses Pk (W) (2)**	**Maximum no-load losses Po (W) (2)**
≤ 50	Bk (1700)	Ao (200)	Ak (1500)	Ao – 10 % (180)
100	Bk (2050)	Ao (280)	Ak (1800)	Ao – 10 % (252)
160	Bk (2900)	Ao (400)	Ak (2600)	Ao – 10 % (360)
250	Bk (3800)	Ao (520)	Ak (3400)	Ao – 10 % (468)
400	Bk (5500)	Ao (750)	Ak (4500)	Ao – 10 % (675)
630	Bk (7600)	Ao (1100)	Ak (7100)	Ao – 10 % (990)
800	Ak (8000)	Ao (1300)	Ak (8000)	Ao – 10 % (1170)
1000	Ak (9000)	Ao (1550)	Ak (9000)	Ao – 10 % (1395)
1250	Ak (11000)	Ao (1800)	Ak (11000)	Ao – 10 % (1620)
1600	Ak (13000)	Ao (2200)	Ak (13000)	Ao – 10 % (1980)
2000	Ak (16000)	Ao (2600)	Ak (16000)	Ao – 10 % (2340)
2500	Ak (19000)	Ao (3100)	Ak (19000)	Ao – 10 % (2790)
3150	Ak (22000)	Ao (3800)	Ak (22000)	Ao – 10 % (3420)

Table 3.8.10 EU Requirements for Medium Power Pole-Mounted Transformers

	Tier 1 (1 July 2015)		Tier 2 (1 July 2021)	
Rated Power (kVA)	**Maximum load losses (in W) (3)**	**Maximum no-load losses (in W) (3)**	**Maximum load losses (in W) (3)**	**Maximum no-load losses (in W) (3)**
25	Ck (900)	Ao (70)	Bk (725)	Ao (70)
50	Ck (1100)	Ao (90)	Bk (875)	Ao (90)
100	Ck (1750)	Ao (145)	Bk (1475)	Ao (145)
160	Ck + 32 % (3102)	Co (300)	Ck + 32 % (3102)	Co – 10 % (270)
200	Ck (2750)	Co (356)	Bk (2333)	Bo (310)
250	Ck (3250)	Co (425)	Bk (2750)	Bo (360)
315	Ck (3900)	Co (520)	Bk (3250)	Bo (440)

3.8.5 U.S. Import Duties of 2018

Beginning in 2018, the US government instituted a series of import duties on, among other items, aluminum and steel articles. Steel and aluminum articles were generally subject to respective import duties of 25% and 10% *ad valorem*[b]. 83 FR 11619; 83 FR 11625.

Goods subject to tariffs are identified by their designations in the Harmonized Tariff Schedule of the United States.[45] Some of the goods subject to aluminum and steel tariffs are listed in Table 3.8.11 and

[b] *Ad valorem* tariffs are assessed in proportion to an item's monetary value.

Table 3.8.12.

Table 3.8.11 Tariff Applicability by Harmonized Tariff Schedule Code, Aluminum

HTS Designation - Aluminum	Description
7601	Unwrought
7604	Bars, Rods, Profiles
7605	Wire
7606,7	Plate, Sheet, Strip, Foil
7608,9	Tubes, Pipes, Associated Fittings
7616.99.51.60,.70	Castings and Forgings

Table 3.8.12 Tariff Applicability by Harmonized Tariff Schedule Code, Steel

HTS Designation - Steel	Description
7208-12;7225,6	Flat-rolled Products
7213-15,27,28	Bars and Rods
7216, except .61.00, .69.00, .91.00	Sections
7304-6	Tubes, Pipes, Hollow Profiles
7206,7;7224	Ingots, Other Primary Forms, Semi-finished Products
7218-23	Stainless

Since March 2018, several presidential proclamations have created or modified steel and aluminum tariffs, including changes to the products covered, countries subject to the tariffs, exclusions, etc.[46] Given the recency of several publications, combined with the supply chain disruptions caused by the Covid-19 pandemic, many of the price effects that, directly or indirectly, impact the pricing of distribution transformers may still be in flux. It may be more complicated than simply adding the tariff weighted by the fraction of steel that is imported from affected nations as manufacturers respond by substituting for other goods. Changes to business practices such as increased importation of finished products not subject to tariff may be another possible response to tariffs that affects market average pricing. On May 19, 2020, the U.S. Department of Commerce opened an investigation into the potential circumvention of tariffs via imports of finished distribution transformer cores and lamination but has not yet released the results of that investigation and no trade action has been taken. 85 FR 29926

DOE's investigation concluded that the impact of these tariffs could vary depending on individual manufacturer's supply chains and location of their production facilities. In this preliminary analysis, DOE added a partial tariff impact and conducted sensitivities for alternative tariff scenarios as discussed in chapter 5 of this TSD.

3.9 VOLUNTARY PROGRAMS

DOE reviewed several voluntary programs promoting efficient distribution transformers in the United States. In this section, DOE summarizes several voluntary programs that are still operating, and several programs that are inactive. These include the NEMA TP 1 Standard, NEMA Premium Program, the U.S. Environmental Protection Agency's Energy Star Transformers program, the Consortium for Energy Efficiency's Commercial and Industrial Transformers Initiative, and the Federal Energy Management Program.

3.9.1 National Electrical Manufacturers Association TP 1 Standard

The NEMA TP 1 standard established a voluntary efficiency standard for distribution transformers. 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). Because mandatory federal standards now exceed the requirements of NEMA TP 1, NEMA TP 1 standard has since been rescinded. https://www.nema.org/Standards/Pages/Guide-for-Determining-Energy-Efficiency-for-Distribution-Transformers.aspx.

3.9.2 National Electrical Manufacturers Association – NEMA Premium Program

The NEMA Premium program, which is no longer maintained, established a voluntary efficiency standard for low-voltage, dry-type distribution transformers. It encompassed both single- and three-phase low-voltage, dry-type units. For a low-voltage, dry-type distribution transformer to qualify as NEMA Premium, the program required that the transformer have 30 percent fewer losses than existing DOE regulations for low-voltage dry-type distribution transformers. However, this program is no longer active and has now been replaced by the mandatory DOE energy conservation standards. http://www.nema.org/Technical/Pages/NEMA-Premium-Efficiency-Transformers-Program.aspx.

3.9.3 Energy Star Transformers

In the past, 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 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 minimum efficiency standard for low-voltage dry-type transformers that were equivalent to the Energy Star level, which were in turn equivalent to the NEMA TP 1 efficiency levels. For more information or questions about this program, please contact the U.S. EPA telephone: 1-888-STAR-YES or visit https://www.energystar.gov/products/transformers.

More recently, an Energy Star specification for liquid-immersed distribution transformers was under development. The latest publication from Energy Star is the Distribution Transformers final draft specification published on December 9, 2016, which includes the cover memo, draft final specification, and a comment response document. In the cover memo, EPA stated that they were not going to finalize the specification and instead pilot a program that will provide buying guidance and web resources designed to connect utilities with manufacturers offering more efficient distribution transformers. Through the pilot, EPA intends to get a better understanding of how the distribution transformer efficiency criteria can be effectively leveraged to advance energy efficient transformers in tandem with the total cost of ownership approach to purchasing. Accordingly, EPA also posted the latest version of the draft specification, which specifies efficiency criteria based on the total owning cost and the percentage energy savings over the minimum DOE-compliant design (described as the “energy savings at optimized load factor”), which EPA intends to use as a resource for the forthcoming buying guidance. The corresponding documents for this development can be found on the following Energy Star website: https://www.energystar.gov/products/spec/distribution_transformers_pd. The buying guide for avoiding distribution transformer energy waste can also be found on the energy star website: https://www.energystar.gov/products/avoiding_distribution_transformer_energy_waste.

3.10 HISTORICAL SHIPMENTS

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. 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 during the period leading up to publication of the April 2013 standards final rule, 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. DOE then adjusted estimates of shipments to the 2019 market.

Table 3.10.1 presents the actual shipment estimates by.

Table 3.10.1 National Distribution Transformer Shipment Estimates for 2021

	Equipment Class	Units Shipped	Capacity Shipped (MVA)
1	Liquid-immersed, medium-voltage, single-phase	754,357	29,170
2	Liquid-immersed, medium-voltage, three-phase	54,891	33,573
3	Dry-type, low-voltage, single-phase	20,119	735
4	Dry-type, low-voltage, three-phase	234,684	17,900
5	Dry-type, medium-voltage, single-phase, 20–45 kV BIL*	804	26
6	Dry-type, medium-voltage, three-phase, 20–45 kV BIL	592	292
7	Dry-type, medium-voltage, single-phase, 46–95 kV BIL	619	26
8	Dry-type, medium-voltage, three-phase, 46–95 kV BIL	2,352	4,146
9	Dry-type, medium-voltage, single-phase, ≥ 96 kV BIL	229	10
10	Dry-type, medium-voltage, three-phase, ≥ 96 kV BIL	1,459	2,502

* BIL = basic impulse insulation level.

The liquid-immersed transformer market accounted for 716 percent of the distribution transformers sold in the United States in 2021 (on a unit basis). These transformers accounted for 71 percent of the distribution transformer capacity measured in 2021. 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 (by a factor of 20) than the three-phase units, which are more than 46 percent of the total MVA capacity shipped of liquid-immersed distribution transformers in 2021.

In the dry-type market, low-voltage, three-phase distribution transformers dominate, accounting for 92 percent of units and nearly 96 percent of MVA shipped. Medium-voltage, three-phase units accounted for only 73 percent of the units shipped but 99 percent of MVA shipped in 2021. Low-voltage, single-phase units totaled almost 8 percent of the units shipped; however, because their kVA ratings tend to be small (by a factor of 16) relative other low-voltage dry-type transformers, they accounted for only about 4 percent of MVA shipped in 2021. Medium-voltage, single-phase units form a small part of 2021 shipments, representing 27 percent of units and 0.9 percent of MVA.

3.11 INDUSTRY COST STRUCTURE

DOE developed the industry cost structure from publicly available information from the American Survey of Manufactures ("ASM")[47] (Table 3.11.1 and Table 3.11.2). Table 3.11.1 presents power, distribution, and specialty transformer manufacturing industry employment levels (NAICS Code 335311) and earnings from 2018 and 2019. The number of production workers has remained relatively stable. Total employment and the payroll for all employees have also remained relatively stable at an average of 18,221 and $1,037 million, respectively, over both years.

Table 3.11.1 Employee and Payroll Data For Power, Distribution, and Specialty Transformer Manufacturing Industry

Year	Production Workers	All Employees	Payroll for All Employees *(Million 2016$)*
2019	13,768	18,647	1,061
2018	12,665	17,795	1,013

Table 3.11.2 presents the costs of materials and industry payroll as a percentage of value of shipments from 2018 and 2019. The cost of materials as a percentage of value of shipments has remained around 50% between the years. The cost of payroll for production workers as a percentage of value of shipments has remained relatively constant at 9.69% between the years. The cost of total payroll as a percentage of value of shipments has remained around 17.5% between the years.

Table 3.11.2 Cost of Materials and Payroll as a Percentage of Shipments for Power, Distribution, and Specialty Transformer Manufacturing Industry

Year	Cost of Materials as a Percentage of Value of Shipments *(%)*	Cost of Payroll for Production Workers as a Percentage of Value of Shipments *(%)*	Cost of Total Payroll (Production + Admin.) as a Percentage of Value of Shipments *(%)*
2019	48.48%	9.69%	17.01%
2018	52.54%	9.68%	18.02%

3.12 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 primary kinds of losses in transformers: no-load losses and load losses. No-load losses occur primarily in the transformer core, and for that reason the terms “no-load loss” and “core loss” are sometimes interchanged. Analogously, “winding loss” or “coil loss” is sometimes used in place of “load loss” because load loss arises chiefly in the windings. For consistency and clarity, DOE will use “no-load loss” and “load loss” generally and reserve “core loss” and “coil loss” for when those quantities expressly are meant.

3.12.1 Distribution Transformer Insulation Category

In general, there are two categories of distribution transformer insulation: 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. Insulating liquid insulators other than mineral oil (e.g., ester fluid) have been developed which have a higher flash-point temperature than mineral oil, and transformers with these liquids, in theory, can be used for certain indoor applications. However, data indicates that this practice is not wide spread and less-flammable liquid immersed distribution transformers are used, nearly exclusively, in outdoor applications.

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.

3.12.2 Transformer Efficiency Levels

There are two main types of losses in transformers: no-load losses and load losses. No-load 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. No-load losses are present even if the load on the transformer is zero. Load losses occur in the primary and secondary windings around the core and increase as the square of the load applied to the transformer. Load losses result primarily from the electrical resistance of the winding material.

Figure 3.12.1 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.

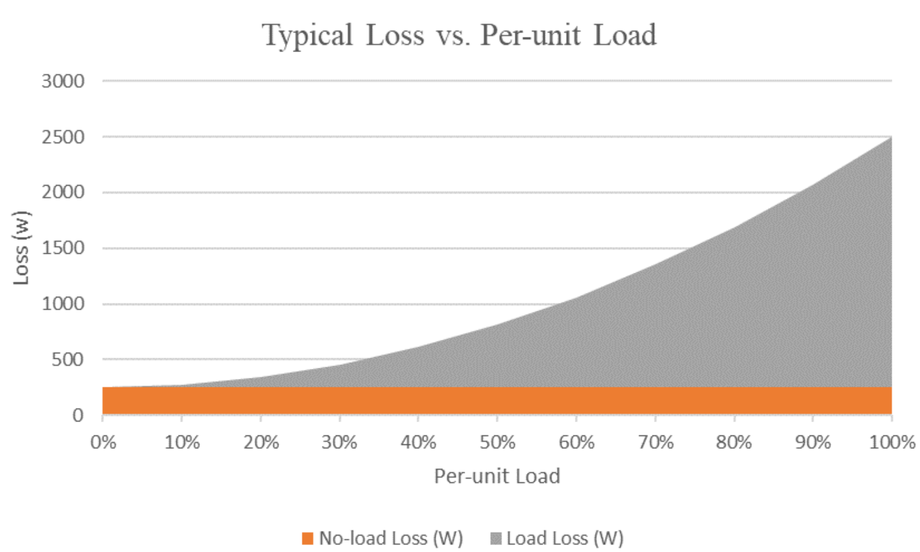


Figure 3.12.1 Transformer Losses Vary with Load (75 Kilovolt-Ampere Dry-type)

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

Eq. 3.2

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

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 Eq. 3.2 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 3.12.1, DOE used Eq. 3.2 to calculate the efficiency of this 75 kVA dry-type transformer at each loading point from 0 to 100 percent of per unit load (PUL). The results are shown in Figure 3.12.2 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 no-load losses are equal to load losses.

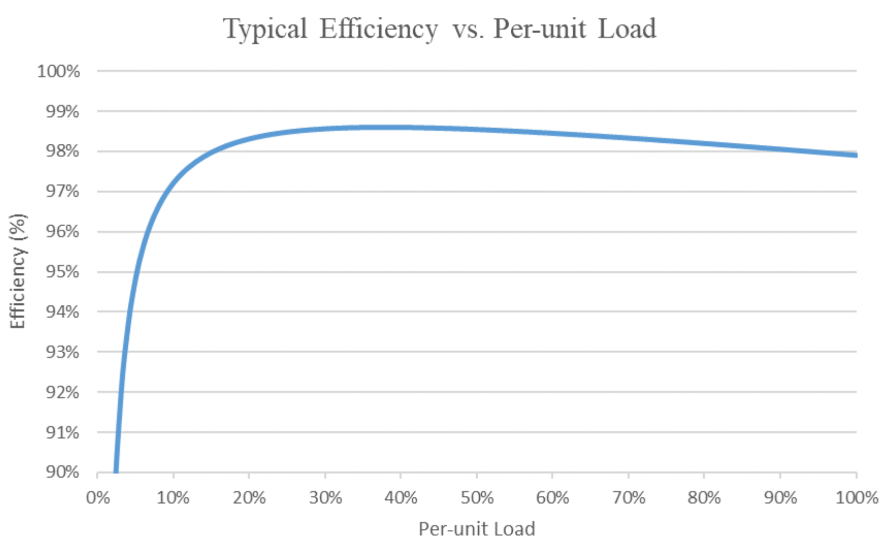


Figure 3.12.2 Transformer Efficiency Varies with Per-Unit Load

Consequently, any discussion of transformer efficiency must include an assumed PUL. The DOE test procedure stipulates that a low-voltage dry-type distribution transformer must be certified at 35 percent PUL and medium-voltage dry-type and liquid-immersed distribution transformers must be certified at 50 percent PUL.

3.12.3 Transformer Losses

This section discusses methods to reduce distribution 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 technical support document. This section summarizes some of the main technological methods for reducing distribution transformer losses.[48] No-load losses occur in the core material of the distribution transformer and are present whenever the transformer is energized. No-load 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 Hz 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. The primary method for reducing no-load losses involved modifying the electrical steel used in the core, as discussed in section 3.12.7.

Load 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, load losses increase and are the dominant source of losses at high loading.

Typically, methods for reducing load losses tend to cause an increase in no-load losses, and vice versa. One method for decreasing load losses 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 no-load losses.

Table 3.12.1 was prepared by ORNL. This table summarizes the methods of making a transformer more efficient by reducing no-load and load losses. 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 3.12.1 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: Increasing core cross-sectional area (CSA) Decreasing volts per turn	 Lower Lower	 Higher Higher	 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: Decreasing core CSA Increasing volts per turn	 Higher Higher	 Lower Lower	 Lower Lower

* Amorphous-core materials may result in greater load loss if flux density drops, requiring a larger core volume.

DOE's analysis of the relationship between cost and efficiency for distribution transformers is presented in Chapter 5.

3.12.4 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.

The theory behind core deactivation technology is that no-load losses dominate when distribution transformers are lightly loaded. Further, a 25 kVA distribution transformer, for example, has fewer no-load losses than a 75 kVA distribution transformer due to the 25 kVA distribution transformer having a smaller core size. In an application where a customer would typically require a 75 kVA distribution transformer, they instead use three 25 kVA distribution transformers, such that the total capacity is equivalent. During periods of low loading, two of the 25 kVA distribution transformers are switched off (*i.e.*, not energized and therefore have zero total losses). The total losses experienced by this 25 kVA distribution transformer is less than the total losses if a 75 kVA distribution transformer were used instead.

Then, as loading increases, load losses become proportionally larger and eventually outweigh the power saved by using the smaller core. At that point, a 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 constantly monitors unit power output so that it can deploy 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.

The real gain in efficiency for this technology is at low PULs, where some transformers in the system could be deactivated. At loadings where all transformers are activated, which may be the case during periods of peak loading or if significant load growth occurs on a given system of transformers, 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.

DOE's review of the market indicates that this technology is not widespread in industry and it is subject to uncertainty from both industry and governmental institutions. 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, each individual transformer in a core deactivation system must separately comply with the energy efficiency standards.

3.12.5 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 3.12.3 shows the configuration of the symmetric core design.[49]

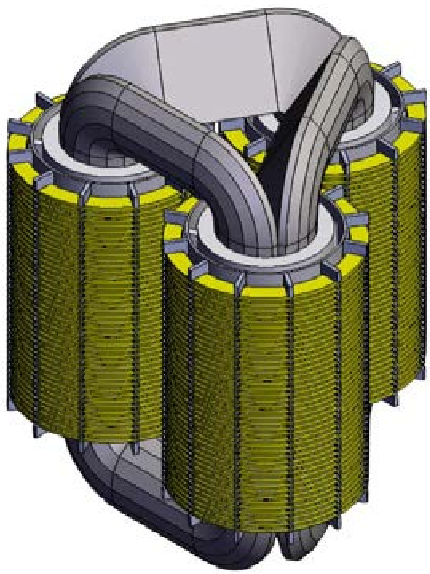


Figure 3.12.3 Graphic of Symmetric-core Configuration

The symmetric core construction offers several theoretical 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.

DOE did not receive any information regarding symmetric core. DOE learned through conversations with manufacturers that the technology exists and has some potential to improve energy efficiency. However, manufacturers stated that there were insufficient benefits to overcome the manufacturing and maintenance challenges of the technology. As such, it may be suitable for certain unique applications, for example certain space constrained applications[49], however manufacturer did not indicate it was suitable for general purpose applications. Because the data on these types of cores is limited, DOE did not consider symmetric core designs in this rulemaking.

3.12.6 Less-Flammable Liquid-Immersed Distribution Transformers

As mentioned in section 3.3, liquid-immersed distribution transformers provide benefits in the form of enhanced electrical insulation and enhanced cooling. Traditionally, liquid-immersed distribution transformers have used mineral oil to provide electrical insulation. However, another type of insulating fluid that is less flammable than mineral oil, typically natural or synthetic ester fluid, have become more common in recent years. DOE studied the differences between mineral oil cooled units and less-flammable cooled units. IEEE standard

C57.12.80-2010 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 affect 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. 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.

DOE is aware of an industry effort to take advantage of the increased thermal protections associated with LFLI distribution transformers as a mean of increasing the capacity of the distribution transformers without increasing the size.[50] This concept proposes to include two full-load kVA ratings for a LFLI distribution transformer – a lower kVA based on the traditional safe temperature rise using mineral oil and a higher kVA based on the additional temperature rise that can be achieved with LFLI insulating fluids. Such an approach, if widely adopted, could increase the load on a given distribution transformer core and coil size. However, DOE does not have any data indicating that this practice is currently being used in industry. Therefore, DOE did not consider it in this preliminary analysis.

3.12.7 Electrical Steel Technology

Distribution transformer cores are constructed from a specialty kind of steel, know as electrical steel. Electrical steel is an iron alloy specifically engineered to minimize hysteresis losses and have high magnetic permeability. These alloys typically include a small percentage of silicon, and as such are often referred to as silicon steels. In producing distribution transformer cores, the electrical steel is produced in thin strips, which are then cut and stacked or wound together to into a core shape, often with a thin insulating coating on the surface of the electrical steel. This process of stacking or winding thin laminations is done to reduce the eddy currents produced within the electrical steel.

3.12.7.1 Conventional Electrical Steel

Broadly speaking, electrical steel can be categorized into conventional electrical steel and amorphous electrical steel. Historically, conventional electrical steel has been the dominant product in distribution transformer cores. When producing conventional electrical steel, manufacturers can choose to institute special processing for controlling the crystal formation orientation. Electrical steels that are produced without special consideration to their crystal grain formation orientation are know as non-oriented electrical steel (NOES). Electrical steels that do control for grain orientation are known as grain-oriented electrical steel (GOES) or cold-rolled grain-oriented electrical steel (CRGO).

NOES does not control for grain orientation and as such produces an equal magnetic current in all directions. While this is a useful feature when the direction of magnetic flux changes constantly, such as for electric motors, it leads to inefficient designs when the magnetic flux is in constant directions, as is the case with distribution transformers. The lack of additional control of grain orientation means that NOES tends to be less expensive than CRGO steel. Historically, it was used in distribution transformers somewhat, due to the lesser costs. However, as the U.S. and other countries began to value the efficiency of distribution transformers, it has largely been phased out of use. DOE did consider design options with NOES, however, all such design options were below the current efficiency standards and as such, were not included in DOE's analysis.

GOES is the dominant material used in distribution transformer cores. The tight control over its crystal orientation makes it such that the magnetic flux density is increased in the direction of the grain-orientation. Over time, manufacturers have developed different methods for reducing the losses produced at a given flux density in electrical steel. In recent years, there has been a proliferation of more advanced GOES. High-permeability GOES, for example, is able to operate at higher magnetic induction than conventional GOES and typically has lower core losses at identical induction levels. Manufacturers have also identified methods for introducing local stain on the surface of electrical steels, through a process known as domain-refinement, such that the core losses are reduced. The domain-refinement process is typically performed with a high-temperature laser, however, the core loss benefits provided by this laser treatment do not survive the high-temperature annealing process used to relieve stressed in wound core distribution transformer designs. As such, it is primarily used in stacked core designs. Newer domain-refinement technologies utilize mechanical scribing or chemical etching to create a heat-proof, permanent domain-refinement. The core less benefit of these permanently domain-refined steels do survive high-temperature annealing and as such can be used in wound core applications.

Traditionally, GOES has been noted with "M" grade designators to distinguish between products, as was done during the April 2013 Final Rule. While some distribution transformer manufacturers often still use M designators when referencing differing grades of electrical steels, DOE did not observe a consensus in industry as to what the M grade designates. "M3," for example, was used in conversation with manufacturers to reference any steel with similar loss performance as the M3 steel from the April 2013 Final Rule, or any steel that was 0.23 mm thick, even if the core losses were better.

As more advanced GOES has been produced, the traditional M grades do not sufficiently distinguish all the variety of GOES technology options. GOES is produced in thicknesses ranging from 0.18-0.35 mm and can span a range of core losses depending on the specific chemistries and manufacturing techniques used. Steel manufacturers have largely adopted a naming system that includes the steel thickness, a brand specific designator, followed by the guaranteed core losses of that steel in W/kg at 1.7 Tesla ("T") and 50 Hz. For example, if Steel Company X offers a high-permeability grain-oriented steel that is 0.23 mm thick with a guaranteed core loss of 90 W/kg at 1.7 T and 50 Hz, it would be represented as "23SCX090." The "23" represents 0.23 mm thickness, the "SCX" is a specific brand designator from Steel Company X, and "090" represents the core losses. In the U.S., power is delivered at 60 Hz and the flux density can vary based on distribution transformer design, so the core losses reported in the steel name is not identical to the performance in the distribution transformer, however, it generally is a good indicator of the relative performance of different steels.

DOE is aware of some industry standard naming conventions that distinguish between conventional grain-oriented steels, high-permeability grain-oriented, and domain-refined high-permeability grain-oriented steels. However, DOE is not aware of an industry naming convention that further separates the heat-proof domain-refined steels from the non-heat-proof laser domain-refined steels. Therefore, DOE has identified the steels used in its analysis using the traditional M-grades for conventional grain-oriented electrical steels and a steel thickness, type, and losses designator for high-permeability steels. The GOES type designators used in this analysis are given in Table 3.12.2.

Table 3.12.2 Conventional Steel Type Designators for Distribution Transformers

DOE Steel Type Designator in Design Options	Technology
M-Grades	Conventional (not high-permeability) Electrical Steel
hib	High-Permeability Grain-Oriented Electrical Steel
dr	Non-Heat Proof, Laser Domain-Refined, High-Permeability Grain-Oriented Electrical Steel
pdr	Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Electrical Steel

While GOES can be produced in a variety of thicknesses, ranging from 0.18-0.35 mm, industry has largely settled on the 0.23 mm thickness steel as the predominant steel thickness. Thinner steels are generally considered harder to work and thicker steels have higher losses. Using a standard thickness steel, while not required by manufacturers, is sometimes preferred as it minimizes the changes manufacturers need to make to their distribution transformer designs or manufacturing processes. DOE used input from industry and the brochures of several of the major grain-oriented electrical steel producers to identify materials for inclusion in its analysis.

In general, there is a diverse offering of similarly performing electrical steels in the global market. DOE has listed the electrical steels considered in this analysis, in Table 3.12.3.

Table 3.12.3 Conventional Steel Options Considered in this Analysis

DOE Designator in Design Options	Technology
Conventional Grain-Oriented Electrical Steel	
M6	0.35 mm thickness, Conventional Grain-Oriented Steel
M5	0.30 mm thickness, Conventional Grain-Oriented Steel
M4	0.27 mm thickness, Conventional Grain-Oriented Steel
M3	0.23 mm thickness, Conventional Grain-Oriented Steel
M2	0.18 mm thickness, Conventional Grain-Oriented Steel
High-Permeability Grain-Oriented Electrical Steel	
23hib090	0.23 mm thickness, High-Permeability Grain-Oriented Steels
23pdr085	0.23 mm thickness, Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Steels
23dr080	0.23 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
23pdr075	0.23 mm thickness, Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Steels
23dr075	0.23 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
20dr070	0.20 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels

In general, the electrical steel market has been subject to a variety of capacity and supply concern, for certain grades of electrical steel, and price variation in response to domestic and foreign trade policies. In cases where fewer steel suppliers offer a grade of electrical steel, this is reflected in higher prices, however, this analysis does not explicitly limit the quantity of a given steel that can be selected. The electrical steel costs used in this analysis are discussed in Chapter 5 of this TSD. A more detailed description of the electrical steel market is presented in Appendix Chapter 3A of this TSD.

3.12.7.2 Amorphous Steel

Amorphous steel is a type of electrical steel that is produced by rapidly cooling (on the order of 1 million ºC per second) molten alloy such that crystals do not form. The resulting product is significantly thinner than conventional electrical steel (about one tenth as thick) and has substantially lower core losses for an equivalent weight of steel. Relative to conventional steel, amorphous steel reaches magnetic saturation at a lower flux density and has a lower lamination factor[c]. This means that amorphous cores tend to be larger in size than cores products of conventional steel.

[c] Lamination factor or stacking factor is a measurement of how closely laminations of steel can be stacked or wound together. The measurement is given as a percentage that indicates what percentage of a given core volume is occupied by electrical steel. A higher lamination factor indicates the ability to more tightly pack steel into a core.

Amorphous steel technology has existed for many decades and has been used in distribution transformers dating back to the late 1980s.[51] In many countries, namely low labor cost countries with significant electrification, like India and China, and in certain regions that place a high value on a reduction in distribution transformer losses (certain provinces of Canada, for example), amorphous steel is widely used in the cores of distribution transformers.[52]

In the past, manufacturers have had concern regarding the brittleness, stacking factor, flux density, and number of suppliers of amorphous steel. Based on conversations with manufacturers, many of these concerns have been alleviated as distribution transformer manufacturers have gained more experience with amorphous distribution transformers. In general, nearly all liquid-immersed distribution transformer manufacturers that sell to the US market have some experience and capacity to product amorphous steel core distribution transformers.

However, there are still barriers for manufacturers to transitioning to widely using amorphous steel in the US market. During the April 2013 Final Rule, DOE noted that there was only one domestic supplier of amorphous steel and the limited supply from companies based in China that was of questionable quality. 78 FR 23336, 23381-23386. In recent years, manufacturers noted a rapid growth in the availability and quality of amorphous materials from China. DOE does not consider the supply of amorphous ribbon to be a significant barrier to its adoption. DOE also notes that domestically, there is one supplier of amorphous steel and one supplier of GOES steel.

Another barrier to the adoption of amorphous steel distribution transformers is that production of amorphous steel cores requires a different production technology as compared to conventional steels. A company that has made significant capital investment in conventional steel core production technologies, such as mitering equipment, would reduce the capital utilization of their equipment if they invested heavily in producing amorphous core. For this reason, amorphous distribution transformer cores and generally purchased as finished cores and not directly manufactured by distribution transformer manufacturers.

In this analysis, DOE has identified two types of amorphous steel as possible technology options for inclusion in distribution transformers. The first technology option DOE has designated as “am” and is identical to the “SA1” material that was included in the April 2013 Standards Final Rule. This material is now offered by multiple suppliers from several countries. DOE also is aware of a second type of amorphous steel designated in this preliminary analysis as “hibam” or “high-permeability amorphous steel.” DOE is only aware of one manufacturer of this high-permeability amorphous steel.[d]

This hibam material is slightly thicker than the am material, has a higher stacking factor, and a higher magnetic saturation. At a given flux density, the hibam material has similar core losses to the am material, however, it is able to operate at a higher flux density. This gives

[d] DOE is aware of marketing for another derivative of the hibam material that uses mechanical scribing to further reduce core losses but does not have sufficient data on this derivative or any details on whether it is commercially available at this time.

manufacturers increased flexibility when designing distribution transformer and can allow them to reduce the size of the amorphous cores.

From a technology perspective, manufacturers generally considered the hibam material an improvement in virtually every way over the traditional am material. The primary barrier to its usage is that it is only offered from a single supplier and is higher priced than foreign sourced traditional am material. Due to fears of having distribution transformer designs rely on a single supplier, manufacturers do not always reoptimize their designs to take full advantage of the hibam material and often incorporate it into their existing amorphous distribution transformer designs. DOE has denoted the potential amorphous steel options using the designators in Table 3.12.4.

Table 3.12.4 Amorphous Steel Technology Options

DOE Designator in Design Options	Technology
am	Traditional Amorphous Steel
hibam	High-Permeability Amorphous Steel

REFERENCES

1 IEEE SA. (2015). *IEEE C57.12.90-2015 – IEEE Standard Test Code for Liquid-Immersed Distribuiton, Power, and Regulating Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_90-2015.html

2 IEEE SA. (2020). *IEEE C57.12.91-2020 – IEEE Standard Test Code for Dry-Type Distribution and Power Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_91-2020.html

3 IEEE SA. (2015). *IEEE C57.12.00-2015 – IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_00-2015.html

4 IEEE SA. (2020). *IEEE C57.12.01-2020 – IEEE Standard General Requirements for Dry-Type Distribution and Power Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_01-2020.html

5 IEEE SA. (2013). *IEEE C57.12.35-2013 – IEEE Standard Bar Coding for Distribution Transformers and Step-Voltage Regulators*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_35-2013.html

6 IEEE SA. (2015). *IEEE C57.12.37-2015 – IEEE Standard for the Electronic Reporting of Distribution Transformer Test Data*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_37-2015.html

7 IEEE SA. (2017). *IEEE C57.12.58-2017 – IEEE Guide for Conducting a Transient Voltage Analysis of a Dry-Type Transformer Coil*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_58-2017.html

8 IEEE SA. (2020). *IEEE C57.12.60-2020 – IEEE Standard for Thermal Evaluation of Insulation Systems for Dry-Type Power and Distribution Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_60-2020.html

9 IEEE SA. (2020). *IEEE C57.12.70-2020 – IEEE Standard for Standard Terminal Markings and Connections for Distribution and Power Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_12_70-2020.html

10 IEEE SA. (2011). *IEEE C57.135-2011 – IEEE Guide for the Application, Specification, and Testing of Phase-Shifting Transformers*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_135-2011.html

11 IEEE SA. (2012). *IEEE C57.154-2012 – IEEE Standard for the Design, Testing, and Application of Liquid-Immersed Distribution, Power, and Regulating Transformers Using High-Temperature Insulation Systems and Operating at Elevated Temperatures*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_154-2012.html

12 International Electrotechnical Commission. (Accessed on 08/02/2021). Available online at: *https://webstore.iec.ch/home*

13 NEMA, *About the National Electrical Manufacturer Association*, (Accessed on 08/02/2021). Available online at: https://www.nema.org/about

14 IEEE, *About IEEE*, (Accessed on 08/02/2021). Available online at: https://www.ieee.org/about/

15 IEC, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.iec.ch/about-us

16 ANSI, *About ANSI*, (Accessed on 08/02/2021). Available online at: https://www.ansi.org/about/introduction

17 Choi, Dong Geun; Puskar, Erik (2014). "A Review of U.S.A. Participation in ISO and IEC". National Institute of Standards and Technology: 29. doi:10.6028/NIST.IR.8007

18 Hitachi ABB Power Grids, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.hitachiabb-powergrids.com/us/en/about-us/who-we-are

19 ERMCO, *About ERMCO*, (Accessed on 08/02/2021). Available online at: https://www.ermco-eci.com/about-ermco

20 Eaton Corporation, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.eaton.com/us/en-us/company/about-us.html

21 Howard Power Solutions, *About Us*, (Accessed on 08/02/2021). Available online at: http://howard-ind.com/Power/Home/AboutUs

22 Power Partners, (Accessed on 08/02/2021). Available online at: https://powerpartners-usa.com/about/

23 Prolec-GE, *Who we are*, (Accessed on 08/02/2021). Available online at: https://prolec.energy/quienes-somos-prolec-ge/?lang=en

24 Federal Pacific, *About Electro-Mechanical Corporation*, (Accessed on 08/02/2021). Available online at: https://www.federalpacific.com/about-us/

25 Hammond Power Solutions, *Our Company*, (Accessed on 08/02/2021). Available online at: https://www.hammondpowersolutions.com/our-company

26 Hubbell Incorporated, *About Hubbell*, (Accessed on 08/02/2021). Available online at: https://www.hubbell.com/hubbell/en/about-hubbell

27 Olsun Electrics Corporation, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.olsun.com/about-us/

28 Schneider Electric SE, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.se.com/us/en/about-us/

29 JST Power Equipment, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.jstpower.com/about/#history

30 MGM Transformer Company, *About Us*, (Accessed on 08/02/2021). Available online at: https://www.mgmtransformer.com/about-us/

31 SGB-USA, *About AGB-USA*, (Accessed on 08/02/2021). Available online at: https://www.sgbusa.com/about-sgb-usa/

32 NAICS Association, *335311 – Power, Distribution, and Specialty Transformer* Manufacturing (Accessed on 08/02/2021). Available online at: https://www.naics.com/naics-code-description/?code=335311

33 U.S. Small Business Administration, *Table of Size Standards*, (Accessed on 08/02/2021). Available online at: https://www.sba.gov/document/support--table-size-standards

34 ORNL, 1996. *Determination Analysis of Energy Conservation Standards for Distribution Transformers*, P.R. Barnes, J.W. Van Dyke, B.W. McConnell, S. Das, Oak Ridge National Laboratory, Oak Ridge, Tennessee. ORNL-6847. See docket: http://www.regulations.gov/#!docketDetail;D=EERE-2006-STD-0099

35 IEEE SA. (2017). *IEEE C57.12.120-2017 – IEEE Guide for Loss Evaluation of Distribution and Power Transformers and Reactors*. (Accessed on 08/02/2021). Available online at: https://standards.ieee.org/standard/C57_120-2017.html

36 NRCan, *Amendment 17*, (Accessed on 08/02/2021), Available online at: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-regulations/planning-and-reporting/amendment-17/23606

37 Ontario, *O. Reg. 509/18: Energy and Water Efficiency – Appliances and Products*, , (Accessed on 08/02/2021), Available online at: https://www.ontario.ca/laws/regulation/180509

38 New Brunswick, *Energy Efficiency Act (R.S.N.B. 2011, c.149)* (Accessed on 08/02/2021), Available online at: http://laws.gnb.ca/en/showfulldoc/cr/95-70//20210809

39 Nova Scotia, *Energy-efficient Appliances Regulations, N.S. Reg. 172/2012*, last amended on September 10, 2012 (Accessed on 08/02/2021), Available online at: https://novascotia.ca/just/regulations/regs/eeappliances.htm

40 Gomez, 2001. Jose Antonio Gomez, P.E., Asociacion de Normalizacion y Certificacion (ANCE, Association of Standards and Certification). Mexico City, Mexico. personal communication, June 17, 2001.; Lara, 2001. Ing. Rene Perez Lara, Dirección General de Gas LP y de Instalaciones Eléctricas, Secretaría de Energía. Mexico City, Mexico. Personal communication, May, 2001. (Gas and Electric Installations Division, Department of Energy).

41 Manifestación de Impacto Regulatorio, Proyecto de Norma Oficial Mexicana NOM-002-SEDE-1997. Secretaría de Energía, Mexico City, Mexico, 1997 (Regulatory Impact Analysis,

Proposed Official Mexican Standard NOM-002-SEDE-1997), Department of Energy, Mexico City, Mexico.

42 NORMA Oficial Mexicana NOM-002-SEDE / ENER-2014, Requisitos de seguridad y eficiencia energética para transformadores de distribución, (Accessed on 8/6/2018), Available online at: http://dof.gob.mx/nota_detalle.php?codigo=5358207&fecha=29/08/2014

43 Official Journal of the European Union, *Commission Regulation (EU) No. 548/2014*, May 21, 2014, Available online at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2014.152.01.0001.01.ENG

44 Official Journal of the European Union, *Commission Regulation (EU) No. 2019/1783*, October 1, 2019, Available online at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2019.272.01.0107.01.ENG&toc=OJ%3AL%3A2019%3A272%3ATOC

45 United States International Trade Commission, *Harmonized Tariff Schedule of the United States (2021)*, August 2021, Available online at: https://hts.usitc.gov/current

46 Congressional Research Service, *Section 232 Investigations: Overview and Issues for Congress*, May 18, 2021, Available online at: https://fas.org/sgp/crs/misc/R45249.pdf

47 United States Census Bureau website (Accessed on 08/02/2021), *Annual Survey of Manufacturers: Summary Statistics for Industry Groups and Industries in the U.S.: 2019 and 2018*, Available online at: https://data.census.gov/cedsci/

48 *Energy Efficient Transformers*, Barry W. Kennedy, McGraw-Hill Publishing, New York, NY. *Control of Transformer Losses in Canada*, D.A. Wiegand, IEEE Journal, 1994. *Determination Analysis of Energy Conservation Standards for Distribution Transformers*, P.R. Barnes, J.W. Van Dyke, B.W. McConnell, S. Das, Oak Ridge National Laboratory, Oak Ride, Tennessee. ORNL-6847. See docket: http://www.regulations.gov/#!docketDetail;D=EERE-2006-STD-0099

49 SBG-USA, *About Compact Core*, (Accessed on 08/02/2021), Available online at: https://www.sgbusa.com/compact-core/

50 IEEE Transformer Committee, *Discussion of New Dual Nameplate kVA for Distribution Transformers*, Fall 2020, Available at: https://grouper.ieee.org/groups/transformers/subcommittees/distr/EnergyEfficiency/F20-DOETaskForce-DualkVA-Traut.pdf

51 DeCristofaro, N., *Amorphous Metals in Electric-Power Distribution Applications*, Material Research Society, MRS Bulletin, Volume 23, Number 5, 1998.

52 BPA's Emerging Technologies Initiative, *Phase 1 report: High Efficiency Distribution Transformer Technology Assessment*, April 2020. Available online at: https://www.bpa.gov/EE/NewsEvents/presentations/Documents/Transformer%20webinar%204-7-20%20Final.pdf

CHAPTER 4. SCREENING ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

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.

(5) Unique-Pathway Proprietary Technologies. If a design option utilizes proprietary technology that represents a unique pathway to achieving a given efficiency level, that technology will not be considered further.

This chapter discusses how DOE applied the five screening criteria to all 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 (typically) 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 originally adapted from Table 2.2 in Oak Ridge National Laboratory (ORNL) report number 6847 published July 1996).[1] For most of these approaches, there are clear tradeoffs between no-load losses, load 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

	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) (b) Decreasing volts per turn	 Lower Lower	 Higher Higher	 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 (b) Increasing volts per turn	 Higher Higher	 Lower Lower	 Lower Lower

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

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 the same manner, copper has a higher electrical conductivity and about 40 percent less resistive loss 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. The choice in using copper or aluminum is often based on specific market conditions related to the underlying commodity price of each material. 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 are grain-oriented and can be 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 than conventional materials, and it has higher excitation requirements. Amorphous metal material can also be more 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 lower space factor than conventional electrical steel core materials. The net effect of the lower flux density and higher space factor is a larger core with greater winding (conductor) losses.

The core steels considered in this screening analysis are all those found in commercial use today, although some of the higher performing grain-oriented electrical steel may be targeted for the large power transformers, above the kVA range of what is considered a distribution transformer. These core steels include conventional grain-oriented electrical steel, high-permeability grain-oriented electrical steel, laser domain-refined high-permeability grain-oriented electrical steel, heat-proof permanently domain-refined grain-oriented electrical steel, and amorphous material (wound-core designs). DOE considered all these core materials to be technologically feasible, as they are commercially available from steel manufacturers at varying flux levels and lamination thicknesses. These commercially available conventional electrical 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, conventional electrical steels 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	Conventional Electrical Steel
	Amorphous Steel in Wound Core

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 wartime 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.

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 ongoing.

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 typically 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. Regarding 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 and impracticability to manufacture, install, and service.

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. At least one patented design process involved joining multiple amorphous strips together.[2] However, the process 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 and impracticability to manufacture, install, and service.

4.4.4 Carbon Composite Materials for Heat Removal

One previously patented technology that may be 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.[3] However, 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.

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.

4.4.6 Solid-State (Power Electronics) Technology

The application of solid-state (power electronics) technology to transformers is still being researched. 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.

Solid-state technology has not achieved the same efficiency levels as standard transformer designs (Gen-1 system efficiency was 88%)[4], 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. Solid-state transformers also have not been able to achieve the same level of electrical isolation, meaning they could be more susceptible to lighting strikes and therefore more difficult to service.

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 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.

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.

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

1 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: http://cta.ornl.gov/cta/Publications/Reports/ORNL-6847.pdf

2 Hitachi Ltd., *Transformer and Stacked Iron Core*, World Intellectual Property Organization (WIPO) 2020/017257.

3 Sines, E., *Electrical Power Cooling Technique*, US Patent No. 6,259,347.

4 Yu, W., *Solid State Transformer for Power Distribution Applications*, 2017, Available online at: https://www.energy.gov/sites/default/files/2017/09/f36/%5B5%5D%20NCSU%20-%20Wensong%20Yu.pdf

CHAPTER 5. ENGINEERING ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 5. ENGINEERING ANALYSIS

5.1 INTRODUCTION

This chapter provides the technical support documentation for the engineering analysis, evaluating both liquid-immersed ("LI"), low-voltage dry-type ("LVDT"), and medium-voltage dry-type ("MVDT") 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 medium-voltage dry-type). Following this convention, the U.S. Department of Energy (DOE) developed ten[a] equipment classes ("ECs"), shown in Table 5.2.1.These equipment classes were originally adapted from the National Electrical Manufacturers Association (NEMA)'s TP 1[b] classification system, although they do not follow the classification system precisely. NEMA's TP 1 classified 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 ECs 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. In total, there are 115 kVA ratings across all ECs, as shown in Table 5.2.1.

---

[a] An eleventh equipment class was reserved for underground mining transformers (see 10 CFR 431.196(c)), but energy conservations standards currently apply only to ten equipment classes.
[b] NEMA's TP 1 standard is rescinded. For details, see TSD chapter 3, section 3.7.1.

Table 5.2.1 Equipment Classes and Number of kVA Ratings

EC	Group	Phase Count	BIL (kV)	kVA Range	Number of kVA Ratings
1	LI	1	any	10–833	13
2	LI	3	any	15–2500	14
3	LVDT	1	any	15–333	9
4	LVDT	3	any	15–1000	11
5	MVDT	1	20-45	15–833	12
6	MVDT	3	20-45	15–2500	14
7	MVDT	1	46-95	15–833	12
8	MVDT	3	46-95	15–2500	14
9	MVDT	1	≥96	75–833	8
10	MVDT	3	≥96	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. Because many distribution transformers share similar designs and construction methods, DOE simplified the analysis by creating 14 engineering representative units (RUs), which allow DOE to directly analyze transformer designs with popular attributes and representing a wide range of attributes. These 14 engineering representative units 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).

From these 14 RUs, DOE can scale its results to characterize all 115 kVA ratings. 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 the equipment class containing the representative unit. An example of how DOE applied this scaling appears in section 5.2.2 of this chapter. A technical discussion of the derivation of kVA scaling appears in appendix 5B.

Table 5.2.2 presents DOE’s 14 representative units for analysis. Descriptions of each and the rationale behind the selection of the representative units follow Table 5.2.2.

Table 5.2.2 Engineering Representative Units (RUs) for Analysis

RU	EC	Group	Phase Count	kVA	BIL (kV)	Primary (kV)	Secondary (V)	Rise (°C)	Shape
1	1	LI	1	50	95	14.4	240/120V	65	Rectangular
2		LI	1	25	125	14.4	120/240V	65	Round
3		LI	1	500	150	14.4	277V	65	Round
4	2	LI	3	150	95	12.47Y/7.2	208Y/120	65	Rectangular
5		LI	3	1500	125	29.4GrdY/14.4	480Y/277	65	Rectangular
6	3	LVDT	1	25	10	.48	120/240V	150	Rectangular
7	4	LVDT	3	75	10	.48	208Y/120	150	Rectangular
8		LVDT	3	300	10	.48	208Y/120	150	Rectangular
9	6	MVDT	3	300	45	4.16	480Y/277	150	Rectangular
10		MVDT	3	1500	45	4.16	480Y/277	150	Rectangular
11	8	MVDT	3	300	95	12.47	480Y/277	150	Rectangular
12		MVDT	3	1500	95	4.16	480Y/277	150	Rectangular
13	10	MVDT	3	300	125	4.16	480Y/277	150	Rectangular
14		MVDT	3	2000	125	4.16	480Y/277	150	Rectangular

* "EC" stands for "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.
** All representative units are designed for operation at 60 Hz.

DOE analyzed liquid-immersed transformers using five engineering representative units, based on tank shape, number of phases, and kVA rating. 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 analyzed dry-type distribution transformers using eight engineering representative units, primarily according to BIL rating. 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 represented by representative units 8, 9, or 11, or 13, depending on input voltage and on whether the BIL rating is 10 kV (low-voltage), 20-45 kV, 46-95 kV, or 96-150 kV.

Representative units 9 through 14 may not have the standard BILs associated with a given primary voltage. DOE selected a slightly higher BIL for the representative units 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 representative units, providing a description and explanation of the transformers covered.

Representative Unit 1. This is a basic, high-volume, rectangular-tank, single-phase, liquid-immersed distribution transformer, low-kVA pad-mounted distribution transformer. Transformers represented by this representative unit typically have BILs ranging from 30 kV to 150 kV (the modeled, representative 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 representative unit has a primary voltage less than 35 kV, and a secondary voltage less than or equal to 600 Volts (V).

The configuration selected for RU1 is a 50 kVA pad-mounted unit, as this is a high shipment volume rating.

Representative Unit 2. This is the basic, high-volume line, round-tank (pole-mounted), low-kVA, single-phase, liquid-immersed distribution transformer. Although some manufacturers tend to employ the same basic core/coil design for RU1 and RU2, 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 RU2 typically have BILs ranging from 30 kV to 150 kV (this modeled representative 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 configuration selected for RU2 is a 25 kVA pole-mounted unit, as this is a high-volume rating for pole-mounted transformers.

Representative Unit 3. This unit represents single-phase, liquid-immersed distribution transformers of larger kVA. Together, RUs 1 through 3 cover all the single-phase, liquid-immersed units. Transformers represented by this RU typically have BILs ranging from 30 kV to 150 kV (this modeled representative 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 configuration selected for RU3 is a 500 kVA, round-tank design. 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. Together, results from RU1-3 are used to establish standards for equipment class 1, single-phase liquid-immersed units.

Representative Unit 4. Representative unit 4 represents rectangular tank, three-phase, liquid-immersed distribution transformers of smaller kVA. Transformers represented by this RU typically have BILs ranging from 30 kV to 150 kV (this modeled representative 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 configuration selected for RU4 is a 150 kVA transformer, which is high volume rating.

Representative Unit 5. Representative unit 5 represents rectangular tank, three-phase, liquid-immersed distribution transformers of larger kVA. Together, RUs 4 and 5 are scaled to cover all three-phase, liquid-immersed units. Transformers represented by this RU typically have BILs ranging from 95 kV to 150 kV (this modeled representative 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 configuration selected for this RU is a 1500 kVA transformer, as this is a common rating in this size range. Together, RU4 and RU5 are used to create standards for the whole kVA range in equipment class 2.

Representative Unit 6. Representative unit 6 represents single-phase, low-voltage, ventilated dry-type distribution transformers. Transformers represented by this RU 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 configuration selected for RU6 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 single-phase, LVDT transformers (15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, 167 kVA, 250 kVA, and 333 kVA). Representative unit 6 is used to generate results for equipment class 3.

Representative Unit 7. Representative unit 7 represents three-phase, low-voltage, ventilated dry-type distribution transformers of smaller kVA rating. Transformers represented by this RU 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 configuration selected for RU7 is a 75 kVA transformer, as this is a common rating in this size range.

Representative Unit 8. Representative unit 8 represents three-phase, low-voltage, ventilated dry-type distribution transformers of larger kVA rating. Transformers represented by this RU 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 configuration selected for RU8 is a 300 kVA transformer, as this is a common rating in this size range. RU8 and RU7 are used together to produce results for the entire kVA range of equipment class 4.

Representative Unit 9. Representative unit 9 represents three-phase, medium-voltage, ventilated dry-type distribution transformers of small BIL and small kVA rating. Transformers in RU9 typically have primary voltages less than or equal to 5 kV with a BIL rating between 20 kV and 45 kV. The representative unit for this range has a 45 kV BIL rating; greater BIL ratings typically produce greater losses and DOE wished to ensure that the analytical results would hold for the most challenged end of the BIL range. 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 configuration selected for RU9 is 300 kVA, as this is a common rating in this size range.

Representative Unit 10. Representative unit 10 represents three-phase, medium-voltage, ventilated dry-type distribution transformers of small BIL and large kVA rating. Transformers represented by this RU typically have primary voltages less than or equal to 5 kV with a BIL rating between 20 kV and 45 kV. The representative unit for this range has a 45 kV BIL rating; greater BIL ratings typically produce greater losses and DOE wished to ensure that the analytical results would hold for the most challenged end of the BIL range. 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 configuration selected for this RU is a 1500 kVA transformer, as this is a common rating. Results from RU9 and RU10 are used together to scale to all kVA ratings in equipment class 6. Results from these two RUs are scaled to all kVA ratings in equipment class 5.

Representative Unit 11. Representative unit 11 represents three-phase, medium-voltage, ventilated dry-type distribution transformers of medium BIL and small kVA rating. This RU parallels RU9, with a higher primary insulation level, 46 kV to 95 kV BIL. The representative unit for this range has a 95 kV BIL rating; greater BIL ratings typically produce greater losses and DOE wished to ensure that the analytical results would hold for the most challenged end of the BIL range. 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 shipments for this RU 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.

Representative Unit 12. Representative unit 12 represents three-phase, medium-voltage, ventilated dry-type distribution transformers of medium BIL and large kVA rating. This RU parallels RU10, with a higher primary insulation level, 46 kV to 95 kV BIL. The representative unit for this range has a 95 kV BIL rating; greater BIL ratings typically produce greater losses and DOE wished to ensure that the analytical results would hold for the most challenged end of the BIL range. 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 configuration selected for this RU is a 1500 kVA transformer, as it is a common rating in this size range and BIL rating because they require additional insulating material and mechanical clearances that inhibit power transfer. RU11 and RU12 are used to produce results for the entire kVA range of equipment class 8 and are scaled to equipment class 7.

Representative Unit 13. Representative unit 13 represents three-phase, medium-voltage, ventilated dry-type distribution transformers of large BIL and small kVA rating. This design parallels RUs 9 and 11 as the smaller-kVA specification in its respective BIL range of 96 kV to 150 kV. RU13 has a 125 kV BIL rating; higher BIL ratings usually produce greater losses. Although 125 kV is not the highest rating in BIL range represented by these RUs, it is used because of being a more common rating than 150 kV. The 225 kVA rating is considered 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.

The configuration selected for RU13 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 RU. RU13 and RU14 are used to develop results for the full kVA range of equipment class 10 and scaled to set standards for equipment class 9.

Representative Unit 14. Representative unit 13 represents three-phase, medium-voltage, ventilated dry-type distribution transformers of large BIL and large kVA rating. This design parallels RUs 10 and 12 as the smaller-kVA specification in its respective BIL range of 96 kV to 150 kV. RU14 has a 125 kV BIL rating; higher BIL ratings usually produce greater losses. Although 125 kV is not the highest rating in BIL range represented by these RUs, it is used because of being a more common rating than 150 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.

The configuration selected for RU14 is a 2000 kVA transformer, which occurs toward the high end of the range covered by this RU. RU13 and RU14 are used to develop results for the full kVA range of equipment class 10 and scaled to set standards for equipment class 9.

5.2.1 Summary of Representative Unit Coverage

Figure 5.2.1 displays the specific kVA ratings (y-axis) for each RU (x-axis). To capture any design differences between a single-phase pole and a pad-mounted transformer, DOE analyzed units in both RU1 (pad-mounted) and RU2 (pole-mounted) with relative close kVA ratings (50 and 25, respectively).

As discussed in TSD chapter 9, Shipments Analysis, 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.

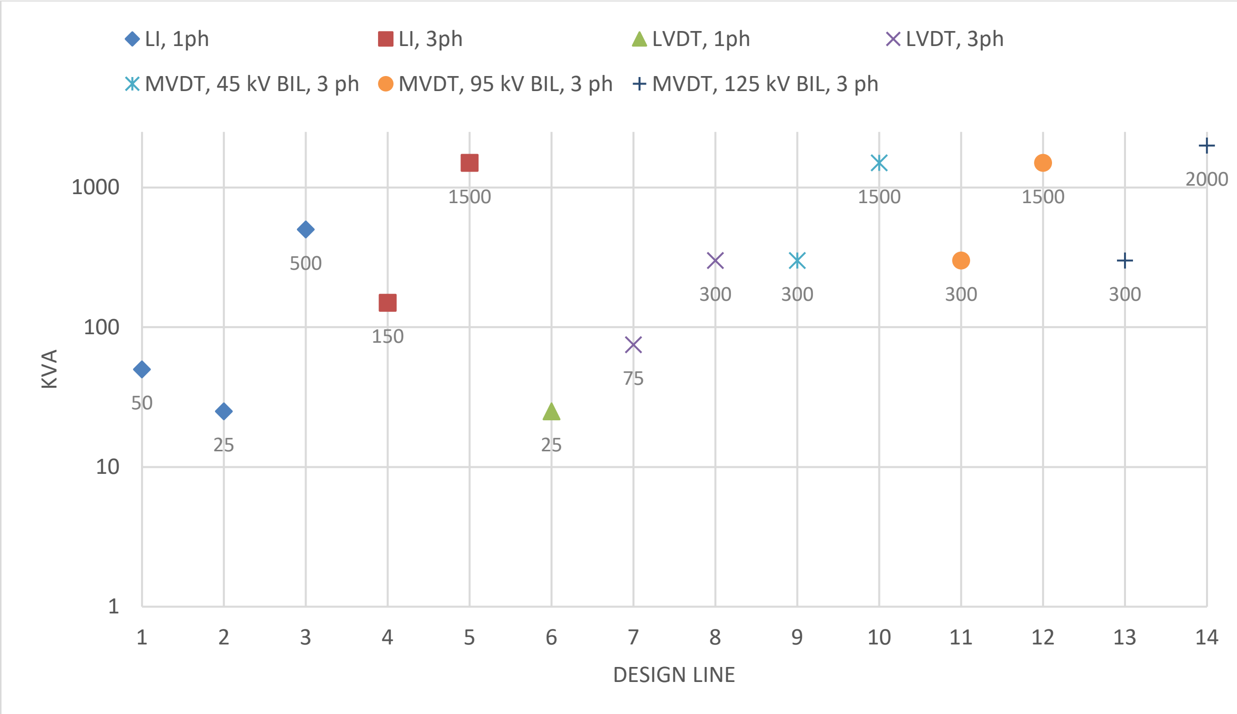


Figure 5.2.1 Representative Units by kVA, Phase, Insulation, and BIL

5.2.2 Scaling Relationship in Transformer Manufacturing

DOE simplified the engineering analysis by creating RUs and scaling the results of the analysis on these representative units to others within their respective equipment classes. 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 5C.

The scaling formulas 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 5.2.3 depicts the most common scaling relationships in transformers.

Table 5.2.3 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 5.2.4 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 suggest that an ideal transformer will exhibit a scaling exponent of 0.75, different exponents may better characterize certain groups of real world transformers. For the engineering analysis, 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 presented by distribution transformer manufacturers during the negotiations during the April 2013 standards rulemaking. 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 5.2.4.

Visualizing the standard for a particular equipment class as a function on a plot of efficiency (y-axis) versus kVA (x-axis), efficiency levels in each RU are a series of points along an imaginary vertical line that intersects the x-axis at the RU's kVA. More than one RU in a given equipment class will produce more than one series of points. Because exponential scaling is performed on loss values and because exponential functions will appear as straight lines on logarithmic-scale plots, the concept is more tractable if illustrated that way, as is done in section 5.2.1. Note that efficiency and loss values have a one-to-one correspondence, where either coordinate can be used 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 RU, as was done by the negotiating committee for MVDT transformers during the April 2013 standards rulemaking, the task remains to scale those chosen efficiencies at certain kVA ratings to all the other kVA ratings that DOE covers. Fitting a straight line[c] through the chosen points accomplishes that goal but may produce a slope different from .75.

Deriving the .75 rule requires several assumptions, among them that the overall form and proportions of the transformer remain fixed as it changes in size. This assumption may break down in several ways. For example, MVDT BIL ratings require fixed spacings between the edge of a winding and the window of a core, regardless of size (kVA). 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.

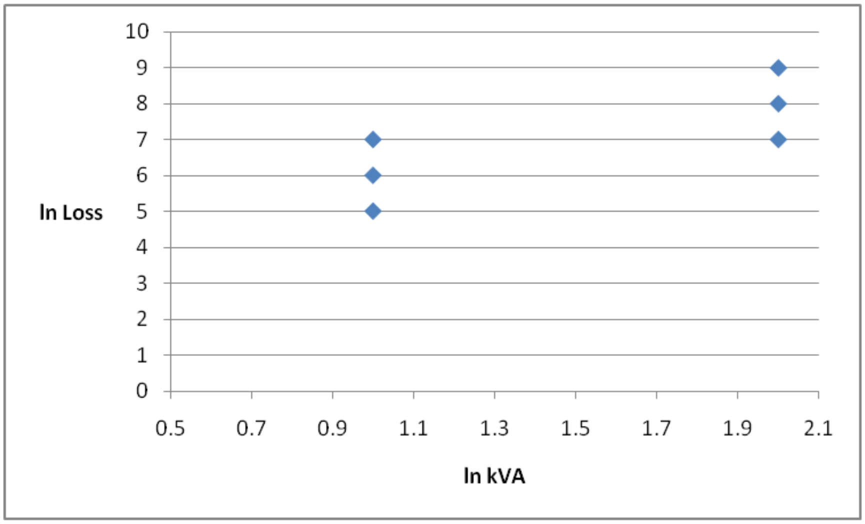


Figure 5.2.2 Efficiency Levels within an Equipment Class (Logarithmic)

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

Table 5.2.4 Scaling Exponents by Equipment Class

Distribution Transformer Equipment Class	Scaling Exponent
1. Liquid-immersed, medium-voltage, 1-phase	.76
2. Liquid-immersed, medium-voltage, 3-phase	.79
3. Dry-type, low-voltage, 1-phase	.75
4. Dry-type, low-voltage, 3-phase	.74
5. Dry-type, medium-voltage, 1-phase, 20-45 kV BIL	.67
6. Dry-type, medium-voltage, 3-phase, 20-45 kV BIL	.67
7. Dry-type, medium-voltage, 1-phase, 46-95 kV BIL	.67
8. Dry-type, medium-voltage, 3-phase, 46-95 kV BIL	.67
9. Dry-type, medium-voltage, 1-phase, $\geq$ 96 kV BIL	.68
10. Dry-type, medium-voltage, 3-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:

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

Eq. 5.1

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

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

Eq. 5.2

where:

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

Eq. 5.1 and Eq. 5.2 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 scales to the "E" power. Specifically:

$$LL_1 = TL_1 - NL_1$$

Eq. 5.3

where:

LL_1 = load losses of transformer "1"

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

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

Eq. 5.4

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

Eq. 5.5

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

Eq. 5.6

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, 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 5C 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 RUs to the 115 kVA ratings that it did not analyze. DOE applied the scaling rule within the RUs in the national impact analysis (chapter 10), where it calculated efficiency ratings for the 115 kVA ratings not analyzed.

5.3 TECHNICAL DESIGN INPUTS TO 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.[d] The OPS software used two primary inputs: (1) a design option combination, which included core steel grade, primary and secondary conductor material, and core configuration, and (2) a loss valuation. DOE examined numerous design option combinations for each representative unit. The OPS software generated 518 designs for each design option combination based on unique loss valuation combinations. Taking the loss value combinations, known in the industry as A and B values and representing the commercial consumer's present value of future no-load and load losses in a distribution transformer, respectively, the OPS software sought to generate the minimum total ownership cost (TOC). TOC can be calculated using the equation below.

$$TOC = Transformer\ Purchase\ Price + A * [No\ Load\ Losses] + B * [Load\ Losses]$$

From the OPS software, DOE received thousands of different distribution transformer designs. DOE used these distribution transformer designs to create a manufacturer selling price ("MSP"). The MSP was generated by applying material costs, labor estimates, and various mark-ups to each design given from OPS. The engineering result included hundreds of unique distribution transformer designs, spanning a range of efficiencies and MSPs. DOE used this data as the cost versus efficiency relationship for each representative unit. DOE then extrapolated this relationship, generated for each representative unit, to all of the other, unanalyzed, kVA ratings within that same equipment class.

DOE notes that in generating designs, the OPS software uses seed material prices that are not necessarily identical to the prices DOE applies post-hoc in generating the manufacturer selling prices. DOE regularly updates the pricing in its analysis in response to market conditions

---

[d] DOE contracted OPS for the previous rulemaking which culminated in the April 2013 standards final rule. DOE used the same data set of OPS-generated distribution transformer designs for this preliminary TSD.

and manufacturer feedback. However, it would be impractical for DOE to re-run the thousands of distribution transformer software designs in response to price fluctuations. For example, a decrease in conductor prices would encourage a TOC optimized software program to increase pounds of conductor in an effort to minimize load losses. Instead, DOE updates the price of the existing distribution transformer design.

As such, the distribution transformers designs included in DOE's analysis are designed to represent technologically feasible designs with a manufacturer selling price representative of the current market average prices. It is not designed to represent the optimal design under DOE's published material prices. DOE relies on a large breadth of A and B values and design option combinations to generate a sufficient number of technologically feasible designs such that an accurate cost-efficiency curve is generated.

The designs generated by OPS have 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 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 per-unit 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 3.7, 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 per-unit load. The A and B values consider a range of factors that vary across customers.

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 5.3.1 and Table 5.3.2) to create a complete set of efficiency levels for each design option combination analyzed. The efficiency levels spanned from a baseline 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 high, pushing the software to design near 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 5.3.1 presents the ranges and incremental steps for the A and B combinations used in the three grids.

Table 5.3.1 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 $\$1*(0.50)^2$, 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 5.3.2 presents the range of the two fan combinations used in the analysis.

Table 5.3.2 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 5.3.1 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.

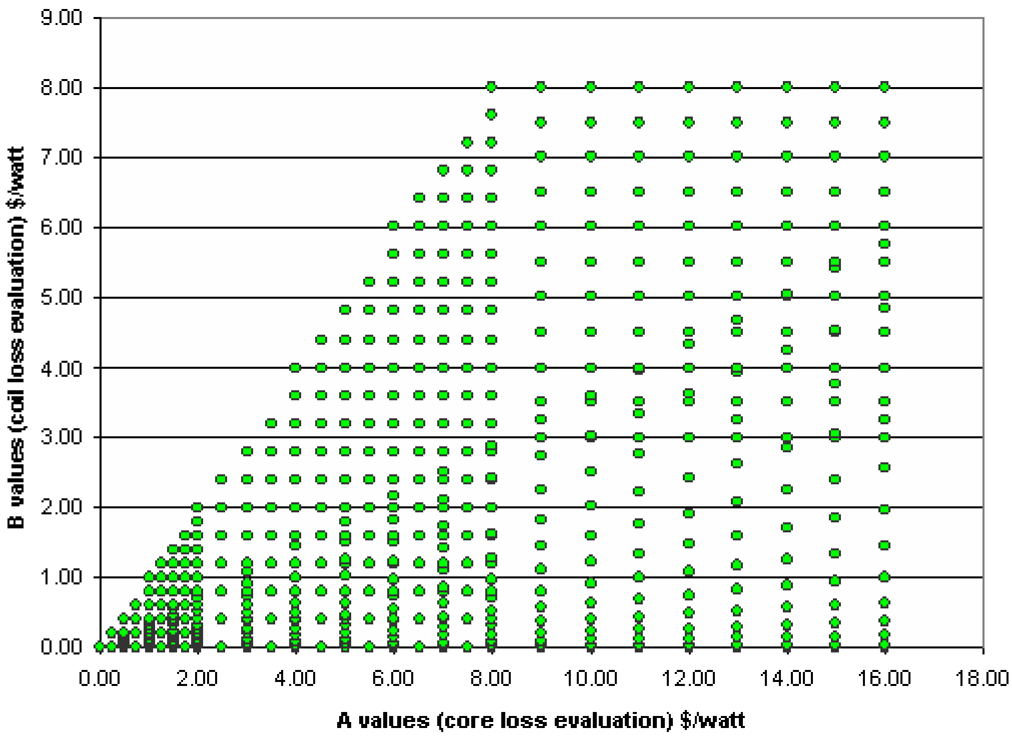


Figure 5.3.1 A and B Combination Software Inputs Used in the Engineering Analysis

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 Steel 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, the winding materials (aluminum or copper), and core configurations. For each of the RUs, 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 10-17 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). Table 5.3.3 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 5.3.3 Core Steel Grades, Thicknesses and Associated Losses

Steel Grade	Nominal Thickness *inches*	Typical Core Loss at 60 Hz Watts per Pound at magnetic flux density*	Notes / Remarks
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
23hib090	0.009	0.37 Watts/lb at 1.5 T 0.52 Watts/lb at 1.7 T	0.23 mm thickness, High-Permeability Grain-Oriented Steels
23pdr085	0.009	0.34 Watts/lb at 1.5 T 0.46 Watts/lb at 1.7 T	0.23 mm thickness, Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Steels
23dr080	0.009	0.34 Watts/lb at 1.5 T 0.47 Watts/lb at 1.7 T	0.23 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
23pdr075	0.009	0.32 Watts/lb at 1.5 T 0.43 Watts/lb at 1.7 T	0.23 mm thickness, Heat-Proof, Permanently Domain-Refined, High-Permeability Grain-Oriented Steels
23dr075	0.009	0.32 Watts/lb at 1.5 T 0.44 Watts/lb at 1.7 T	0.23 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
20dr070	0.008	0.30 Watts/lb at 1.5 T 0.40 Watts/lb at 1.7 T	0.20 mm thickness, Laser Domain-Refined, High-Permeability Grain-Oriented Steels
am	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

For this preliminary analysis, DOE maintained the existing distribution transformer designs from the April 2013 Final Rule as all of these designs can still be physically built. DOE did not redesign there transformers, only updated the material prices to get an updated manufacturer selling price.

For newer core steels not included in the April 2013 Final Rule, DOE adapted models of conventional steel to reflect some of the lower loss steels that have come into the market since the April 2013 Final Rule. This was conducted by assuming the core steel of a previous model was directly swapped for a new lower loss core steel while the core size, operating flux density, and all other relevant attributes remained the same. For example, if a design in the last rulemaking used 23dr080 steel at an operating flux of 1.54 T, DOE generated the results for

23dr075 by multiplying the no-load losses of the 23dr080 design by that ratio of core losses of 23dr075 steel at 1.54 T over the core losses of 23dr080 steel at 1.54 T. The typical values of each of these conventional core steels are presented at 1.5 and 1.7 T, however, DOE used core loss curves (core loss versus flux density across the entire operating range) to calculate the efficiency of a distribution transformer using the different core steel.

DOE received interview feedback from manufacturers that this would generate a valid design, assuming the core density and stacking factor are not changed, although it may not be the true optimal design given that a lower loss steel allows more flexibility in the load losses. Because DOE's designs cover a wide range of A and B values, this method will generate sufficiently accurate estimates to include in the engineering analysis.

5.3.2.1 High-Permeability Amorphous Steel

Since the publication of the April 2013 standards final rule, DOE has learned of an additional variant of amorphous steel to the traditional amorphous steel ("am"; "SA1" in the April 2013 final rule) product. This new variant is a high-permeability amorphous steel ("hibam"). Based on discussions with manufacturers, hibam has similar properties to the traditional am, but with potentially increased density, peak flux density, and packing factor[1] Though amorphous transformers are generally agreed to carry lower core losses, lower peak flux density and greater core size, relative to conventional cores, have limited their uptake in certain applications. If hibam improves upon those perceived limitations of traditional am, it may result in greater adoption of amorphous core steel in the market. DOE has also observed marketing for another derivative of the hibam material that uses mechanical scribing to further reduce core losses but does not have sufficient data to analyze its benefits and does not know any details regarding its whether it is commercial available at this time.[2]

DOE's review of manufacturer literature and discussion with manufacturers did not indicate that a one-for-one swap of hibam would necessarily improve transformer efficiency. Hibam may not exhibit a loss advantage relative to am at a given typical flux density (e.g., 1.3 T) and therefore not improve a design if substituted for am without modification of other aspects of the transformer. In particular, the ability of am to operate at higher flux densities may enable smaller core cross sections that require less conductor to surround and thus enable reduction of conductor loss.

DOE did not include any new designs for the hibam steel in this analysis and instead updated existing traditional am prices to current prices. While there are some design-flexibility advantages to using the high-permeability amorphous steel, it is only available from a single supplier. Several manufacturers expressed in interviews that they would be hesitant to rely on a single supplier of amorphous material for any higher volume unit. Further, the hibam steel can be integrated into manufacturers existing amorphous designs, with minimal changes. The combination of the single source of hibam and possible integration of hibam into existing designs indicates that manufacturers would be unlikely to redesign existing amorphous distribution transformers until the capacity of hibam increases, such that they are not stuck with a single supplier for all of their amorphous distribution transformer designs. DOE may consider including hibam distribution transformer designs in future analytical updates if manufacturers indicate that there is sufficient supply, and number of suppliers, to redesign distribution transformers to take advantage of the higher flux density.

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 5.3.4 provides a list of all the core configurations used for each of the 14 RUs. 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 5.3.4 Core Configurations Used in Each Representative Unit

RU	# Phases	Core Configurations Used in the Engineering Analysis
1	1	Wound core - distributed gap; Shell-type
2	1	Wound core - distributed gap; Shell-type or core-type
3	1	Wound core - distributed gap; Shell-type or core-type
4	3	Wound core - distributed gap; 5-leg
4	3	Wound core - distributed gap; 5-leg
6	1	Wound core – distributed gap; or stacked butt-lap; Shell-type or core-type
6	3	Wound core - distributed gap; step-lap or full mitered; 3-leg or 5-leg
8	3	Wound core - distributed gap; or stacked butt-lap, step-lap or full mitered; 3-leg or 5-leg
9	3	Wound core - distributed gap; or stacked full mitered; 3-leg or 5-leg
10	3	Wound core – distributed gap; or stacked, cruciform, mitered joint; 3-leg
11	3	Wound core – distributed gap; or stacked, step-lap or full mitered; 3-leg or 5-leg
12	3	Wound core – distributed gap; or stacked, cruciform or step-lap mitered joint; 3-leg or 5-leg
13	3	Wound core – distributed gap; or stacked, cruciform or step-lap mitered joint; 3-leg or 5-leg
14	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

The choice of a distribution transformer core configuration can impact both the cost and efficiency of a distribution transformer. Certain core designs that have increased stresses (in the form of bends in the electrical steel, gaps, *etc*.) can lead to increased core losses. More advanced core designs, for example transitioning from butt-lap cores to step-lap miter cores, can lead to increased efficiency. However, the retooling and capital costs associated with more efficient designs may impact the cost of a given distribution transformer core design. Further some core designs may not be suitable for certain core steels. For example, amorphous steel can only be used in wound core designs.

In this analysis, for the single-phase representative units, the most common configuration is a wound-core. Whether wound or stacked, however, the single-phase cores may be of either a shell- or core-type core. 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 5.3.2 illustrates the two types of single-phase core construction.

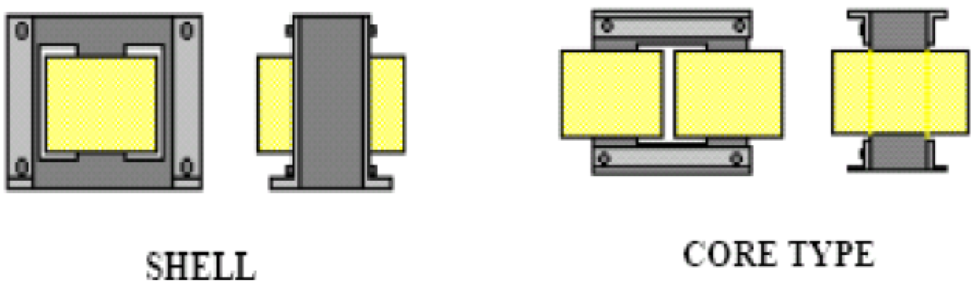


Figure 5.3.2 Graphic of Single-Phase Core Configurations

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 5.3.3 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, 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.

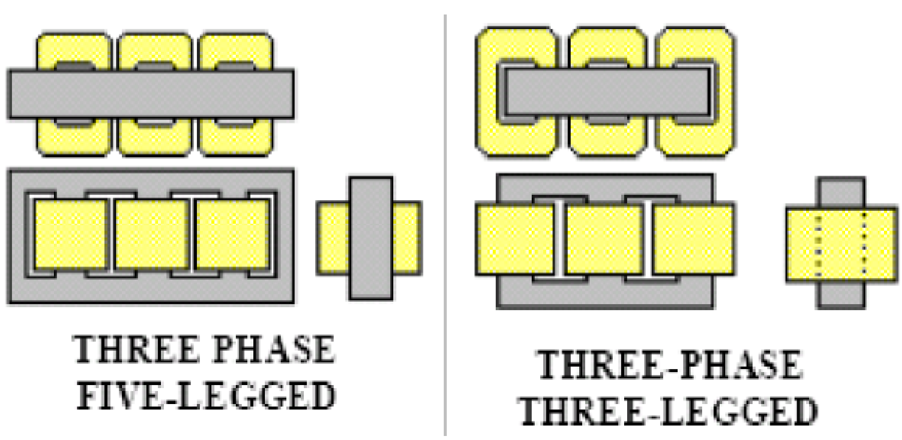


Figure 5.3.3 Graphic of Three-phase Core Configurations

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 5.3.4 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.

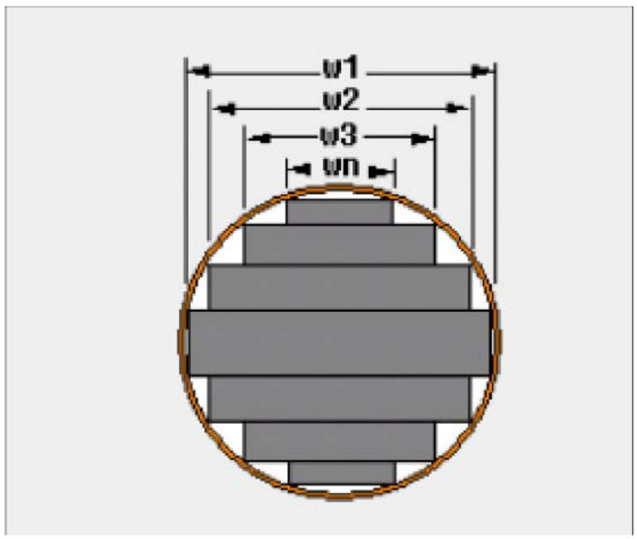


Figure 5.3.4 Cruciform Core Cross-Section

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.

5.3.4 Representative Unit 1

Representative unit 1 (RU1) represents small kVA, rectangular-tank, liquid-immersed, single-phase distribution transformers. The configuration selected for this RU 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 RU1, DOE selected eleven 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. Except for the max-tech/high efficiency designs, DOE selected nine design option combinations to represent the most common construction practices for this representative unit.

Table 5.3.5 Design Option Combinations for Representative Unit 1

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
23hib090	Al – wire	Al – strip	Shell – DG Wound Core
23pdr085	Al – wire	Al – strip	Shell – DG Wound Core
23pdr085	Cu – wire	Cu – strip	Shell – DG Wound Core
23pdr075	Al – wire	Al – strip	Shell – DG Wound Core
am	Al – wire	Al – strip	Shell – DG Wound Core
am	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 eleven design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 1841 designs compliant with current energy conservation standards.

5.3.5 Representative Unit 2

Representative unit 2 (RU2) represents small kVA, round-tank, liquid-immersed, single-phase distribution transformers. The configuration selected for this RU is a 25 kVA 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 RU2, DOE selected ten design option combinations, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practices for the representative unit.

Table 5.3.6 Design Option Combinations for Representative Unit 2

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
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
23hib090	Al – wire	Al – strip	Shell – DG Wound Core
23pdr085	Al – wire	Al – strip	Shell – DG Wound Core
23pdr085	Cu – wire	Cu – strip	Shell – DG Wound Core
23pdr075	Al – wire	Al – strip	Shell – DG Wound Core
am	Al – wire	Al – strip	Core – DG Wound Core
am	Cu – wire	Cu – strip	Core – DG Wound Core

DOE analyzed each of the ten design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 1952 designs compliant with current energy conservation standards.

5.3.6 Representative Unit 3

Representative unit 3 (RU3) represents large kVA, liquid-immersed, single-phase distribution transformers. The configuration selected for this RU is a 500 kVA 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 RU3, DOE selected twelve design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE chose design option combinations to represent the most common construction practice for this representative unit.

Table 5.3.7 Design Option Combinations for Representative Unit 3

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M4	Al – 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
23hib090	Al – wire	Al – strip	Shell – DG Wound Core
23pdr085	Al – wire	Al – strip	Shell – DG Wound Core
23pdr085	Cu – wire	Cu – strip	Shell – DG Wound Core
23pdr075	Al – wire	Al – strip	Shell – DG Wound Core
am	Al – wire	Al – strip	Core – DG Wound Core
am	Cu – wire	Cu – strip	Shell – DG Wound Core
am	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 5.3.1 and Table 5.3.2, creating 2189 designs compliant with current energy conservation standards.

5.3.7 Representative Unit 4

Representative unit 4 (RU4) represents small kVA, rectangular tank, liquid-immersed, three-phase distribution transformers. The configuration selected for this RU is a 150 kVA 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 RU4, DOE selected eleven design option combinations of core steel and winding types based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.8 Design Option Combinations for Representative Unit 4

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
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
23hib090	Al – wire	Al – strip	5-Leg DG Core
23pdr085	Al – wire	Al – strip	5-Leg DG Core
23pdr085	Cu – wire	Cu – strip	5-Leg DG Core
23pdr075	Al – wire	Al – strip	5-Leg DG Core
am	Al – wire	Al – strip	5-Leg DG Core
am	Cu – wire	Cu – strip	5-Leg DG Core
am	Al – wire	Al – strip	Evans Core

DOE analyzed each of the eleven design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 1829 designs compliant with current energy conservation standards.

5.3.8 Representative Unit 5

Representative unit 5 (RU5) represents large kVA, rectangular tank, liquid-immersed, three-phase distribution transformers. The configuration selected for this RU is a 1500 kVA 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 RU5, DOE selected twelve design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practices for the representative unit.

Table 5.3.9 Design Option Combinations for Representative Unit 5

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
23hib090	Al – wire	Al – strip	5-Leg DG Core
23pdr085	Al – wire	Al – strip	5-Leg DG Core
23pdr085	Cu – wire	Cu – strip	5-Leg DG Core
23pdr075	Al – wire	Al – strip	5-Leg DG Core
am	Al – wire	Al – strip	5-Leg DG Core
am	Cu – wire	Cu – strip	5-Leg DG Core
am	Al – wire	Al – strip	Evans Core

DOE analyzed each of the twelve design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 916 designs compliant with current energy conservation standards.

5.3.9 Representative Unit 6

Representative unit 6 (RU6) represents ventilated dry-type, single-phase, low-voltage distribution transformers. The configuration selected for this RU 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; 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 RU6, DOE selected sixteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.10 Design Option Combination for Representative Unit 6

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
23hib090	Al – wire	Al – strip	Step-Lap Miter
23dr080	Al – wire	Al – strip	Stacked Core Butt-lap
23dr080	Cu – wire	Cu – wire	Stacked Core Butt-lap
23dr080	Al – wire	Al – strip	Step-Lap Miter
23dr075	Al – wire	Al – strip	Step-Lap Miter
20dr070	Al – wire	Al – strip	Step-Lap Miter
23pdr085	Al – wire	Al – strip	Core – DG Wound Core
23pdr075	Al – wire	Al – strip	Core – DG Wound Core
am	Al – wire	Al – strip	Core – DG Wound Core
am	Cu – wire	Cu – wire	Core – DG Wound Core

DOE analyzed each of the sixteen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 6,807 designs compliant with current energy conservation standards.

5.3.10 Representative Unit 7

Representative unit 7 (RU7) represents a small kVA, ventilated dry-type, three-phase, low-voltage distribution transformers. The configuration selected for this RU 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 RU7, DOE selected fifteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.11 Design Option Combinations for Representative Unit 7

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M6	Al – wire	Al – wire	3-Leg Stacked Full Miter*
M4	Al – wire	Al – wire	3-Leg Stacked Butt-lap
M4	Al – wire	Al – wire	3-Leg Step-Lap 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
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Stacked Full Miter
23dr080	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Cu – wire	Cu – wire	3-Leg Stacked Full Miter
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
23pdr085	Al – wire	Al – strip	3-Leg DG Core
am	Al – wire	Al – strip	5-Leg DG Core
am	Cu – wire	Cu – wire	5-Leg DG Core

* Full miters are not step-miters, but rather mitered joints for all three legs. These cores are stacked three by three.

DOE analyzed each of the fifteen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 5722 designs compliant with current energy conservation standards.

5.3.11 Representative Unit 8

Representative unit 8 (RU8) represents large kVA ventilated dry-type, three-phase, low-voltage distribution transformers. The configuration selected for this RU 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 RU8, DOE selected seventeen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.12   Design Option Combinations for Representative Unit 8

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
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 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	Al – wire	Al – strip	DG Wound Core
M3	Cu – wire	Al – strip	3-Leg Stacked Full Miter
23hib090	Al – wire	Al – strip	5-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Stacked Full Miter
23dr080	Al – wire	Al – strip	5-Leg Step-Lap Miter
23dr080	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
23dr075	Al – wire	Al – strip	5-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	5-Leg Step-Lap Miter
23pdr085	Al – wire	Al – strip	DG Wound Core
am	Al – wire	Al – strip	5-Leg DG Core
am	Cu – wire	Cu – strip	5-Leg DG Core

* 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 seventeen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 4,863 designs compliant with current energy conservation standards.

5.3.12 Representative Unit 9

Representative unit 9 (RU9) represents small kVA, ventilated dry-type, three-phase, medium-voltage distribution transformers with a 20-45 kV BIL. The configuration selected for this RU 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 RU9, DOE selected seventeen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.13 Design Option Combinations for Representative Unit 9

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
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Stacked Full Miter
23dr080	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
23pdr085	Al – wire	Al – strip	5-Leg DG Core
am	Al – wire	Al – strip	5-Leg DG Core
am	Cu – wire	Cu – strip	3-Leg DG Core
am	Cu – wire	Cu – strip	5-Leg DG Core

* 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 seventeen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 6,867 designs compliant with current energy conservation standards.

5.3.13 Representative Unit 10

Representative unit 10 (RU10) represents large kVA dry-type, three-phase, medium-voltage distribution transformers with a 20-45 kV BIL. The configuration selected for this RU 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 RU10, DOE selected fourteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.14 Design Option Combinations for Representative Unit 10

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
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Mitered Cruciform
23dr080	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Cu – wire	Cu – strip	3-Leg Mitered Cruciform
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
am	Al – wire	Al – strip	5-Leg DG Core
am	Cu – wire	Cu – strip	3-Leg DG Core

DOE analyzed each of the fourteen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 2,422 designs compliant with current energy conservation standards.

5.3.14 Representative Unit 11

Representative unit 11 (RU11) represents small kVA, dry-type, three-phase, medium-voltage distribution transformers with a 46-95 kV BIL. The configuration selected for this RU 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 RU11, DOE selected fifteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.15 Design Option Combinations for Representative Unit 11

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
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Stacked Full Miter
23dr080	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Cu – wire	Cu – strip	3-Leg Stacked Full Miter
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
23pdr085	Al – wire	Al – strip	3-Leg DG Core
am	Al – wire	Al – strip	3-Leg DG Core
am	Cu – wire	Cu – strip	5-Leg DG Core

* Full miters are not step-miters, but rather mitered joints for all three legs. These cores are stacked three by three.

DOE analyzed each of the fifteen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 2,480 designs compliant with current energy conservation standards.

5.3.15 Representative Unit 12

Representative unit 12 (RU12) represents large kVA, dry-type, three-phase, medium-voltage distribution transformers with a 46-95kV BIL. The configuration selected for this RU 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 RU12, DOE selected thirteen design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.16 Design Option Combinations for Representative Unit 12

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
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
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Mitered Cruciform
23dr080	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Cu – wire	Cu – strip	3-Leg Mitered Cruciform
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
am	Al – wire	Al – strip	5-Leg DG Core
am	Al – wire	Al – strip	Evans Core
am	Cu – wire	Cu – strip	5-Leg DG Core

DOE analyzed each of the thirteen design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 3,503 designs compliant with current energy conservation standards.

5.3.16 Representative Unit 13

Representative unit 13 (RU13) represents small kVA, dry-type, three-phase, medium-voltage distribution transformers with a ≥ 96kV BIL. The configuration selected for this RU 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 RU13, DOE selected eleven design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.17 Design Option Combinations for Representative Unit 13

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
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23pdr085	Al – wire	Al – strip	3-Leg DG Core
23dr080	Al – wire	Al – strip	3-Leg Mitered Cruciform
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
am	Al – wire	Al – strip	5-Leg DG Core

DOE analyzed each of the eleven design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 1,214 designs compliant with current energy conservation standards.

5.3.17 Representative Unit 14

Representative unit 14 (RU14) also represents large kVA, dry-type, three-phase, medium-voltage distribution transformers with a ≥ 96kV BIL. The configuration selected for this RU 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 RU14, DOE selected eight design option combinations of core steel and winding material, based on input from manufacturers and other technical experts. Except for the max-tech/high-efficiency designs, DOE selected these design option combinations to represent the most common construction practice for the representative unit.

Table 5.3.18 Design Option Combinations for the Representative Unit 14

Core Material	High-Voltage Conductor	Low-Voltage Conductor	Core Design Type
M3	Al – wire	Al – strip	3-Leg Mitered Cruciform
M3	Al – wire	Al – strip	3-Leg Step-Lap Miter
23hib090	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr080	Al – wire	Al – strip	3-Leg Mitered Cruciform
23dr080	Al – wire	Al – strip	3-Leg Step-Lap Miter
23dr075	Al – wire	Al – strip	3-Leg Step-Lap Miter
20dr070	Al – wire	Al – strip	3-Leg Step-Lap Miter
am	Al – wire	Al – strip	5-Leg DG Core

DOE analyzed each of the eight design option combinations using the matrix of A and B values described in Table 5.3.1 and Table 5.3.2, creating 1,568 designs compliant with current energy conservation standards.

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.

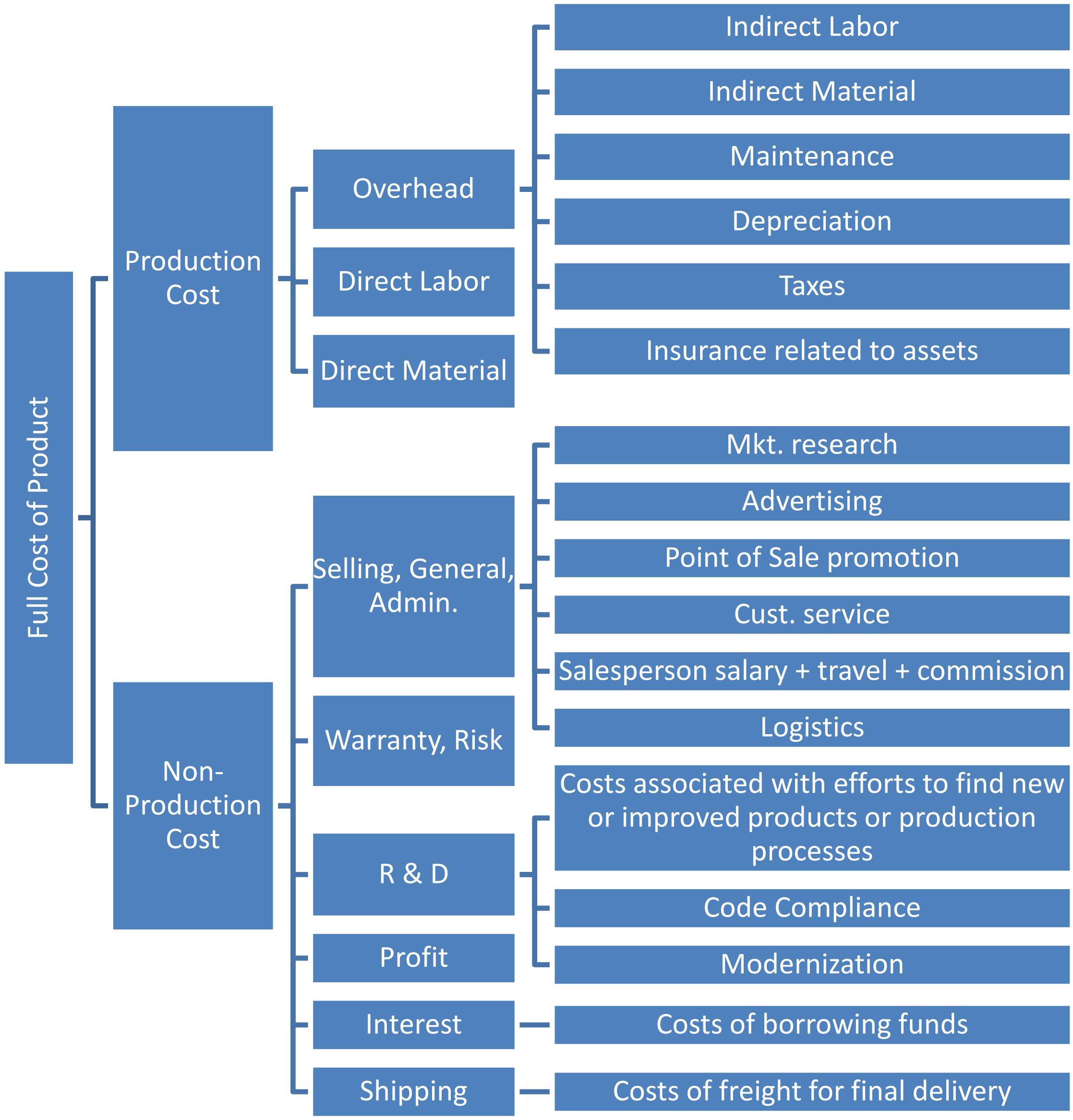


Figure 5.4.1 Method of Cost Account for Distribution Transformers Rulemaking

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 developed several estimates of the costs listed in Figure 5.4.1 as part of its 2013 standards rulemaking. The estimates relied on U.S. Industry Census Data Reports, manufacturer interviews, and Securities and Exchange Commission (SEC) 10-K reports for several manufacturers. For this analysis, DOE confirmed that these markups were still accurate through meetings and dialogue with transformer manufacturers in 2019 and 2020. 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. Based on conversations with manufacturers, shipping cost is not typically calculated on a per-pound basis. Rather, it is a less well-defined function of several factors, including weight, volume, footprint, order size, destination, distance, and other, general shipping costs (fuel prices, drive wages, demand, etc.). However, based on manufacturer interview feedback, a price-per-pound estimate is an appropriate approximation of sipping costs because it reflect an increased shipping cost associated with larger distribution transformers (*i.e.*, where fewer would fit on a truck). DOE applied the shipping charge prior to applying the non-production mark-up.

- 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, factory overhead, and shipping costs.

The following example shows how DOE applied the markups to the materials, and how it determined the manufacturer selling price. Consider a RU4 distribution transformer designed with a $7.00 A and a $5.60 B. This design has $3,751 of materials, including a distributed gap wound M3 steel core, copper primary and aluminum secondary windings, and all the transformer hardware. There are approximately 5.6 hours of labor involved in manufacturing this design, resulting in a labor cost of $501.84 (labor costs here include the 25 percent non-production markup and handling and slitting costs). The factory overhead on this design is $469, as it is only applied to the material cost (*i.e.*, 12.5 percent of $3,751). The shipping cost is $901, based on a weight of 3,220 pounds. The non-production cost is $1,280, since the 25 percent is applied to the material, factory overhead, and shipping costs (i.e., 25 percent of $3,751 + $469 + $901). Thus, in total, DOE estimates this distribution transformer to have a manufacturer selling price of $6,904.

5.4.1 Material Prices

DOE conducted the engineering analysis by applying materials prices to the distribution transformer designs modeled by OPS. The primary material costs in distribution transformers come from electrical steel used for the core and the aluminum and copper conductor used for the primary and secondary windings. Material pricing is critical to the cost-efficiency of different design options 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 core steel and pounds of conductor. Therefore, as material prices increase, so will the manufacturer's selling price. Furthermore, as discussed in chapter 3, more efficient transformers (of similar specification) 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.

Material prices can vary significantly by manufacturer. For example, not all transformer manufacturers pay the same amount per pound for electrical-grade steels, due to varied contract negotiations. As such, the prices DOE used in this analysis are intended to be representative of a standard quantity order for a medium- to large-scale U.S. based distribution transformer manufacturer.

5.4.1.1 Conductor Prices

Aluminum and copper are the materials used as conductors. The prices of aluminum and copper conductor are strongly correlated to the price of the underlying commodities, which are tracked in various public indices. DOE initially developed price estimates based on London Metal Exchange (LME) and CME Group (*e.g.*, COMEX) to extrapolate material prices from 2010 to the present. DOE presented these initial estimates to manufacturers in interviews and adjusted its price estimates in response to manufacturer feedback.

Manufacturers also commented that there is a 10 percent *ad valorem* tariff on aluminum produced from certain countries. However, manufacturers indicated some ability to partially mitigate the impact of these tariffs by changing suppliers to those that do not have to pay the tariff. In DOE's base pricing scenario, it assumed that the 10 percent aluminum tariff would be partially offset by changes in sourcing, supplier's absorbing some cost, and a reduced demand for aluminum throughout the market. Therefore, in the base-case price scenario, DOE assumed the realized price increase for distribution transformer manufacturers would be 7.5 percent as a result of the aluminum tariff. DOE also conducted two additional sensitivity analysis related to electrical steel tariffs (described in section 5.4.1.1). In these sensitivity analysis, DOE assumed that the aluminum tariffs were no longer present. The conductor prices used in this analysis are presented in Table 5.4.1.

Table 5.4.1 Conductor Prices

Item and description	Base Case ($/lb)	No Tariffs Case ($/lb)	Expanded Core Tariff Case ($/lb)
Copper wire, formvar, round #10-20	$3.89	$3.89	$3.89
Copper wire, enameled, round #7-10	$4.03	$4.03	$4.03
Copper wire, enameled, rectangular sizes	$4.22	$4.22	$4.22
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped	$3.89	$3.89	$3.89
Copper strip, thickness range 0.02-0.045	$3.75	$3.75	$3.75
Copper strip, thickness range 0.030-0.060	$3.59	$3.59	$3.59
Aluminum wire, formvar, round #9-17	$3.75	$3.49	$3.49
Aluminum wire, formvar, round #7-10	$3.20	$2.97	$2.97
Aluminum wire, rectangular #<7	$3.49	$3.25	$3.25
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped	$2.27	$2.12	$2.12
Aluminum strip, thickness range 0.02-0.045	$1.67	$1.55	$1.55
Aluminum strip, thickness range 0.045-0.080	$1.70	$1.58	$1.58

5.4.1.1 Electrical Steel Prices

The other major material cost for distribution transformers is the cost of the core electrical steel. While the price of steel often moves with the commodity market, electrical steel tends to move separately and independently. In interviews, manufacturers stressed that the price of electrical steel is largely contract based. Therefore, for a given steel grade, the price can vary widely between manufacturers depending on the electrical steel supplier, quantity ordered, and other contract specifications. In certain cases, a distribution transformer manufacturer may not have ready access to all steel grades due to the varying technological capabilities and capacities of the electrical steel supplier that serves them.

The prices of electrical steels have experienced more variation following the implementation of a 25 percent *ad valorem* tariff of all raw imported electrical steel. Manufacturer responses in DOE interviews and in comments to a Department of Commerce investigation of imparts of laminations for stacked cores (BIS-2020-0015), indicated an ability to partially mitigate the impact of tariffs by either purchasing finished cores, off-shoring their own core manufacturing, or purchasing domestically produced electrical steel[e].

In generating electrical steel prices for use in this analysis, DOE relied on a well-known steel market data vendor, supplemented with manufacturer interviews to derive prices for the various steel grades. DOE assumed that the 25 percent steel tariff would be partially mitigated

[e] AK Steel, BIS-2020-0015-0075. Available at: https://www.regulations.gov/document/BIS-2020-0015-0075

via changes in sourcing and purchasing. Therefore, in the base-case scenario, DOE assumed the tariffs increased the cost of all electrical steels by 18.8 percent.

DOE also conducted two price sensitivity scenarios. In the first scenario, the “No Tariff” case, DOE assumed there was no tariff on any electrical steels. In the second scenario, the “Expanded Core Tariff” case, DOE assumed that the 25 percent tariff was expanded laminations and finished cores. As such, DOE assumed that there was no ability for manufacturers to mitigate the 25 percent tariff and therefore applied the full 25 percent tariff to all electrical steel prices.

While amorphous steel core production has increased since the April 2013 Standards Final Rule, manufacturers commented that in most cases, manufacturers are purchasing amorphous steel as finished cores rather than as raw amorphous steel. Therefore, in this analysis, DOE assumed that amorphous steel was purchased as a finished core. As such, the cost of amorphous steel used in this analysis is higher than it would be to purchase raw amorphous steel. However, DOE does not include the core steel scrap adder since the cores were assumed to be purchased as a finished product. DOE also assumed that the electrical steel tariffs impacted amorphous steel in an identical way to conventional electrical steel. The base material prices and sensitivity material prices are shown in Table 5.4.2.

Table 5.4.2 Electrical Steel Material Prices

Item and description	Base Case ($/lb)	No Tariffs Case ($/lb)	Expanded Core Tariff Case ($/lb)
Grain-Oriented Electrical Steel			
M6	$1.13	$0.95	$1.19
M5	$1.10	$0.92	$1.15
M4	$1.11	$0.93	$1.16
M3	$1.30	$1.10	$1.37
M2	$1.43	$1.20	$1.50
High-Permeability Grain-Oriented Electrical Steel			
23hib090	$1.28	$1.08	$1.35
23pdr085 (permanently domain-refined)	$1.52	$1.28	$1.60
23dr080 (domain-refined)	$1.42	$1.20	$1.50
23pdr075 (permanently domain-refined)	$1.69	$1.43	$1.78
23dr075 (domain-refined)	$1.69	$1.35	$1.69
20dr070 (domain-refined)	$1.71	$1.44	$1.80
Amorphous Electrical Steel (Finished Cores)			
am	$1.84	$1.55	$1.94

In summary, DOE conducted the engineering analysis using material prices (in constant 2020-year US dollars). Using the material prices from this period, DOE considered a base case (2020) material price, a no tariff price sensitivity case, and an expanded core tariff 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. The no tariff and expanded tariff prices were then applied to the same OPS generated designs to generate a manufacturer selling price for each of those scenarios. The results of the base case material prices are presented here in chapter 5, whereas the results of the no tariff and expanded core tariff case material prices are presented in Appendix 5B.

DOE noted that the price of the most critical material input to a distribution transformer, electrical core steel, can vary significantly for some electrical steels. For this reason, DOE researched the electrical steel market to gain a better understanding of the main players and some of the factors influencing these price fluctuations (see Appendix 3A).

5.4.1.2 Electrical Steel Miter Core Adders

In the April 2013 Standard Final Rule, DOE incorporated a core steel processing adder for mitered core designs of low- and medium-voltage dry-type distribution transformers. 78 FR 23336, 23368. These processing adders were designed to represent the additional cost per pound associated with mitering. As such, for medium-voltage dry-type distribution transformers, DOE incorporated a processing adder of 10 cents per pound for step-lap mitering. For low-voltage dry-type distribution transformers, DOE incorporated a processing adder of 20 cents per pound for step-lap mitering and 10 cents per pound for ordinary mitering. This is consistent with the previous rulemaking. Also, the OPS software does not take into account retooling costs associated with changing production design. Therefore, to partially capture these differential costs in the design lines that had both buttlap and mitered designs, DOE used adders in RU7 and RU8.

Table 5.4.3 Electrical Steel Miter Core Adders

Core Design	RU6	RU7	RU8	RU9	RU10	RU11	RU12	RU13	RU14
SLM ($/lb)	$0.20	$0.21	$0.31	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10
FM/CM ($/lb)	$0.10	$0.21	$0.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

5.4.1.3 Scrap Factor Markups

DOE applies a variety of core assembly markups depending on the type of steel used in each design option combination. These markups are designed to account for the steel scrap that is lost in the construction of distribution transformer cores. The percentages were developed from manufacturer input and are described in detail below.

- Handling and Slitting: 1.5 percent. 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 distribution transformer (*e.g.,* lengths of wire too short to wind, trimmed core steel).

- Scrap Factor: 1.0 percent. 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 distribution transformer (*e.g.,* lengths of wire too short to wind, trimmed core steel).
- Amorphous Scrap Factor: 1.5 percent. 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. An additional scrap markup applies to steel used in mitered or cruciform cores.

For conventional electrical steel, DOE applied the scrap factor and handling and slitting factor to the material costs of the core steel, winding and insulation. In cases where a mitered core is used, DOE also applied a mitered scrap factor on the core steel costs, in addition to the scrap factor and handing and slitting factor. If an amorphous core is used, DOE assumed that the core was sourced rather than manufactured in-house. Therefore, DOE applied an amorphous scrap factor that accounts for any scrap associated with the breakage of prefabricated cores along with any scrap associated with assembling the windings or insulation on the cores.

5.4.1.4 Other Material Prices

In addition to the primary material costs (electrical steel and conductors), DOE also updated the prices for the other variable components including insulating material, mineral oil, winding combs, and tank/enclosure steel. DOE relied on inflators and feedback from manufacturers to derive updated prices for these material. In addition, the manufacturers stated that tank and enclosure steel would be subject to the 25 percent steel tariffs. As such, DOE has applied varied the price of tank/enclosure steel in the no tariffs case and expanded core tariff case, similar to what was done with the electrical steel tariffs.

Item and description	Base Case ($/lb)	No Tariffs Case ($/lb)	Expanded Core Tariff Case ($/lb)
Nomex Insulation[f]	$28.24	$28.24	$28.24
Kraft insulating paper with diamond adhesive	$2.08	$2.08	$2.08
Mineral oil	$2.76	$2.76	$2.76
Impregnation	$25.99	$25.99	$25.99
Winding Combs	$14.22	$14.22	$14.22
Tank/Enclosure Steel	$0.35	$0.30	$0.37

5.4.2 Material Price Software Inputs – Liquid-Immersed

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 5.4.4 summarizes all the estimated fixed material costs and estimates of the tank costs for each of the five liquid-immersed RUs.

For RU1, a 50kVA single-phase pad-mounted unit, the high-voltage bushings are two universal bushing wells, 15 kV, 95 BIL, 14400V, costing $15.40 each. The low-voltage bushings are three threaded copper studs, 240/120V, 50 kVA, costing $33.01 for the set. Internal hardware costs include a core clamp, nameplate, and other miscellaneous hardware costing $47.55. The finished tank size (and associated cost) varies by design and include a 16” flip top pad door, but the average cost is approximately $150.40.

For RU2, a 25kVA single-phase pole-mounted unit, the high-voltage terminal is a single, wet-process porcelain bushing assembly, 15 kV, 125 BIL, costing $6.85. The low-voltage terminals are three molded polymer bushings, 120/240V, 25 kVA, costing $9.13 for the set. Internal hardware costs include a core clamp, nameplate, and other miscellaneous hardware, costing $21.86. The finished tank sizes (height and diameter) vary by design, but the average cost is approximately $79.80.

For RU3, a 500kVA single-phase unit, the high-voltage connector is a single, wet-process porcelain bushing, 25 kV, 125 BIL, costing $6.85. The low-voltage bushings are two four-hole “J” Spade 500kVA, 277V, costing $68.05 for the set. The internal hardware includes a core clamp ($34.25), nameplate ($0.74), and miscellaneous hardware ($22.83), totaling $57.83. The design software optimized the tank cost with each design, including radiators (external cooling)

[f] While other insulation materials could be used for dry-type distribution transformers, this analysis assumed only Nomex insulation due to its combination of tensile strength and thermal aging resistance ability allowing it to be representative of many different applications. This is consistent with the April 2013 Final Rule

for this kVA rating. The finished tank sizes (height and diameter) vary by design and, if needed, include radiators, with an average cost of approximately $668.80 (including radiators).

For RU4, 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 $23.98 total. The low-voltage bushings are three copper studs at $27.40 total. The internal hardware includes core clamps ($34.25), nameplate ($0.74), and miscellaneous hardware ($51.38), totaling $86.37. The finished tank sizes (and associated costs) vary by design and include a pad cabinet in front of the tank. The finished rectangular, welded tank has an average cost of approximately $391.98.

For RU5, 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 $68.50 total. The low-voltage bushings are four externally clamped bushings, each having six-hole spade, costing $182.68 for the set. The internal hardware includes core clamps ($68.50), nameplate ($0.74), and miscellaneous hardware ($51.38), totaling $120.62. The finished tank sizes (and associated costs) vary by design, include a pad cabinet in front of the tank, and, if needed, radiators. The finished rectangular, welded tank, including radiators as specified by the design software, has an average cost of approximately $881.63.

Table 5.4.4 Summary Table of Fixed Material Costs for Liquid-Immersed Units

Item	RU1	RU2	RU3	RU4	RU5
High voltage bushings	$30.80	$6.85	$6.85	$23.98	$68.50
Low voltage bushings	$33.01	$9.13	$68.50	$27.40	$182.68
Core clamp, nameplate, and misc. hardware	$47.55	$21.86	$57.83	$86.37	$120.62
Transformer tank average cost*	$150.40	$79.80	$668.80	$391.98	$881.63

* Transformer tank steel is used in the design optimization software and varies with the efficiency (and size) of each design. RU3 and RU5 include calculated costs of radiators, which are scaled for each design based on the required cooling surface area.

5.4.3 Material Price Software Inputs – Dry-Type

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 5.4.5.

For RU6, a 25 kVA single-phase, low-voltage, dry-type transformer, the low-voltage and high-voltage terminal set costs $4.57. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $10.56 The fiberglass dog-bone duct-spacers used for this RU cost $0.27 per foot. DOE estimated the miscellaneous hardware costs at $5.14. 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 $73.99

For RU7, a 75 kVA three-phase, low-voltage, dry-type transformer, the fixed hardware costs are $30.83 for the high-voltage terminal board with connection points. DOE estimated the secondary (low-voltage) bus-bar to be seven feet for $11.99. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $21.69. The fiberglass dog-bone duct-spacers used for this RU cost $0.37 per foot. DOE estimated the miscellaneous hardware costs at $7.99. 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 $148.08.

For RU8, a 300 kVA three-phase, low-voltage, dry-type transformer, the high-voltage terminal board costs $30.83. DOE estimated the secondary (low-voltage) bus-bar to be nine feet for $25.69. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $41.10. The fiberglass dog-bone duct-spacers used for this RU cost $0.48 per foot. DOE estimated the miscellaneous hardware costs at $13.70. 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 $190.44.

For RU9, a 300 kVA three-phase, medium-voltage, dry-type transformer at 45 kV BIL, the low-voltage and high-voltage terminal set costs $85.63. DOE estimated the secondary (low-voltage) bus-bar to be eight feet for $91.34. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $41.10. The fiberglass dog-bone duct-spacers used for this RU cost $0.48 per foot. DOE estimated the miscellaneous hardware costs at $28.54. 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 $253.91.

For RU10, a 1500 kVA three-phase, medium-voltage, dry-type transformer at 45 kV BIL, the low-voltage and high-voltage terminal set costs $137.01. DOE estimated the low-voltage bus-bar to be 14 feet for $159.84. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs approximately $137.01. 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 RU10 (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 572 pounds on average and costs approximately $202.61. The fiberglass dog-bone duct-spacers used for this RU cost $0.59 per foot. DOE estimated the miscellaneous hardware costs at $47.95. 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 $764.79.

For RU11, a 300 kVA three-phase, medium-voltage, dry-type at 95 kV BIL, the low-voltage and high-voltage terminal set costs $114.17. The high-voltage terminal boards cost $30.83. DOE estimated the low-voltage bus-bar is estimated to be 10 feet for $91.34. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $47.95. The fiberglass dog-bone duct-spacers used for this RU cost $0.48 per foot. DOE estimated the miscellaneous hardware costs at $36.54. 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 $409.59.

For RU12, a 1500 kVA three-phase, medium-voltage, dry-type at 95 kV BIL, the low-voltage and high-voltage terminal set costs $154.13. The high-voltage terminal boards cost

$30.83. DOE estimated the low-voltage bus-bar is estimated to be 16 feet for $219.21. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $142.72. 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 RU12 (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 629 pounds on average and costs approximately $222.60. The fiberglass dog-bone duct-spacers used for this RU cost $0.64 per foot. DOE estimated the miscellaneous hardware costs at $61.65. 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 $854.76.

For RU13, a 300 kVA three-phase, medium-voltage, dry-type at 125 kV BIL, the low-voltage and high-voltage terminal set costs $131.30. The high-voltage terminal boards cost $30.83. DOE estimated the low-voltage bus-bar is estimated to be 10 feet for $114.17. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $57.09. The fiberglass dog-bone duct-spacers used for this RU cost $0.48 per foot. DOE estimated the miscellaneous hardware costs at $31.10. 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 $546.50.

For RU14, a 2000 kVA three-phase, medium-voltage, dry-type at 125 kV BIL, the low-voltage and high-voltage terminal set costs $171.26. The high-voltage terminal boards cost $30.83. DOE estimated the low-voltage bus-bar is estimated to be 18 feet for $308.27. The mounting frame that attaches the core/coil assembly to the transformer enclosure costs $199.80. 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 RU14 (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 813 pounds on average and costs approximately $287.88. The fiberglass dog-bone duct-spacers used for this RU cost $0.69 per foot. DOE estimated the miscellaneous hardware costs at $68.50. 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 $963.98.

Table 5.4.5 Summary Table of Fixed Material Costs for Dry-Type Units

Item	RU6	RU7	RU8	RU9	RU10	RU11	RU12	RU13	RU14
LV* and HV* terminals (set)	$4.57	n/a	n/a	$85.63	$137.01	$114.17	$154.13	$131.30	$171.26
HV* terminal board(s)	n/a	$30.83	$30.83	$30.83	$30.83	$30.83	$30.83	$30.83	$30.83
LV* busbar	n/a	$11.99	$25.69	$91.34	$159.84	$91.34	$219.21	$114.17	$308.27

Core/coil mounting frame	$10.56	$21.69	$41.10	$41.10	$137.01	$47.95	$142.72	$57.09	$199.80
Additional Bracing Average	n/a	n/a	n/a	n/a	$202.61	n/a	$222.60	n/a	$187.88
Nameplate	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74
Dog-bone duct spacer (ft.)	$0.27	$0.37	$0.48	$0.48	$0.59	$0.48	$0.64	$0.48	$0.69
Winding combs (lb.)	n/a	n/a	n/a	n/a	n/a	$14.09	$14.09	$14.09	$14.09
Misc. hardware	$5.14	$7.99	$13.70	$28.54	$47.95	$36.54	$61.65	$41.10	$68.50
Enclosure (14, 16 gauge)	$73.99	$148.08	$190.44	$253.91	$764.59	$409.59	$854.76	$546.50	$963.98

*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 initially updated its labor rate estimate based on U.S. Bureau of Labor Statistics rates for North American Industry Classification System ("NAICS")[g] Code 335311- "Power, Distribution, and Specialty Transformer Manufacturing" production employee hourly rates and applied mark-ups for indirect production, overhead, fringe, assembly labor up-time, and a nonproduction mark-up to get a fully burdened cost of labor. DOE then presented this value to manufacturers who thought it was approximately representative, but potentially too low . In this preliminary analysis, DOE revised their base labor rate estimate to get a fully burdened labor cost of $82.14 as shown in Table 5.4.6.

[g] NAICS is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy.
NAICS relies on a production-oriented or supply-based conceptual framework that groups establishments into industries according to similarity in the processes used to produce goods or services. *See*, https://www.census.gov/eos/www/naics/2017NAICS/2017_NAICS_Manual.pdf.

Table 5.4.6 Labor Markups for Liquid-Immersed and Dry-Type Manufacturers

Item description	Markup percentage	Rate per hour
Labor cost per hour*		$21.43
Indirect Production**	33%	$28.51
Overhead***	30%	$37.06
Fringe†	24%	$45.95
Assembly Labor Uptime††	43%	$65.71
Fully-burdened Cost of Labor	25%	$82.14

* NAICS is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy. NAICS relies on a production-oriented or supply-based conceptual framework that groups establishments into industries according to similarity in the processes used to produce goods or services. See, https://www.census.gov/eos/www/naics/2017NAICS/2017_NAICS_Manual.pdf.
** Indirect production labor (e.g., production managers, quality control) as a percent of direct labor on a cost basis. Guidehouse Consulting, Inc. (Guidehouse) estimate.
*** Overhead includes commissions, dismissal pay, bonuses, vacation, sick leave, and social security contributions. Guidehouse estimate.
† Fringe includes pension contributions, group insurance premiums, workers compensation. Total fringe benefits as a percent of total compensation for all employees (not just production workers). Maintained from April 2013 Standards Final Rule
†† 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). Guidehouse estimate.

5.4.5 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 5.4.7.

5.4.5.1 Fixed Labor Costs (hours)

- 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 RU1, RU2, and RU4, 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 RU3 and RU5, 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 RU1, RU2, and RU4, the hours per turn of the secondary are 0.015 (54 seconds per turn); for RU3 and RU5, 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.

- 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 representative units 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 and shape, 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 5.4.7 summarizes the estimates of labor time that DOE used for the five liquid-immersed units.

Table 5.4.7 Summary of Fixed Labor Times for Liquid-Immersed Units

Labor Activity	RU1 hrs	RU2 hrs	RU3 hrs	RU4 hrs	RU5 hrs
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 (hrs)	0.50	0.1	0.35	0.75	1.00
Coil Varnishing and Baking (hrs)	0.10	0.07	0.15	0.17	0.25
Tanking and Impregnating (hrs)	0.30	0.11	0.65	0.50	1.80
Inspection (hrs)	0.10	0.05	0.10	0.15	0.20
Preliminary Test (hrs)	0.10	0.05	0.10	0.10	0.15
Final Test (hrs)	0.15	0.1	0.15	0.20	0.25
Pallet Loading (hrs)	0.5	0.15	0.75	0.50	3.00
Marking and Misc. (hrs)	0.35	0.08	0.35	0.35	0.75

5.4.5.1 Variable Core Costs

- 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 cost (in dollars) for these activities is calculated by the weight of the core (in pounds) multiplied by a constant, which varies with the lamination thickness of the core steel ([labor costs] = [core weight]*[constant]). For RU1, RU2, and RU4, on 0.012 inch (0.30 mm) steel the constant is 0.08, 0.011 inch (0.27 mm) steel is 0.09, M4 is 0.10, 0.009 inch (0.23 mm) steel are 0.125, and 0.007 inch (0.18 mm) is 0.16. For RU3 and RU5, the distribution transformers are larger so some costs are amortized over more steel and the labor cost per pound of core steel are lesser, on 0.012 inch (0.30 mm) steel the constant is 0.05, 0.011 inch (0.27 mm) steel is 0.06, 0.009 inch (0.23 mm) steel is 0.07, 0.009 inch (0.23 mm) steel are 0.09, and 0.007 inch (0.18 mm) is 0.11. For the prefabricated core —amorphous material—DOE set the labor for cutting, forming, and annealing to zero.

- 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. DOE calculated the labor cost (in dollars) for these activities based on the weight of the core (in pounds) multiplied by a constant, which varies by representative unit ([labor costs] = [core weight]*[constant]). For RU1, RU2 and RU4 the constant is 0.06. For RU3 and RU5 the distribution transformers are larger so some costs are amortized over more steel and the labor cost per pound of core steel are lesser, and the constant is 0.04. There are also an additional 10 hour of labor costs ([labor costs] = [core weight]*[constant] + [10 hours]*[labor cost per hour]) for RU5 amorphous core designs associated with the added difficulty of working with such a large amorphous core. All other representative units and non-amorphous designs do not include this additional labor costs.

5.4.6 Dry-Type Labor Hours

Likewise, there are several labor steps involved in manufacturing a dry-type transformer. DOE 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 prepared based on data and feedback from manufacturers in negotiations. These steps are described below.

5.4.6.1 Fixed Labor Costs (hours)

- 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.

- 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.

Table 5.4.8 LVDT Labor Hours

Labor Activity	RU6 hrs	RU7 hrs	RU8 hrs
Primary Winding (hrs/turn)	0.001	0.0015	0.01
Secondary Winding (hrs/turn)	0.01	0.011	0.04
Lead Dressing (hrs)	0.15	0.25	0.5
Enclosure Manufacturing (hrs)	0.75	1.5	3.0
Inspection (hrs)	0.05	0.05	0.1
Preliminary Test (hrs)	0.05	0.05	0.1
Final Test (hrs)	0.1	0.1	0.15
Packing (hrs)	0.2	0.2	1
Marking and Misc. (hrs)	0.2	0.2	0.6

- 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, core size, and whether the core is grain-oriented or non-oriented. Thus, the labor for core stacking varies with the efficiency of the transformer. ([labor costs] = [core weight]*[constant]*[labor rate])

- 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. Large amorphous core have additional labor hours associated with the added difficulty of working with such a large amorphous core.

- 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. DOE calculated the labor cost (in dollars) for these activities based on the weight of the core (in pounds) multiplied by a constant, which varies by representative unit ([labor costs] = [core weight]*[constant]). For dry-type grain-oriented distributed gap wound distribution transformers this constant was 0.06.

- Cutting, Forming, and Annealing (Only for distributed gap wound cores) – 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 cost (in dollars) for these activities is calculated by the weight of the core (in pounds) multiplied by a constant, which varies with the lamination thickness of the core steel ([labor costs] = [core weight]*[constant]). For RU6, on 0.012 inch (0.30 mm) steel the constant is 0.08, 0.011 inch (0.27 mm) steel is 0.09, M4 is 0.10, 0.009 inch (0.23 mm) steel are 0.125, and 0.007 inch (0.18 mm) is 0.16. For the prefabricated core — amorphous material—DOE set the labor for cutting, forming, and annealing to zero.

Table 5.4.9 LVDT Core Labor Hours

Labor Activity	RU6 hrs	RU7 hrs	RU8 hrs
Assembly	0.35	1	2.5
BL/FM Core Stacking	0.25	0.35	0.38
SLM Core Stacking	0.20	0.28	0.304

DOE received manufacturer feedback that using a similar method for calculating labor hours underestimated the labor required for medium voltage dry-type distribution transformer. One manufacturer provided DOE with a formula for calculating labor hours. For CRGO cores, DOE used Eq. 5.7. For amorphous cores, DOE calculated the required labor hours using Eq. 5.8. The manufacturer provided DOE with the appropriate core factors and base labor hours for each representative unit. These factors are presented in Table 5.4.10.

$$[Hours] = [CRGO\ Core\ Factor] * \frac{[Core\ Weight\ (lbs)]}{[Core\ thickness\ (inches)]} + [Base\ CRGO\ Labor\ Hrs]$$

Eq. 5.7

$$[Hours] = [AM\ Core\ Factor] * [Core\ Weight] + [Base\ AM\ Labor\ Hrs]$$

Eq. 5.8

Table 5.4.10 MVDT Labor Hour Calculation Variables from Manufacturer Feedback

Labor Activity	RU9 hrs	RU10 hrs	RU11 hrs	RU12 hrs	RU13 hrs	RU14 hrs
CRGO Core Factor	0.00005044	0.00004604	0.00005367	0.00004512	0.00006561	0.00002636
Base CRGO Labor Hours	53.12	76.17	56.935	80.42	60.63	97.16
AM Core Factor	-0.0027	0.003235	0.0038	0.0029	0.0042	0.001777
Base AM Labor Hours	33.76	75.855	55.77	85.991	61.406	98.25567

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, 2013 standards 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

To develop efficiency levels for each representative unit, DOE first found the range of efficiencies possible for each representative unit, ranging from the baseline to max-tech, and selected ELs based on a certain percentage of reduction in losses for each representative unit.

5.5.2 Efficiency Levels Selected

Table 5.5.1 presents the efficiency levels (ELs) identified for each representative unit in the engineering analysis. Table 5.5.2 presents the incremental MSP for each of the least-costly design options at each efficiency level using 2020 prices.

Table 5.5.1 Summary of Baselines and Efficiency Levels for Distribution Transformer Representative Units

RU	Specification	Baseline Eff. [%]	EL1 Eff. [%]	EL2 Eff. [%]	EL3 Eff. [%]	EL4 Eff. [%]	EL5 Eff. [%]
1	50 kVA, 65°C, 1-phase, 60Hz, 14400V primary, 240/120V secondary, rect. tank	99.11	99.13	99.15	99.20	99.29	99.47
2	25 kVA, 65°C, 1-phase, 60Hz, 14400V primary, 120/240V secondary, round tank	98.95	98.98	99.00	99.06	99.16	99.37
3	500 kVA, 65°C, 1-phase, 60Hz, 14400V primary, 277V secondary	99.49	99.50	99.52	99.54	99.59	99.69
4	150 kVA, 65°C, 3-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary	99.16	99.18	99.20	99.24	99.33	99.50
5	1500 kVA, 65°C, 3-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary	99.48	99.49	99.51	99.53	99.58	99.69
6	25 kVA, 150°C, 1-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL	98.00	98.20	98.40	98.60	98.80	99.00
7	75 kVA, 150°C, 3-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL	98.60	98.74	98.88	99.02	99.16	99.30
8	300 kVA, 150°C, 3-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL	99.02	99.12	99.22	99.31	99.41	99.51
9	300 kVA, 150°C, 3-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL	98.93	98.98	99.04	99.20	99.25	99.36
10	1500 kVA, 150°C, 3-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL	99.37	99.40	99.43	99.53	99.56	99.62
11	300 kVA, 150°C, 3-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	98.81	98.87	98.93	99.11	99.17	99.29
12	1500 kVA, 150°C, 3-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	99.30	99.34	99.37	99.48	99.51	99.58
13	300kVA, 150˚C, 3-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	98.69	98.76	98.82	99.02	99.08	99.15
14	2000kVA, 150˚C, 3-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	99.28	99.32	99.35	99.46	99.50	99.53

Table 5.5.2 Incremental Manufacturer Selling Prices Over the Baseline for Distribution Transformer Representative Units

RU	Specification	Baseline	EL1	EL2	EL3	EL4	EL5
		2020$	2020 $	2020 $	2020$	2020$	2020$
1	50 kVA, 65°C, 1-phase, 60Hz, 14400V primary, 240/120V secondary, rect. tank	0	68	96	254	362	1003
2	25 kVA, 65°C, 1-phase, 60Hz, 14400V primary, 120/240V secondary, round tank	0	47	79	127	202	539
3	500 kVA, 65°C, 1-phase, 60Hz, 14400V primary, 277V secondary	0	152	591	868	1562	3624
4	150 kVA, 65°C, 3-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary	0	153	287	327	327	1125
5	1500 kVA, 65°C, 3-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary	0	1022	1147	1706	3550	14347
6	25 kVA, 150°C, 1-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL	0	0	27	66	215	380
7	75 kVA, 150°C, 3-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL	0	62	330	638	772	1047
8	300 kVA, 150°C, 3-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL	0	312	1312	2150	2254	3198
9	300 kVA, 150°C, 3-phase, 60Hz, 4160V Delta primary, 480Y/277V secondary, 45kV BIL	0	28	117	957	1268	2194
10	1500 kVA, 150°C, 3-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL	0	721	1890	6892	8683	12501
11	300 kVA, 150°C, 3-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	0	566	1073	2690	3169	4163
12	1500 kVA, 150°C, 3-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL	0	1819	2938	11453	12582	17950
13	300kVA, 150˚C, 3-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	0	252	690	3126	4685	5157
14	2000kVA, 150˚C, 3-phase, 60Hz, 24940V primary, 480Y/277V secondary, 125kV BIL	0	2278	3926	14014	16250	21294

5.5.3 Bus Lead and Bus Loss Correction

DOE received comment during the April 2013 standards rulemaking process 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 bus and lead losses, which can force a unit to employ larger, more efficient cores and coils to overcome the added loss.

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 representative units. For each representative unit, 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. DOE has retained this adjustment for all medium-voltage dry-type distribution transformers in this rulemaking.

5.6 RESULTS OF THE ANALYSIS ON EACH REPRESENTATIVE UNIT

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 fourteen (14) representative units. 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 Design 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 2017 steel price scenario.

Figure 5.6.1 presents a plot of the manufacturer selling price and efficiency levels for the full database of designs for the representative unit from RU1, a 50 kVA single-phase, liquid-immersed, pad-mounted distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about these scatter plots:

- The current standard efficiency level of 99.11 percent is most cost-effectively met by designs using 23pdr075 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.23 percent and can reach efficiencies of 99.54 percent.

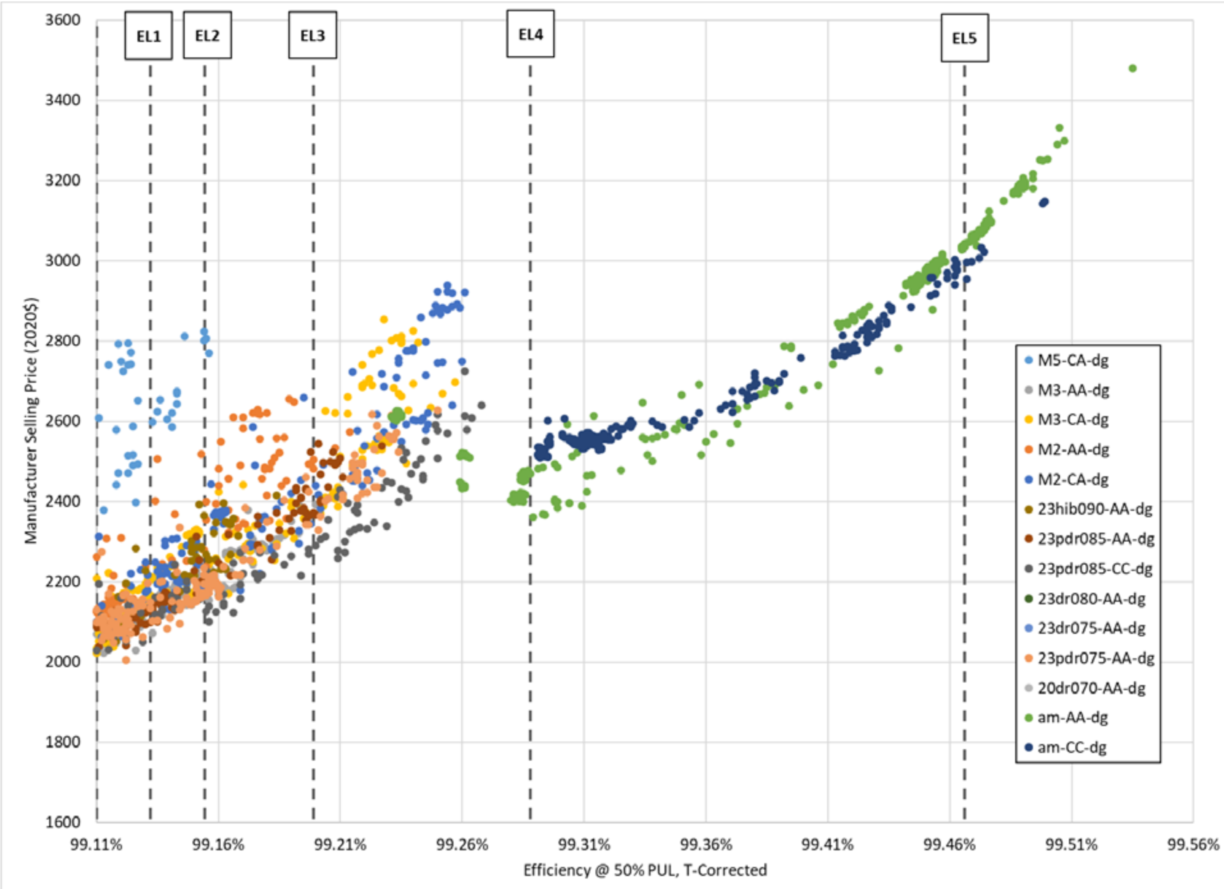


Figure 5.6.1 Engineering Analysis Results, RU1, 2020

Figure 5.6.2 presents a plot of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU2, a 25 kVA single-phase, liquid-immersed, pole-mounted distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observation can be made about this scatter plot:

- The current standard efficiency level of 98.95 percent is most cost-effectively met by designs using 23pdr075 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.02 percent and can reach efficiencies of 99.48 percent.

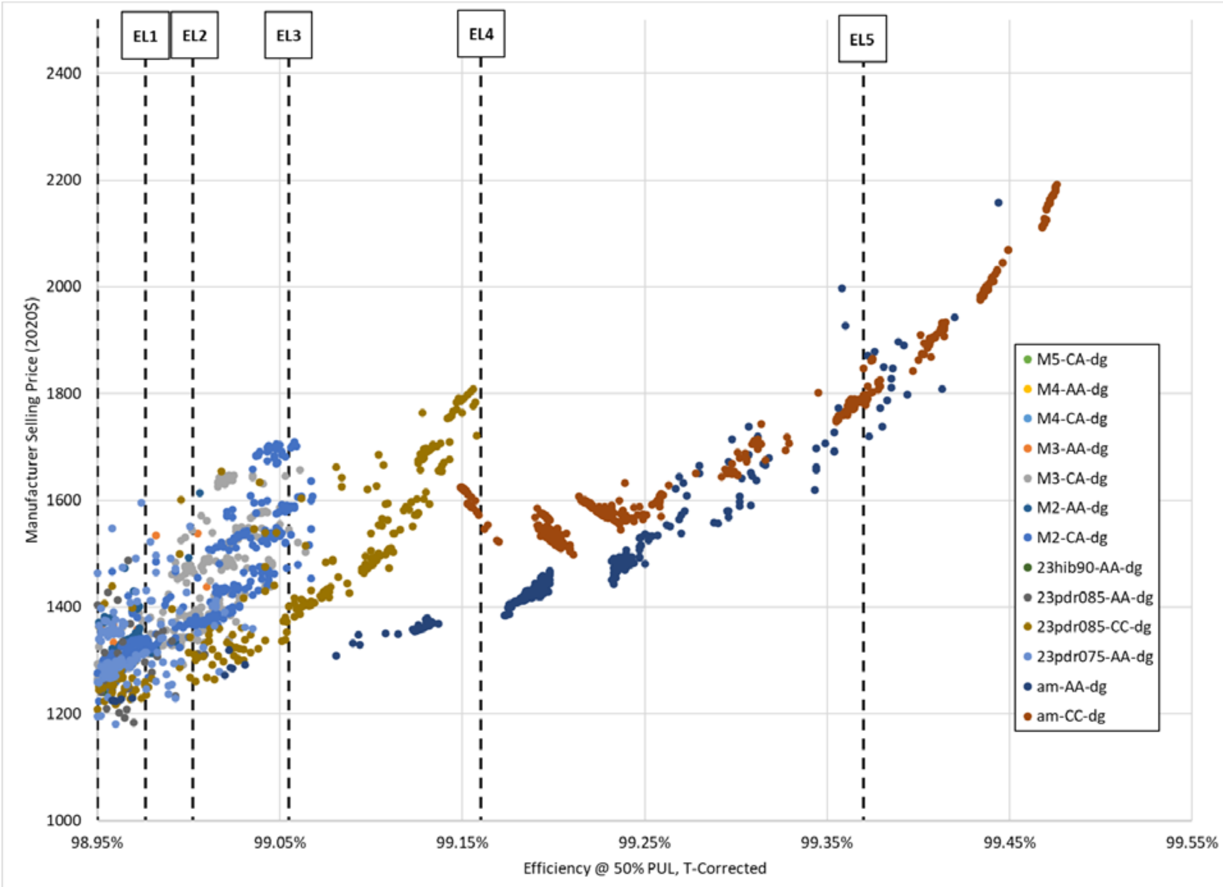


Figure 5.6.2 Engineering Analysis Results, RU2, 2020

Figure 5.6.3 presents a plot of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU3, a 500 kVA single-phase, liquid-immersed distribution transformer with radiators. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.49 percent is most cost-effectively met by designs using 23pdr085 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.52 percent and can reach efficiencies of 99.74 percent.

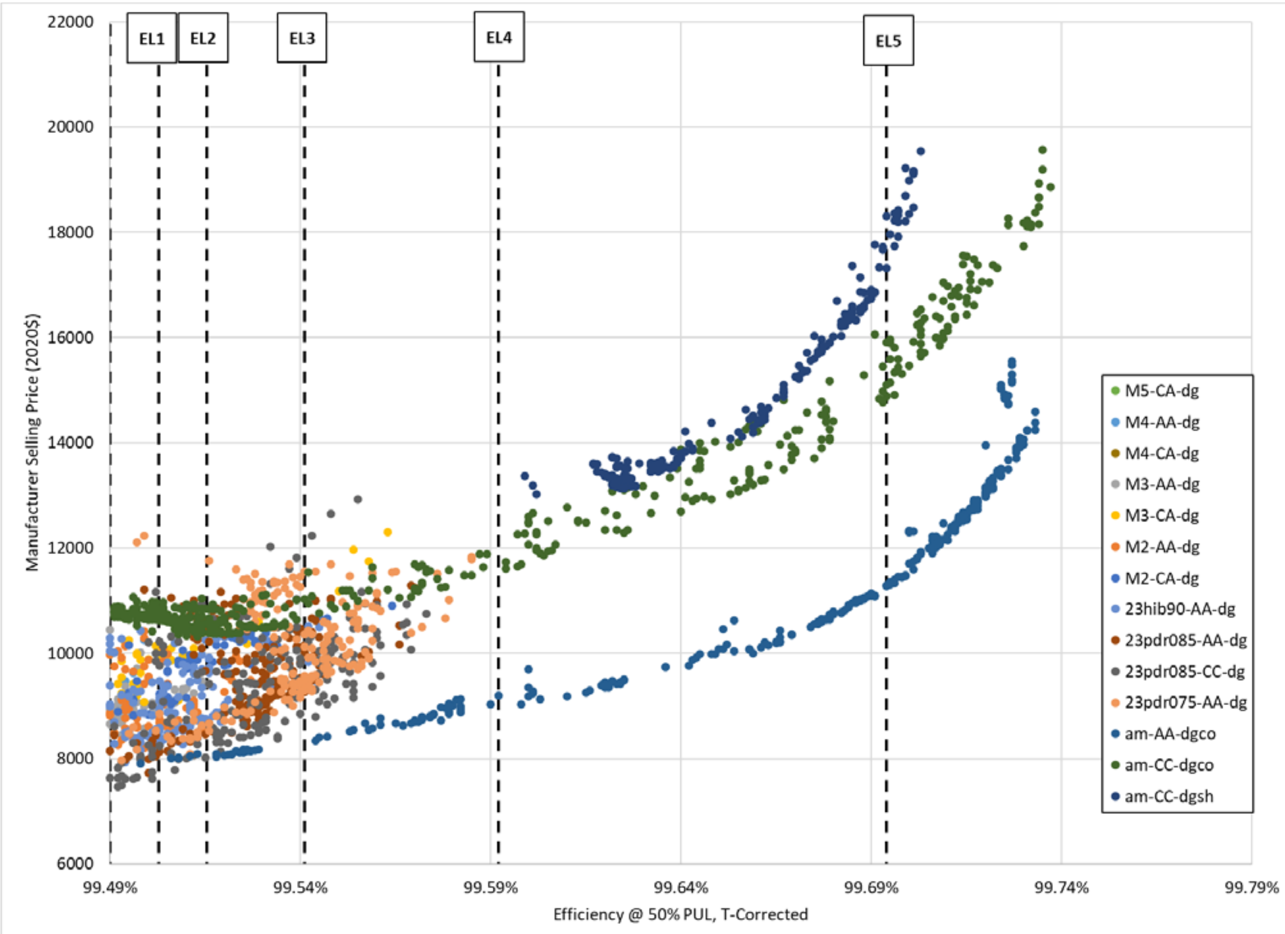


Figure 5.6.3 Engineering Analysis Results, RU3, 2020

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 RU4, a 150 kVA three-phase, liquid-immersed distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.16 percent is most cost-effectively met by designs using 23pdr085 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.22 percent and can reach efficiencies of 99.61 percent.

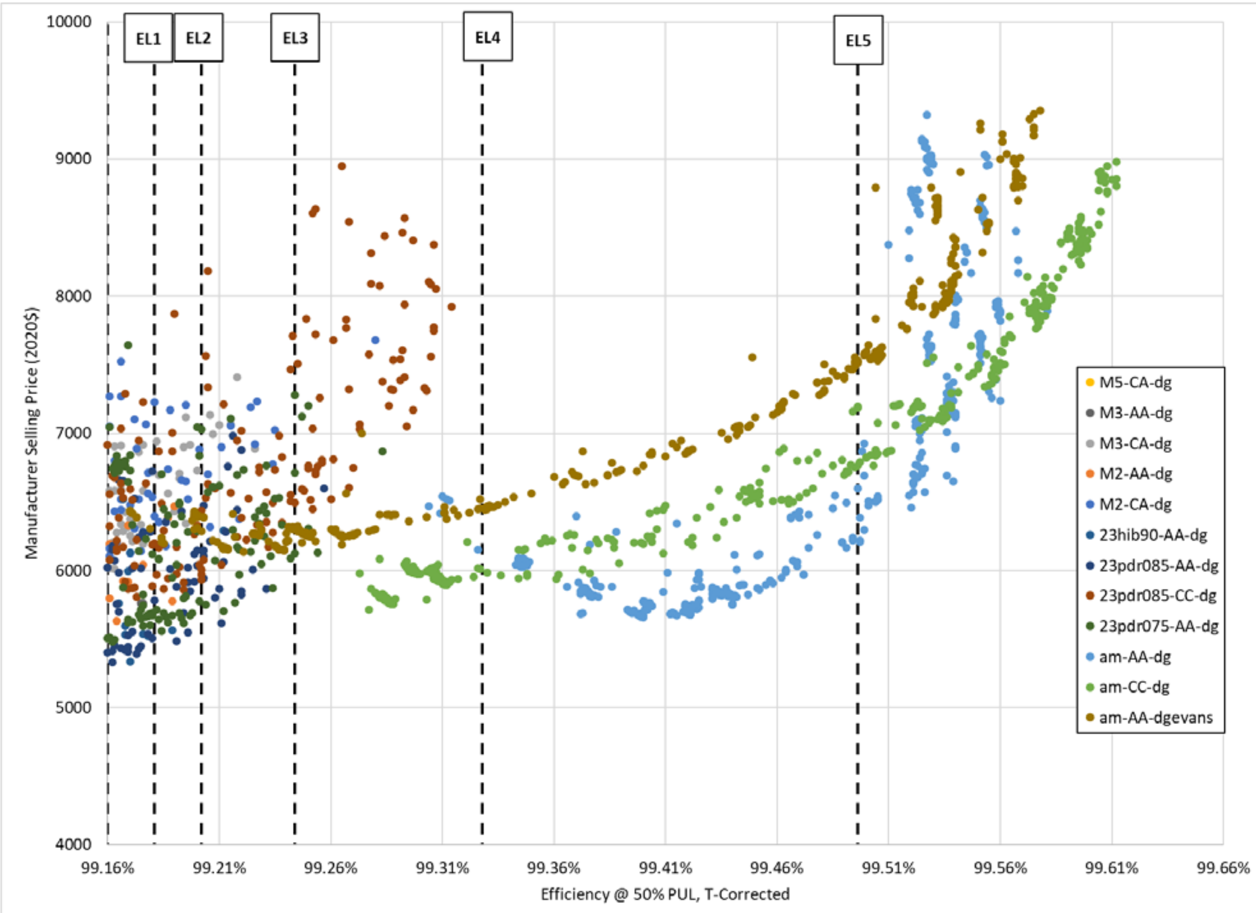


Figure 5.6.4 Engineering Analysis Results, RU4, 2020

Figure 5.6.5 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU5, a 1500 kVA three-phase, liquid-immersed distribution transformer. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.48 percent is most cost-effectively met by designs using 23pdr085 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.49 percent and can reach efficiencies of 99.71 percent.

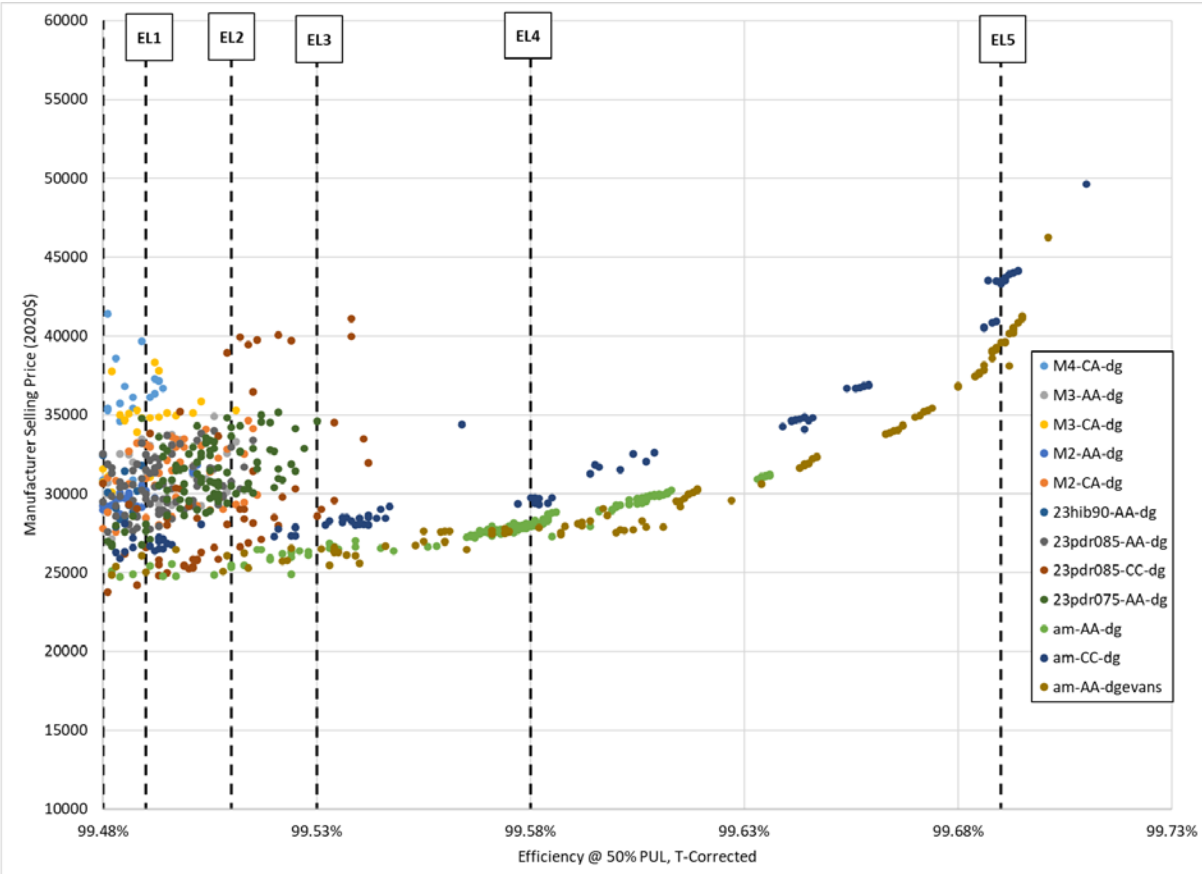


Figure 5.6.5 Engineering Analysis Results, RU5, 2020

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 RU6, a 25kVA single-phase, low-voltage, dry-type distribution transformer. The efficiency levels shown in this plot represent transformers at 35 percent of per-unit 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 M3 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 98.89 percent and can reach efficiencies of 99.45 percent.

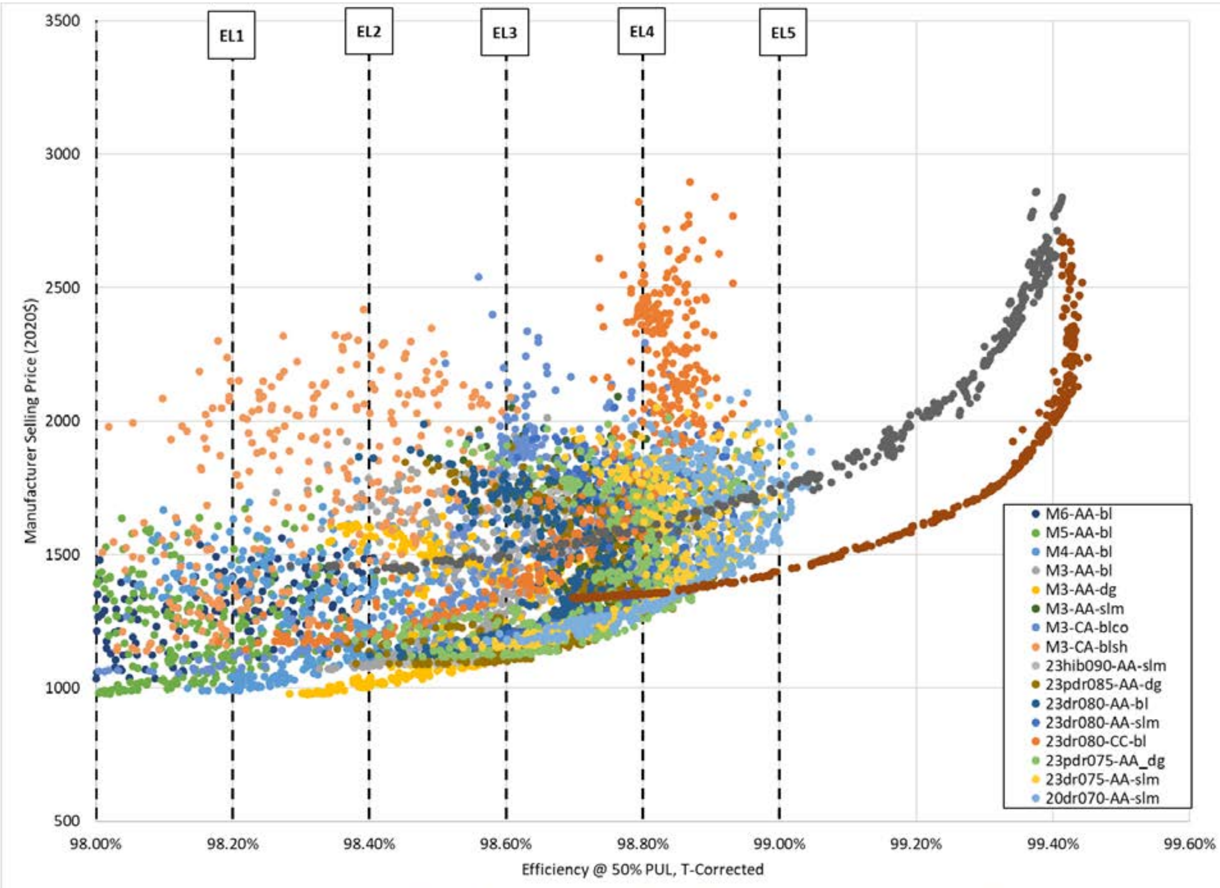


Figure 5.6.6 Engineering Analysis Results, RU6, 2020

Figure 5.6.7 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU7, a 75 kVA three-phase, low-voltage, dry-type distribution transformer. The efficiency levels shown in this plot represent transformers at 35 percent of per-unit 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 23pdr085 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.00 percent and can reach efficiencies of 99.45 percent.

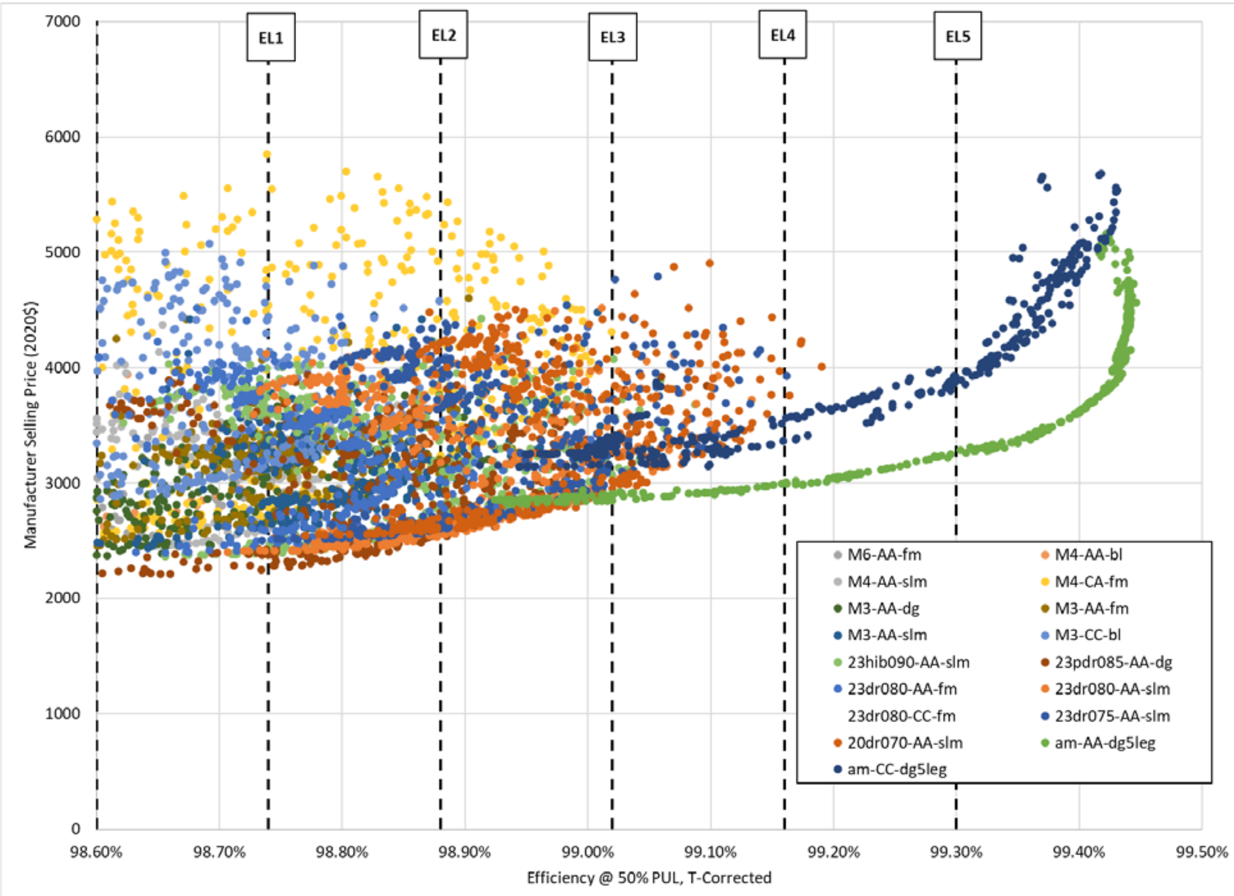


Figure 5.6.7 Engineering Analysis Results, RU7, 2020

Figure 5.6.8 present a plot of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU8, a 300 kVA three-phase, low-voltage, dry-type distribution transformer. The efficiency levels shown in this plot represent transformers at 35 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.02 percent is most cost-effectively met by designs using M3 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.32 percent and can reach efficiencies of 99.59 percent.

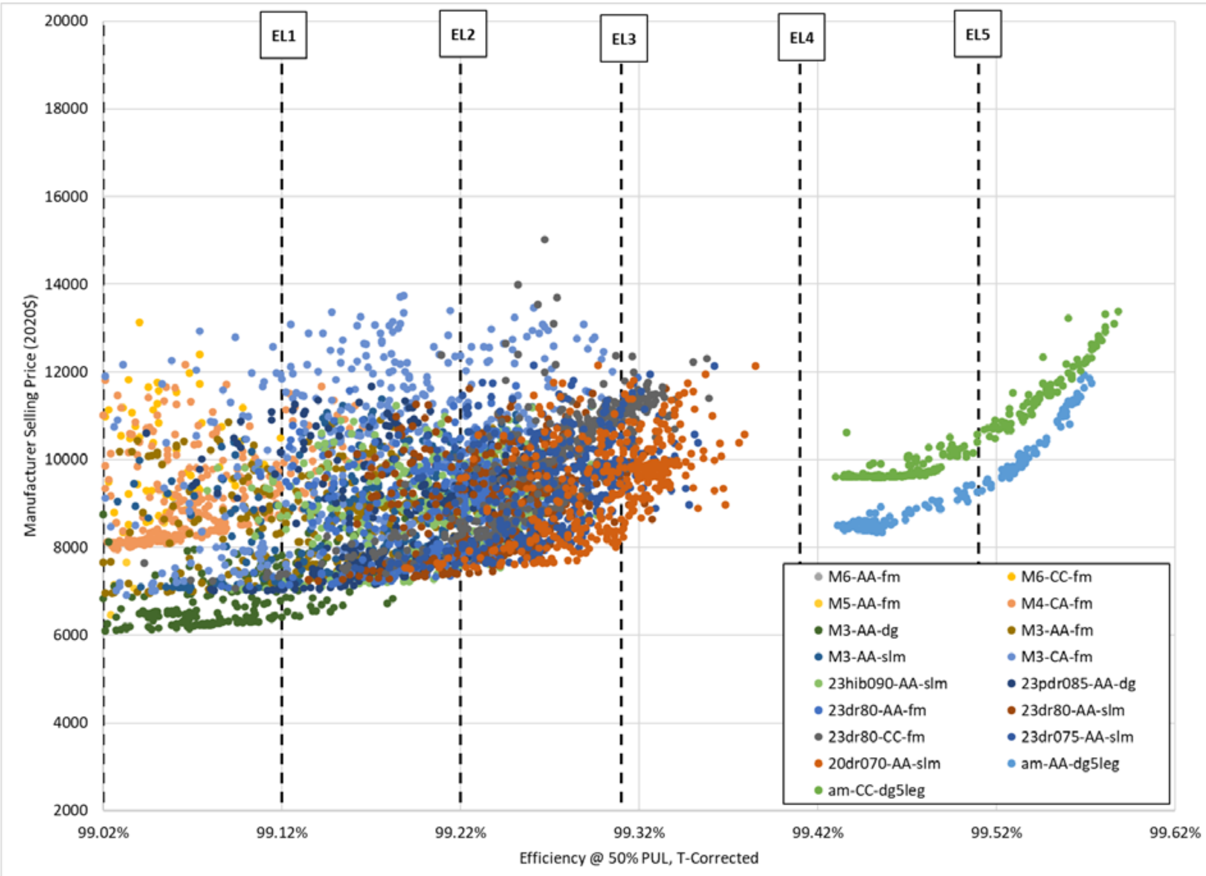


Figure 5.6.8 Engineering Analysis Results, RU8, 2020

Figure 5.6.9 presents a plot of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU9, a 300 kVA three-phase, medium-voltage, dry-type transformer with a 45kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.93 percent is most cost-effectively met by designs using M4 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.19 percent and can reach efficiencies of 99.57 percent.

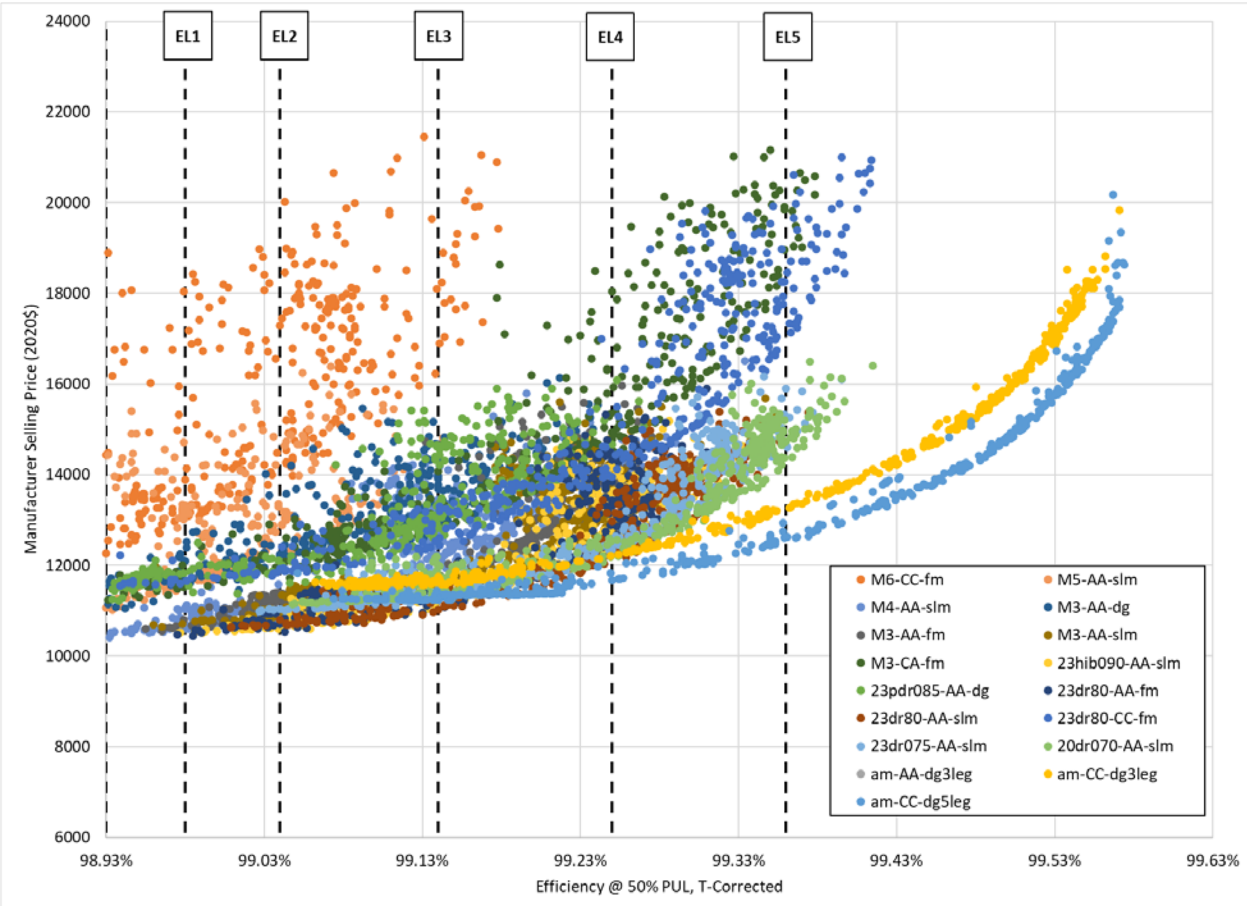


Figure 5.6.9 Engineering Analysis Results, RU9, 2020

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 RU10, a 1500 kVA three-phase, medium-voltage, dry-type transformer with a 45 kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.37 percent is most cost-effectively met by designs using 23hib090 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.49 percent and can reach efficiencies of 99.65 percent.

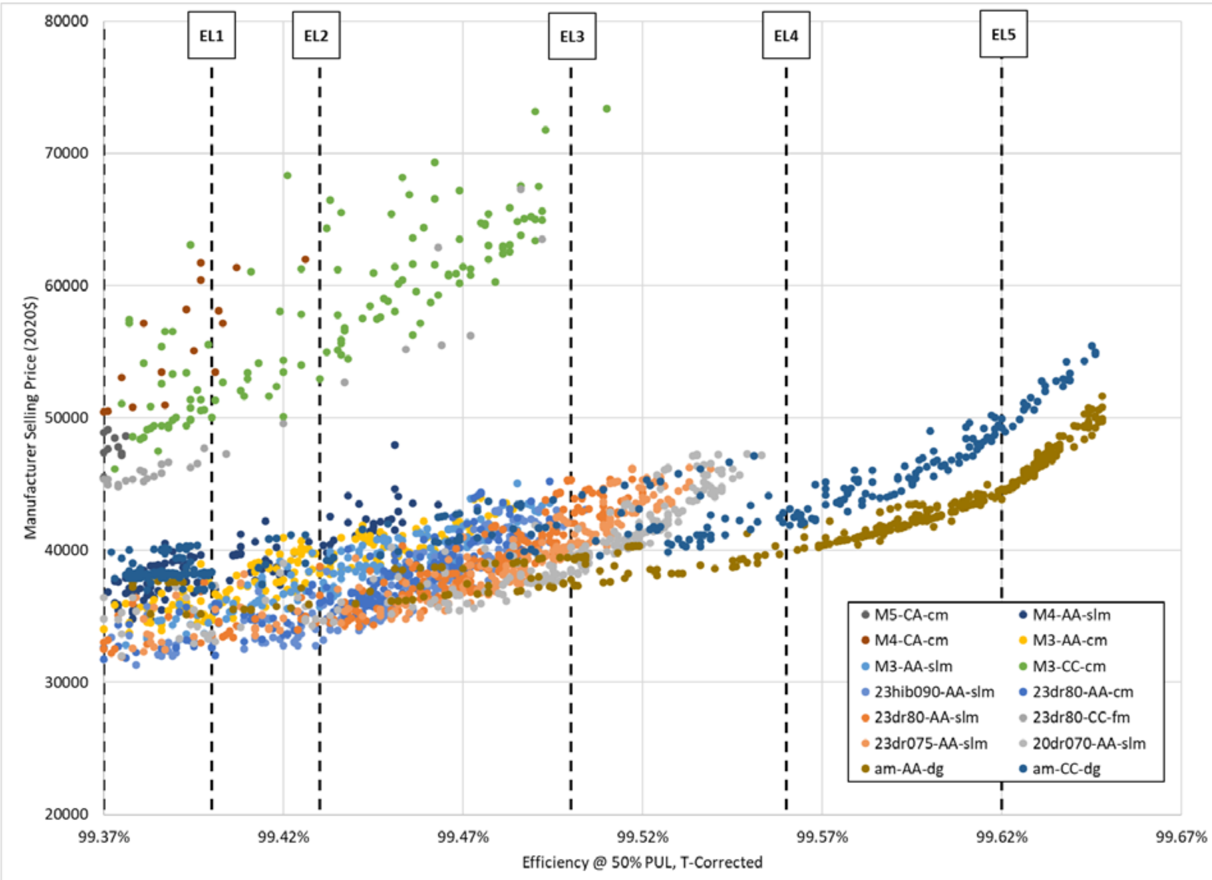


Figure 5.6.10 Engineering Analysis Results, RU10, 2020

Figure 5.6.11 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU11, a 300 kVA three-phase, medium-voltage, dry-type transformer with a 95 kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.81 percent is most cost-effectively met by designs using 23pdr085 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.06 percent and can reach efficiencies of 99.51 percent.

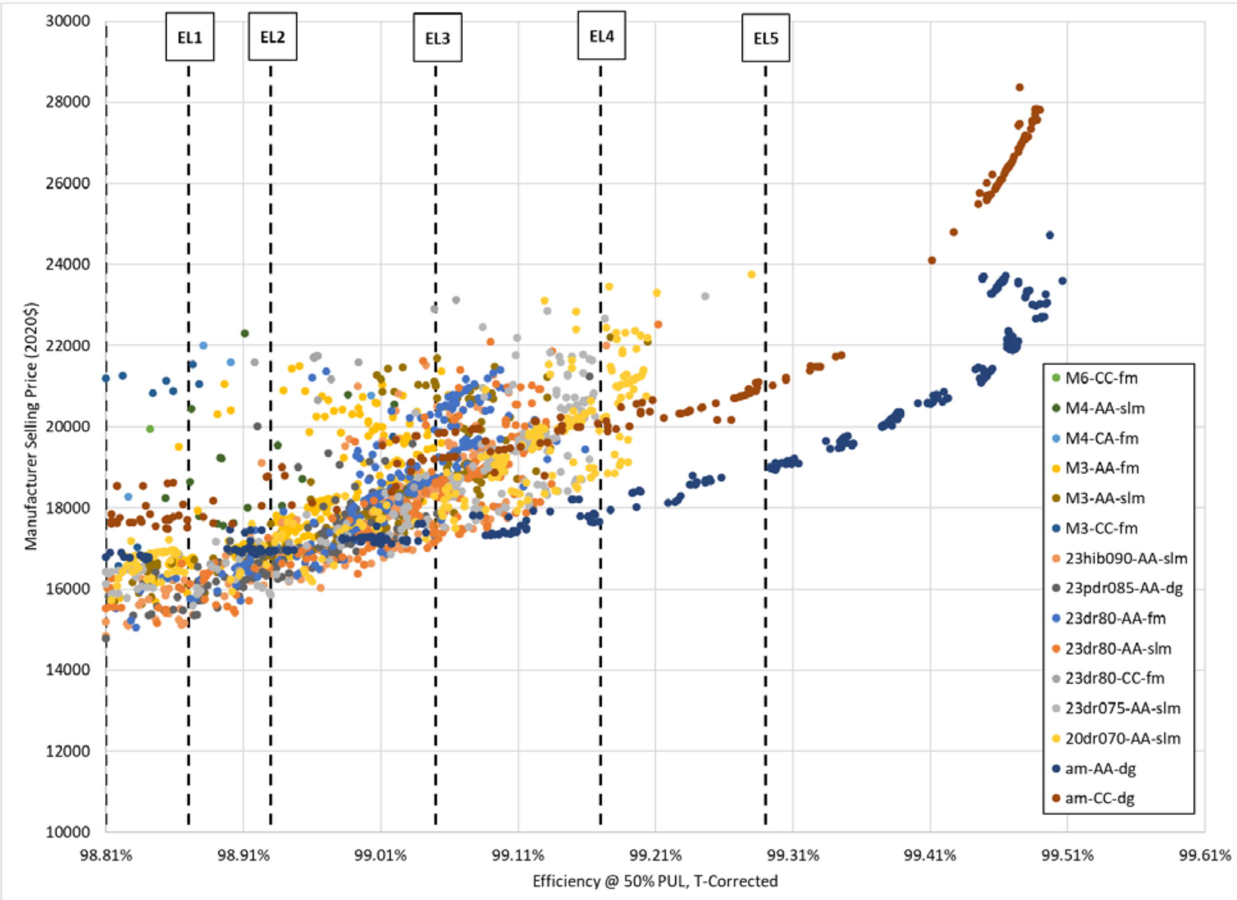


Figure 5.6.11 Engineering Analysis Results, RU11, 2020

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 RU12, 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 per-unit load. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.30 percent is most cost-effectively met by designs using 23dr80 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.46 percent and can reach efficiencies of 99.64 percent.

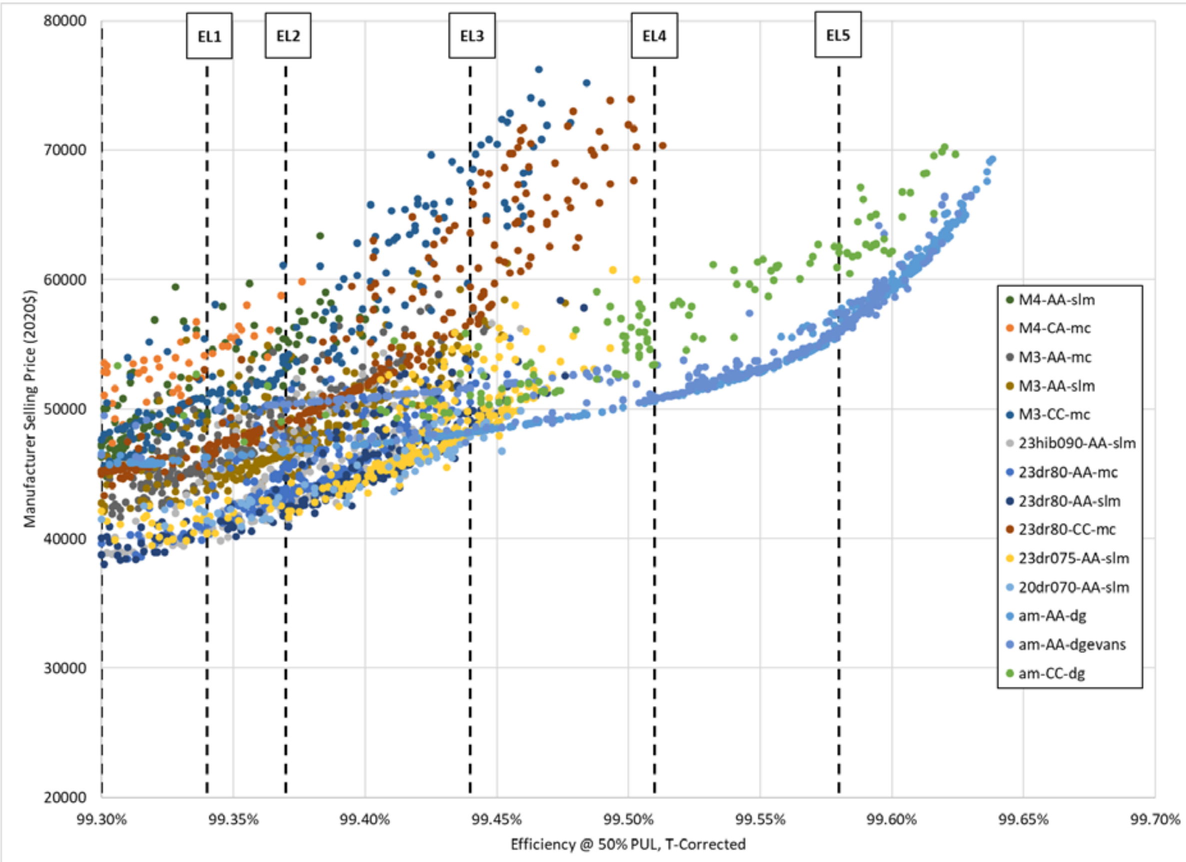


Figure 5.6.12 Engineering Analysis Results, RU12, 2020

Figure 5.6.13 present plots of the manufacturer sales prices and efficiency levels for the full database of designs for the representative unit from RU13, a 300 kVA three-phase, medium-voltage, dry-type transformer with a 125 kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 98.69 percent is most cost-effectively met by designs using 23hib090 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.07 percent and can reach efficiencies of 99.47 percent.

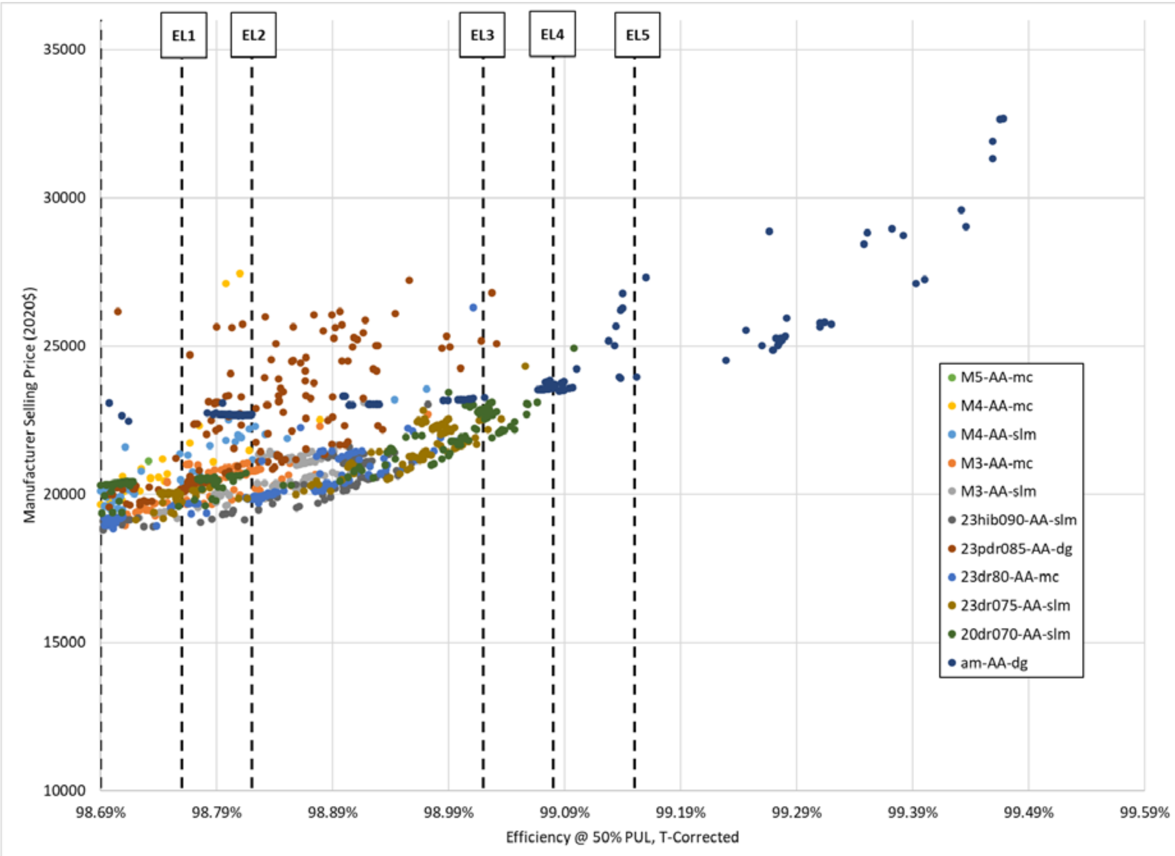


Figure 5.6.13 Engineering Analysis Results, RU13, 2020

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 RU14, a 2000 kVA three-phase, medium-voltage, dry-type transformer with a 125 kV BIL. The efficiency levels shown in this plot represent transformers at 50 percent of per-unit load and are corrected for temperature. The following observations can be made about this scatter plot:

- The current standard efficiency level of 99.28 percent is most cost-effectively met by designs using M3 core steel.
- The amorphous metal core is the most cost-effective design for any efficiency level above 99.44 percent and can reach efficiencies of 99.55 percent.

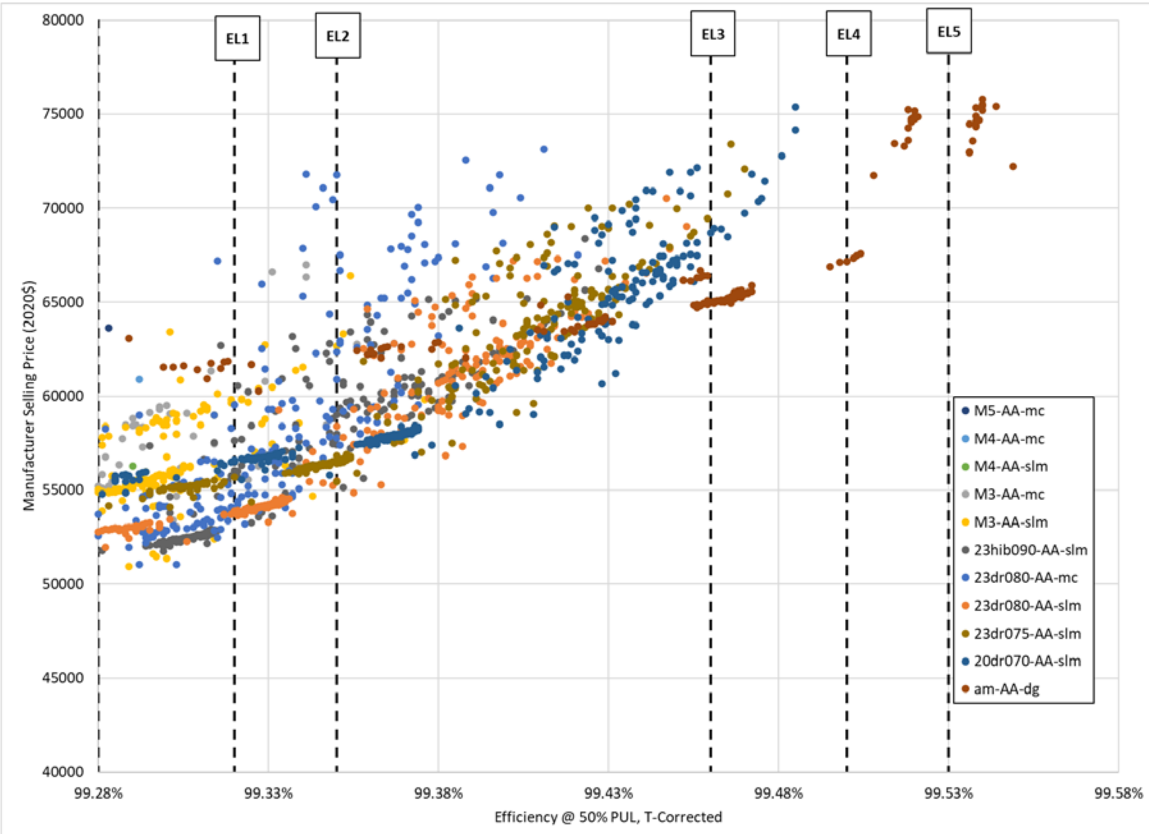


Figure 5.6.14 Engineering Analysis Results, RU14, 2020

5.7 PROCUREMENT AND CERTIFICATION DATA COMPARISON

5.7.1 Background

5.7.1.1 Liquid-Immersed

Some electrical power utilities publish data related to procurement of distribution transformers. Commonly, the data is made available as part of a public procurement process in which a municipal electrical utility solicits bids for distribution transformers (among other electrical equipment) it intends to purchase from sellers of distribution transformers, some of whom are also the manufacturers.

Along with the solicitation for bids, the utilities typically include criteria for award of contract. For example, the utility may award the contract to the bidder offering the lowest purchase price for designs meeting a certain specification. Alternatively, it may award the contract to the bidder offering the lowest total owning cost when calculated using utility-provided loss values. Alternatively, the utility may combine the two approaches and select the unit that has the lowest purchase price among those with total owning costs not greater than 103% of the lowest total owning cost design. Other considerations may apply. For example, a request for quotation may specify that amorphous material either must be offered or will not be considered.

The published data related to this procurement process many include, at least, any of the following, which will be collectively referred to as "bid data":

- Request for Quotation
- Design Specification for Distribution Transformers Sought
- Summary of Bids Received
- Individual Bid Responses

For the preliminary analysis, DOE collected some publicly available bid data for a variety of distribution transformers using a combination of internet research and direct requests to the issuing agency. Not all direct requests were responded to or resulted in provision of the data requested. Not all responses received contained complete or useful data. The data received was limited to liquid-immersed distribution transformers. DOE did not locate equivalent procurement data for dry-type transformers, which are less frequently purchased by electrical utilities.

The objective of collecting bid data was to assess the degree to which a relationship between selling price and efficiency could be observed. Results are presented in this section.

5.7.1.1 Dry-Type

As stated in section 5.7.1.1, the bid data obtained was limited to liquid-immersed distribution transformers. DOE did not locate equivalent procurement data for dry-type transformers, which are less frequently purchased by electrical utilities. In place of bid data, for dry-type distribution transformers this preliminary analysis compares engineering analysis results with efficiency values certified to both DOE and the California Energy Commission ("CEC"). This "certification data" contains some efficiency values but not anything relate to manufacturer selling price. As a result, the comparison with engineering analysis results is possible only along the efficiency axis.

The certification data does, at least, illustrate the range of efficiency values certified to DOE. This can be understood as a lower bound of the range of efficiencies likely deemed cost-effective for at least some consumers to purchase, as increased efficiency above standards is voluntary. The efficiency range of certification data cannot be understood as the upper limit of what is either technologically feasible or cost-justified. More efficient designs may be buildable but yet unsold. Or, as it is permitted to represented efficiency values lower than the design's actual, measured efficiency, the true efficiency may be higher. DOE notes that the certified data presented represents models that fall within the EC BIL range, are of identical kVA size, and identical phase (single vs three phase) but do not necessarily have identical primary and secondary windings as the RUs they are being compared to.

5.7.2 Factors Confounding Comparison

Several factors complicate the ability to draw firm conclusions from such bid data in aggregate form. The bid data includes different designs for different customers in different time periods (in general the data is from the 2010's), all of which may affect manufacturer selling price for reasons unrelated to the efficiency of the distribution transformer and which may thereby obscure the effect on manufacturer selling price of efficiency alone.

Confounding factors potentially obscuring effect of efficiency on MSP:

- Differences in design specification.
    - Voltage
    - Connection
    - Impedance
    - BIL
    - Tank material
    - Weight or volume limits
- Inclusion in selling price of taxes.
- Inclusion in selling price of delivery/freight charges.
- The effect of changes in costs of materials and labor used to construct distribution transformers.
- Order size.
- Effect of energy conservation standards in and after 2016.

For this preliminary analysis, DOE has filtered bid data to compare distribution transformers of the same phase (single or three phase), kVA size, and mount/shape (pole vs pad), with each of its liquid-immersed representative units (RU1, RU2, RU3, RU4, and RU5) modeled data. In filtering results for comparison, DOE did not attempt to control for the combined effect of the other factors in a way that would allow representation of bid data as energy analysis per se. Trying to find an exact match of the procured data and representative unit resulted in thin comparable data. As a result, the bid data includes a wide range of prices and efficiencies for a given representative unit. But no single point can be viewed as an exact match or an exact comparison. Further, DOE did not use this data in any downstream analyses. It is provided for review in sections 5.7.4, 5.7.5, and 5.7.6 in both raw form and with several corrections intended to render more direct comparison of the incremental costs associated with increasing efficiency.

5.7.3 Corrections to Bid Data

The specific corrections performed to raw bid data are: (1) inflation, (2) load loss, (3) price offset, and (4) outlier removal.

The inflation correction is intended to correct for the fact that purchases in different years are made using US Dollars of differing value. For the preliminary analysis, DOE adjusted prices to the 2020 year using the US Gross Domestic Product Implicit Price Deflator obtained from US Federal Reserve published economic data.[3]

For dry-type transformers, inflation adjustment was not performed because no price data was obtained.

The load loss correction is intended to bring load loss values presented in bid data, nearly always expressed at 100% PUL and at the rated temperature rise, into comparability with the data used in DOE's engineering analysis, which analyzes performance at 50% PUL and the reference temperature prescribed in Appendix A of to Subpart B of 10 CFR 430. Because resistive loss (the dominant component of load loss) grows quadratically with PUL, scaling load loss from 100% to 50% would (absent other factors) tend to reduce load loss to .5^2, or 25%, of its full-load values. Additionally, load loss is affected by operating temperature, which always declines with reduced PUL by some amount that depends on the specifics of the transformer design. By analyzing a set of liquid-immersed transformer designs, DOE estimated the magnitude of the temperature effect to be a further 2.5% of the full-load values. In sum, the two effects combine for a load loss adjustment of bid data values to (.5^2-2.5%), or 22.5%, of full-load values. DOE adjusted all liquid immersed bid-data load-loss values to a fixed 22.5% of their published full-load values.

For dry-type transformers, adjustment was not necessary as performance data came from certification databases in which efficiency is already represented in accordance with test procedure requirements.

The price offset correction shifts the entire set of bid data for a given RU by a fixed amount to align the baseline price of the bid dataset with that of DOE's engineering analysis dataset. The objective of this correction is to focus comparison on incremental MSP change with efficiency, relative to the baseline MSP. Incremental MSP, rather than baseline, drives economic results (*e.g.,* life-cycle cost and payback period) as economics are calculated for cost (and energy consumption) in excess of the baseline values. To the extent that incremental MSP varies between engineering analysis data and bid data, normalizing each set to a common starting point makes such variation easier to observe.

For dry-type transformers, no price offset was performed as no price data was obtained.

The final correction to each RU dataset was removal of apparent outliers. Identification of outliers was done manually, and only for points that appeared significantly far enough below the next cheapest units for a given price range to raise concern of an error. Outliers are retained on the plots and colored in green but ignored in the price offset calculations for the purposes of aligning the datasets.

5.7.4 Liquid-Immersed Procured Data Plots

The data in this section is organized by representative unit, for which bid data is overlaid atop engineering analysis data. The data is informational; and no conclusions are presented. For each liquid-immersed representative unit, the first plot contains the bid data unmodified and the second plot contains bid data with corrections (described in section 5.7.3) performed with the objective of enabling better comparison of the incremental cost of efficiency improvement.

5.7.4.1 RU1

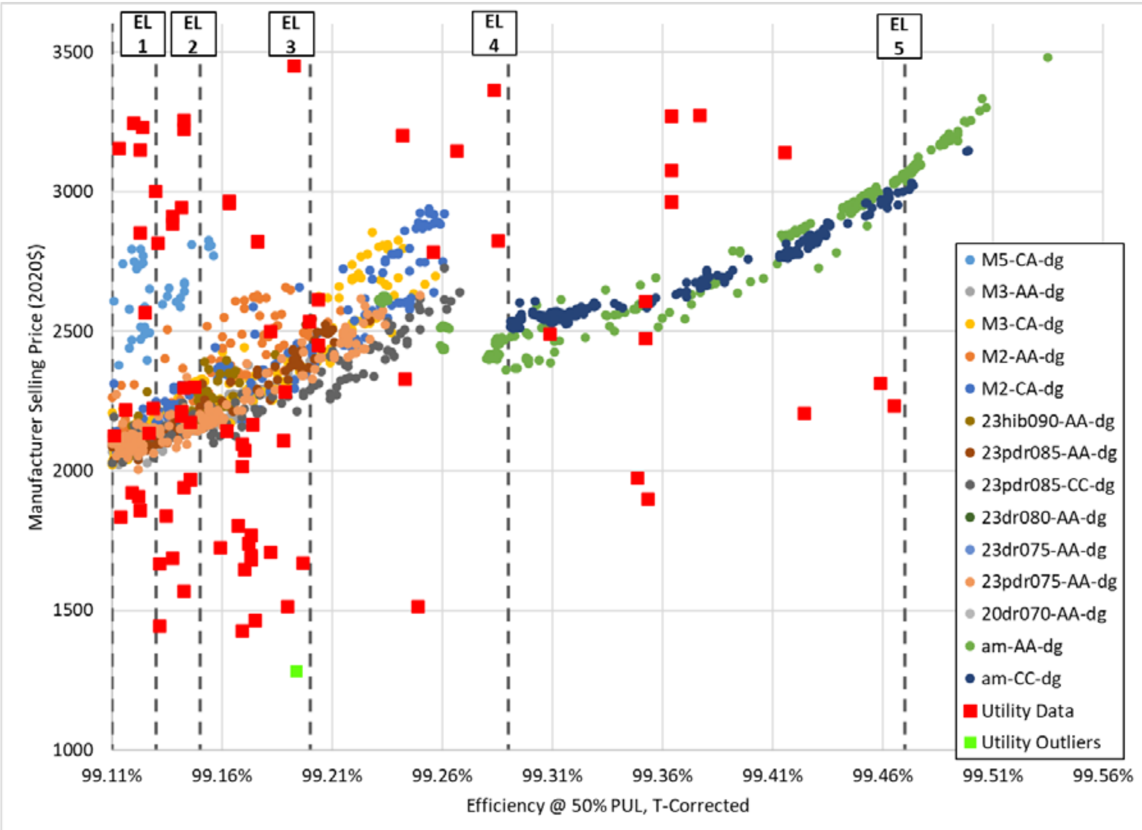


Figure 5.7.1 RU1 – Raw Data

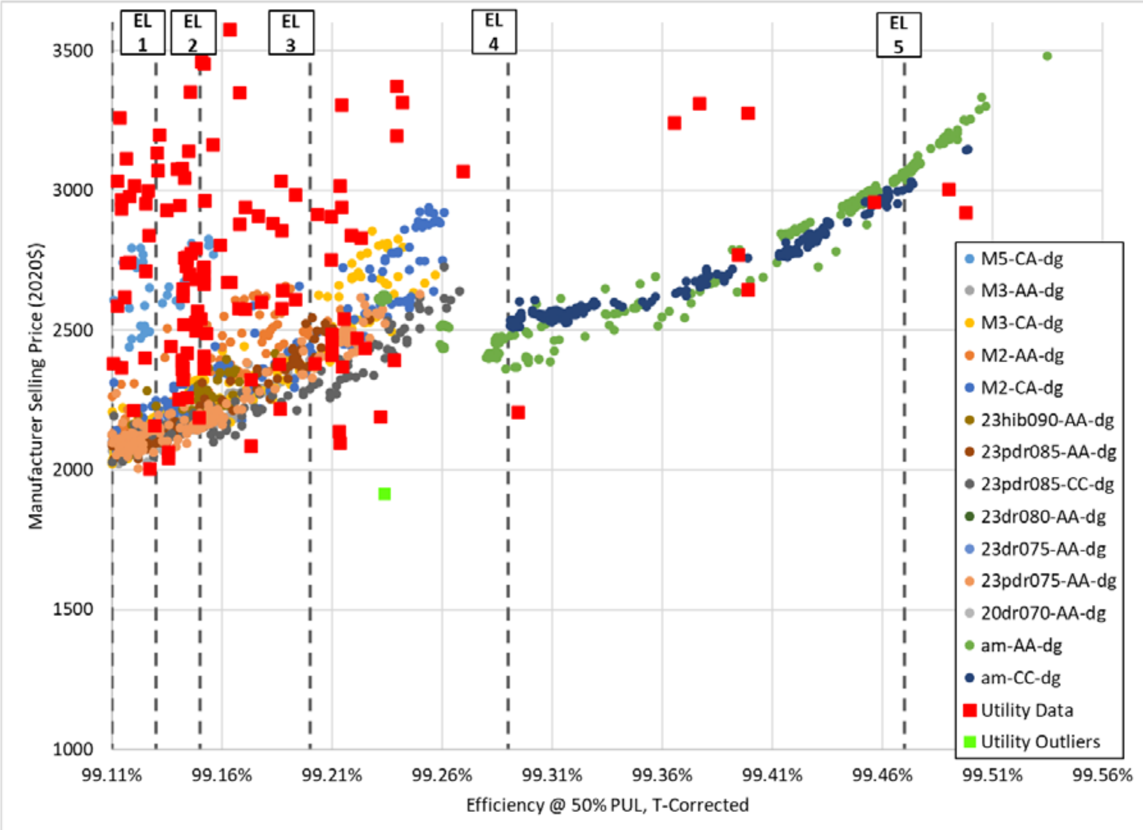


Figure 5.7.2 RU1 – Corrected Data

5.7.4.1 RU2

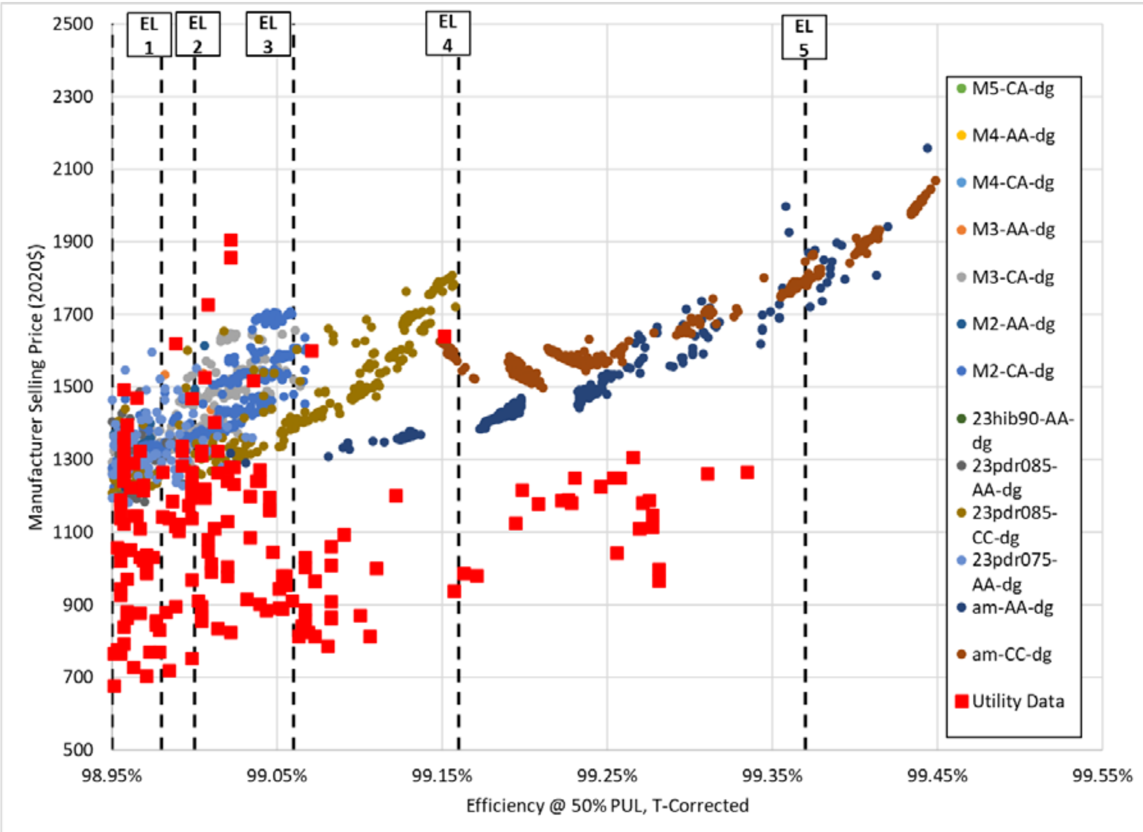


Figure 5.7.3 RU2 – Raw Data

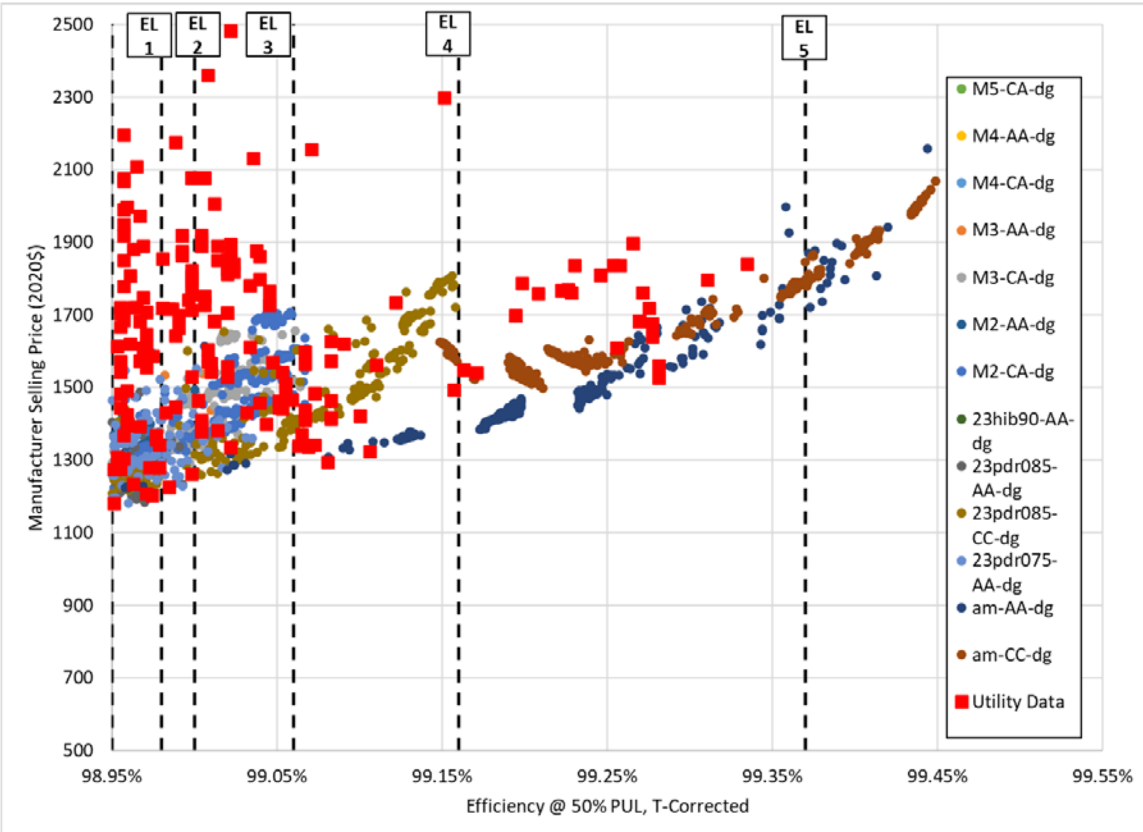


Figure 5.7.4 RU2 – Corrected Data

5.7.4.1 RU3

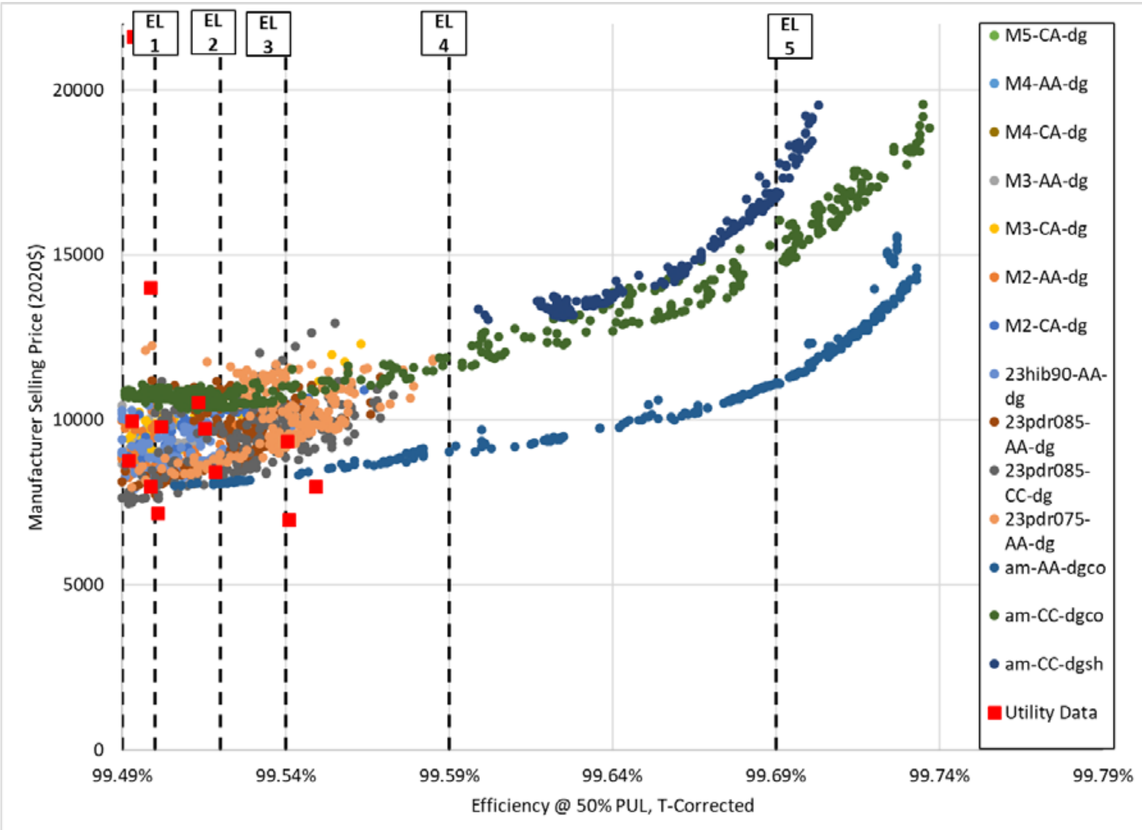


Figure 5.7.5 RU3 – Raw Data

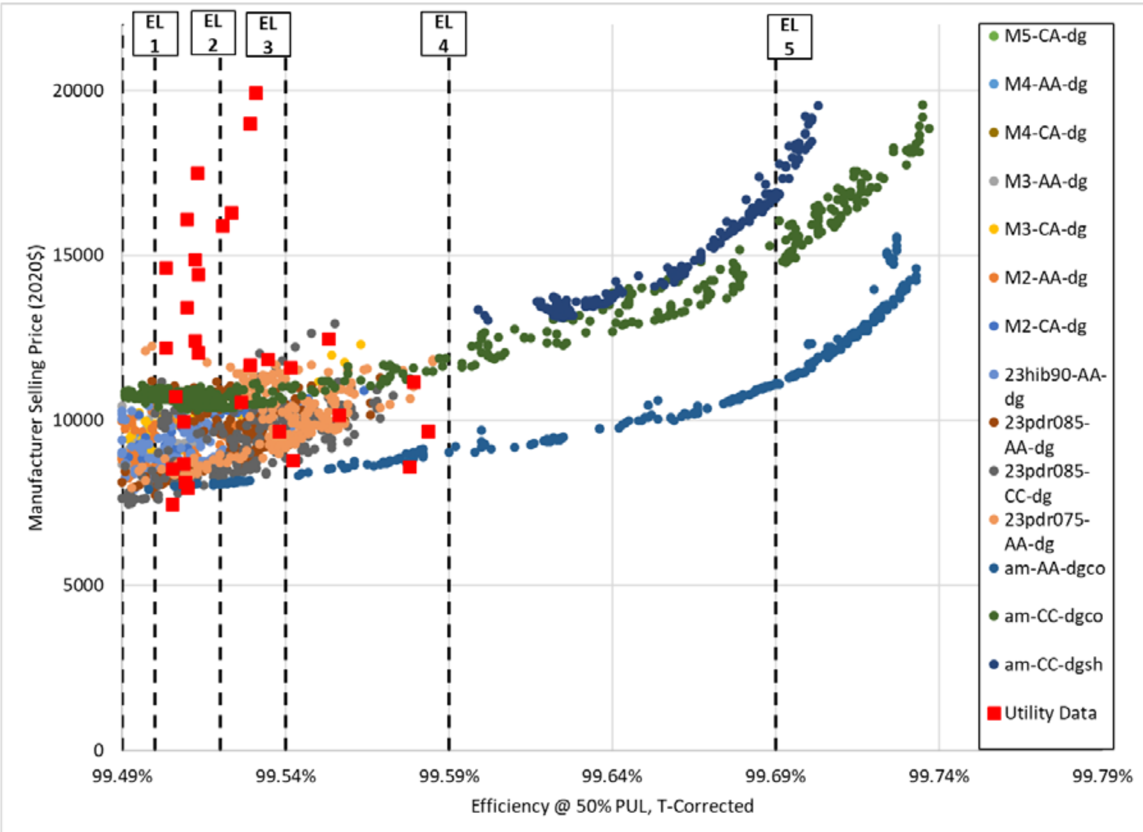


Figure 5.7.6   RU3 – Corrected Data

5.7.4.1 RU4

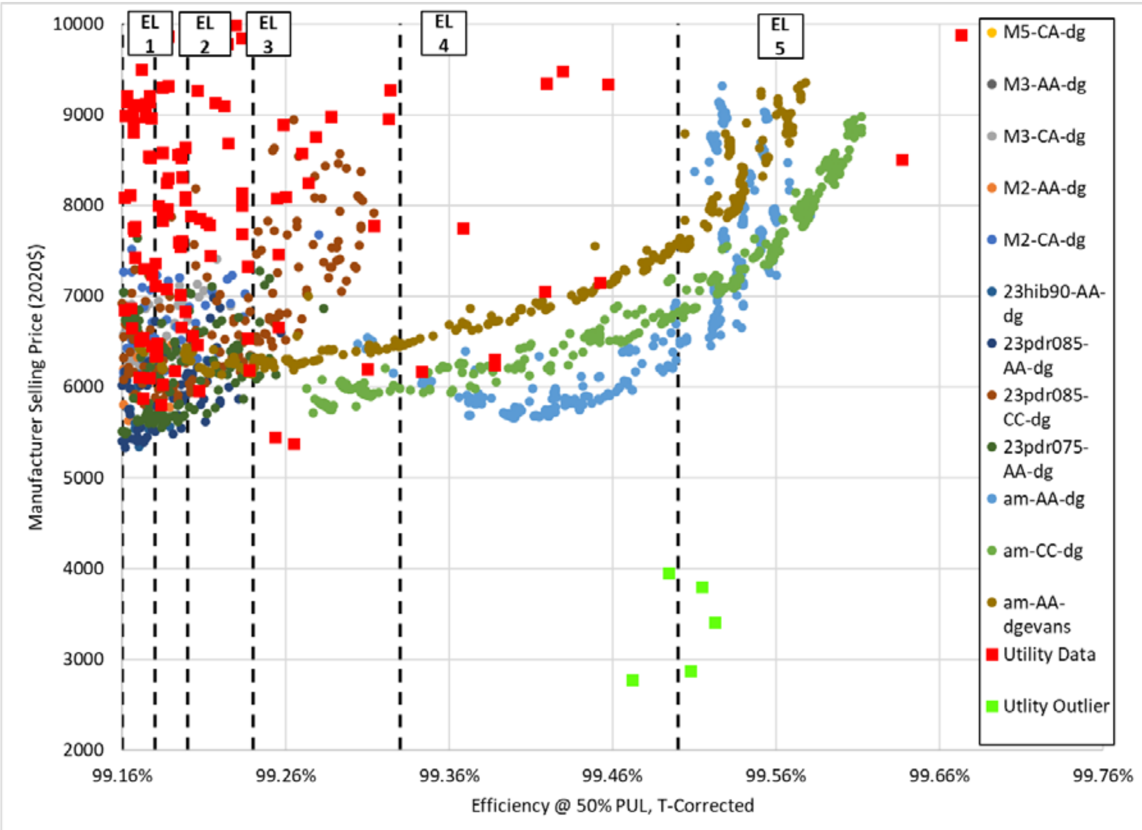


Figure 5.7.7 RU4 – Raw Data

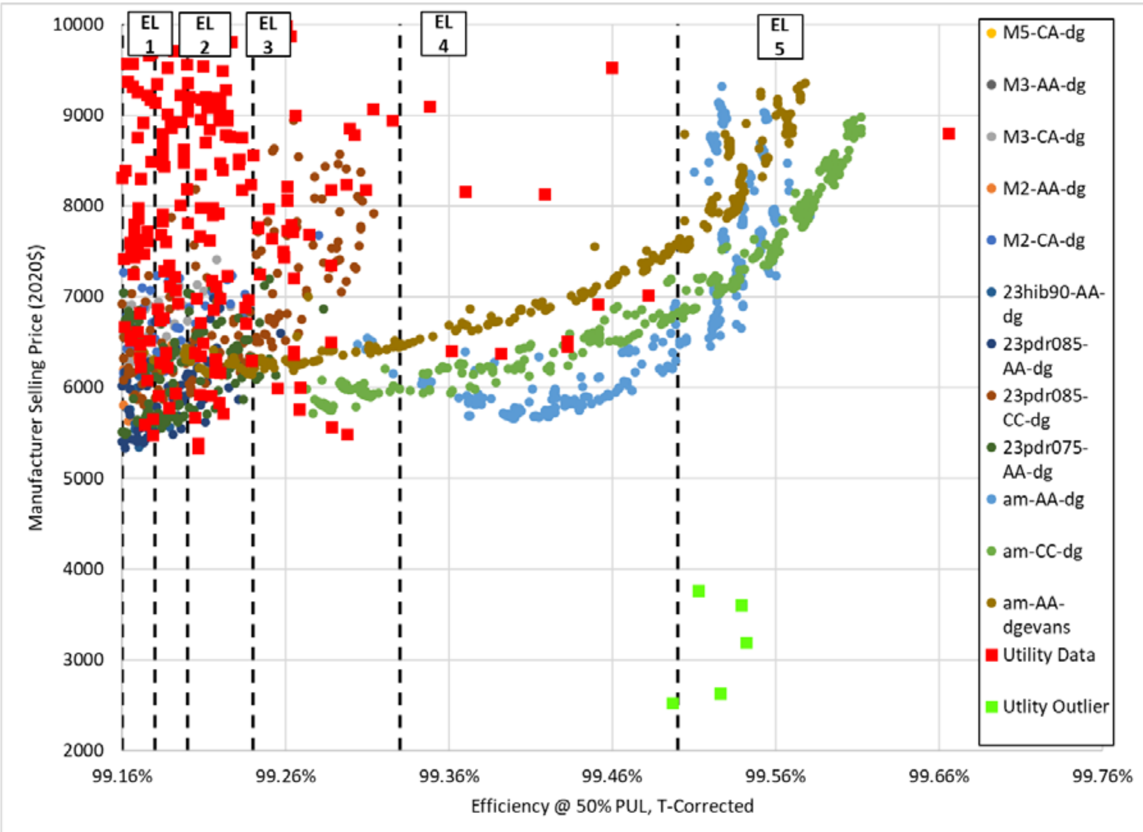


Figure 5.7.8 RU4 – Corrected Data

5.7.4.1 RU5

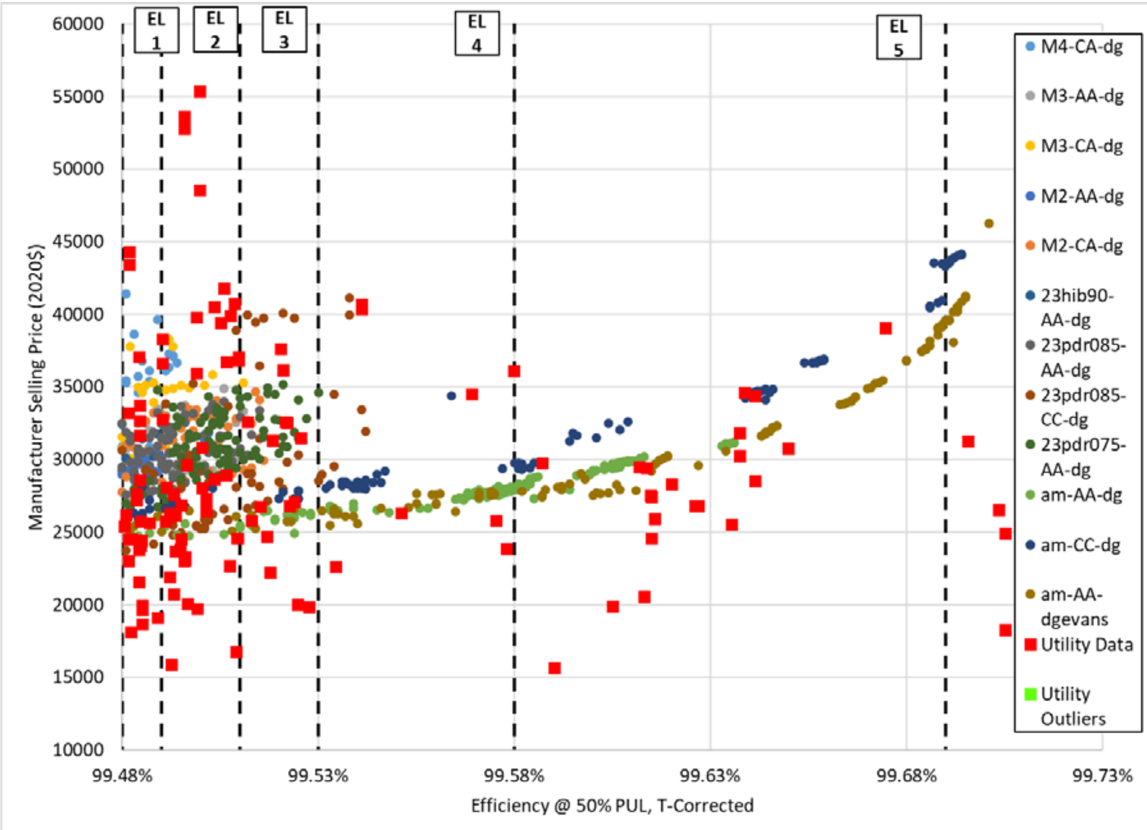


Figure 5.7.9 RU5 – Raw Data

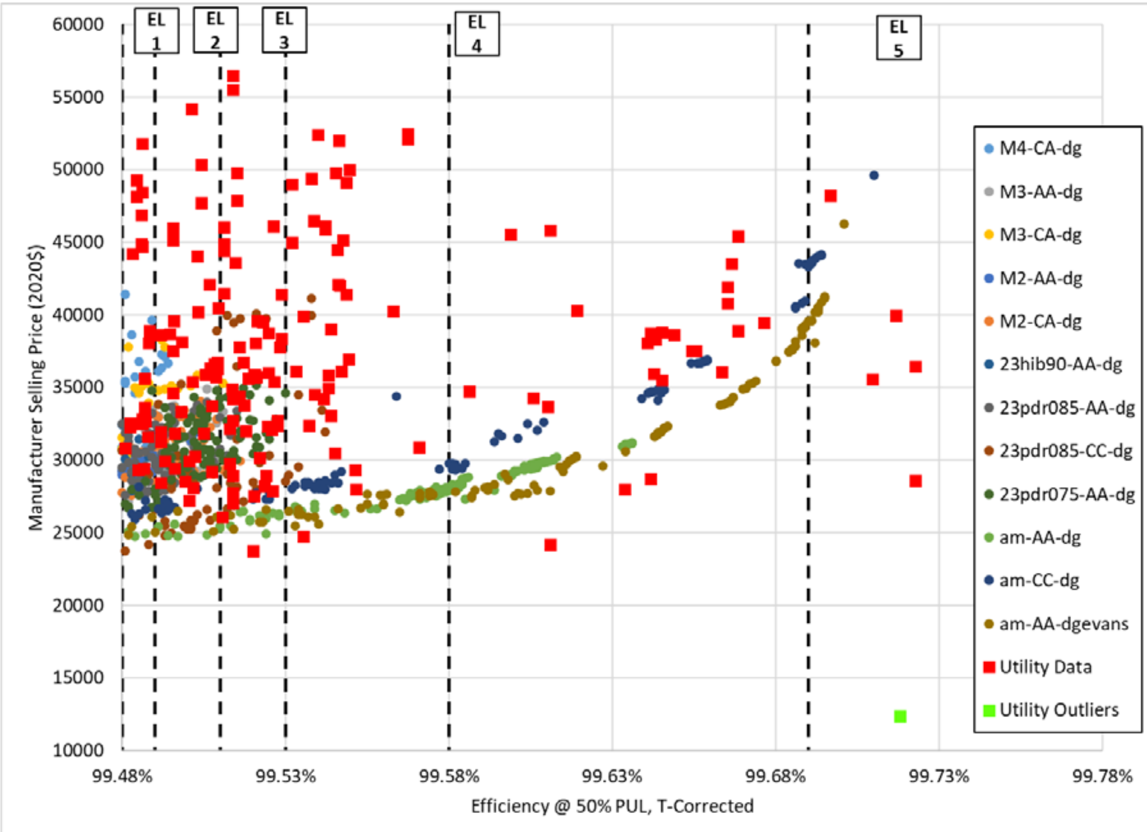


Figure 5.7.10 RU5 – Corrected Data

5.7.5 Low-Voltage Dry-Type Certification Data Plots

The data in this section is organized by representative unit, for which DOE- and CEC-certified data is overlaid atop engineering analysis data. The data is informational; no conclusions are presented. The data is representative of the efficiency bands at which data is currently being certified.

5.7.5.1 RU6

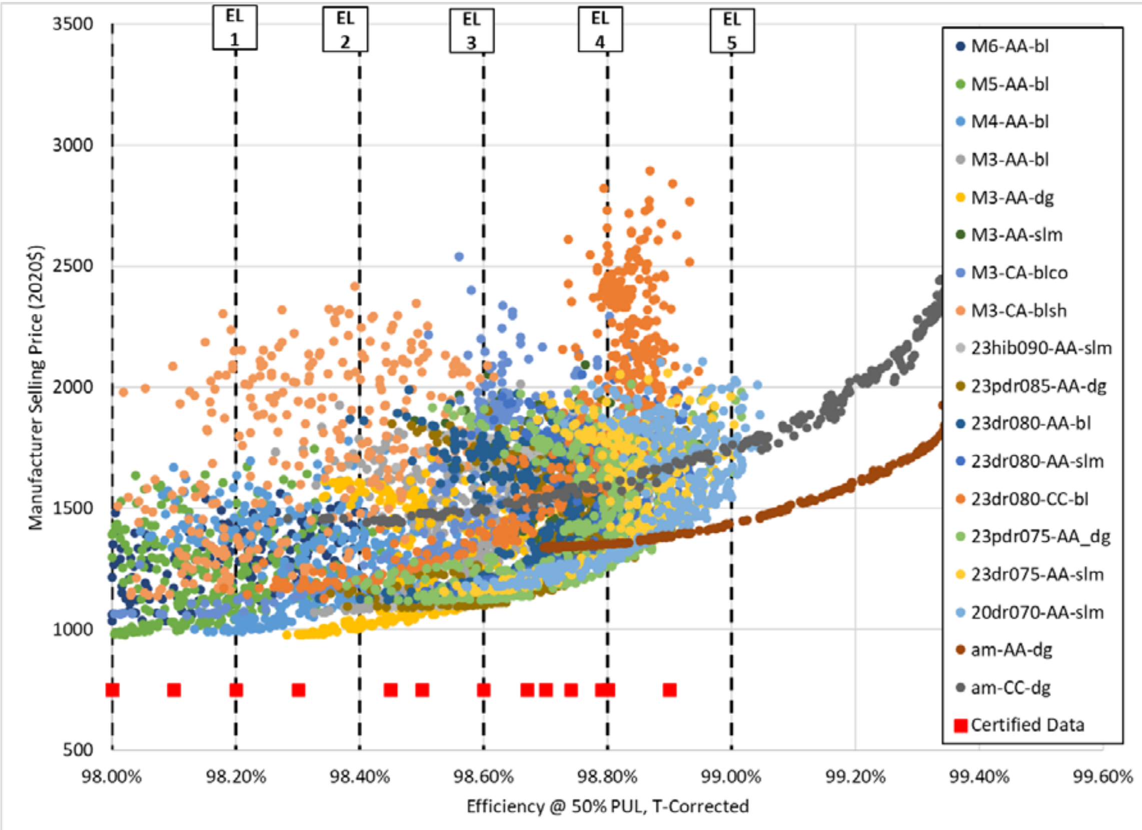


Figure 5.7.11 RU6 – Certified Efficiency Data

5.7.5.2 RU7

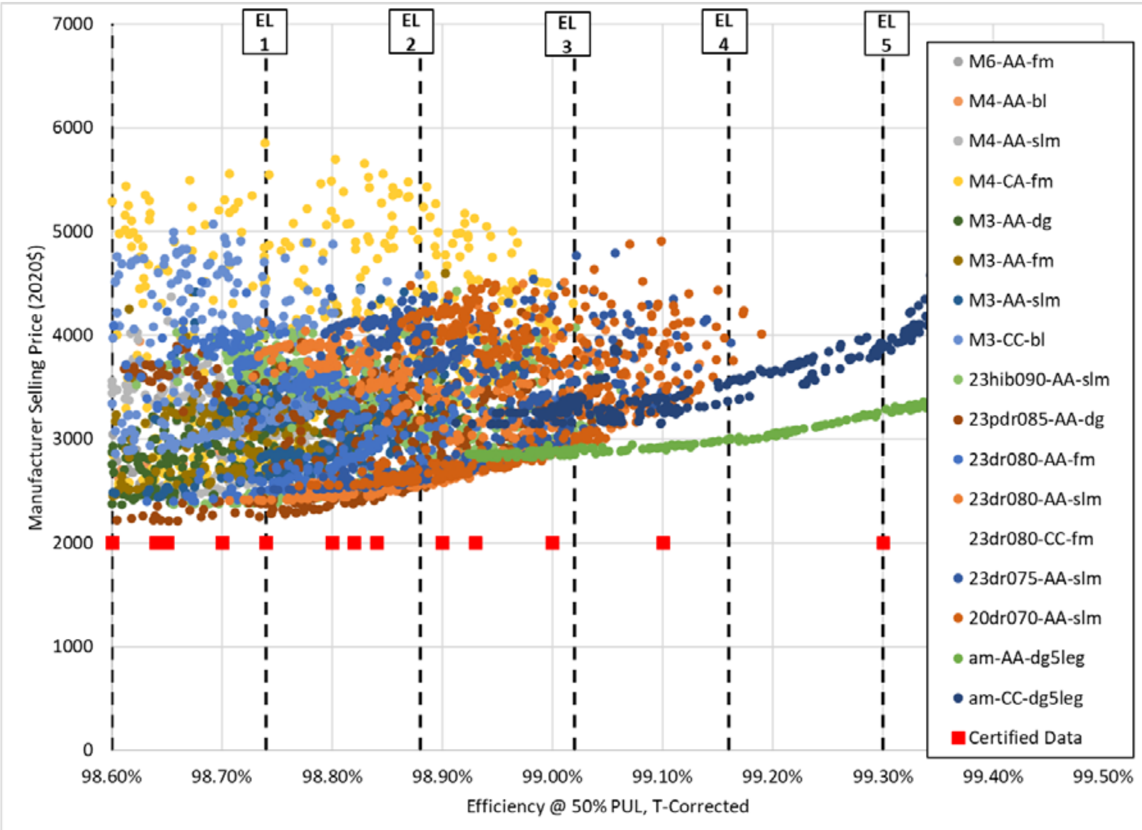


Figure 5.7.12 RU7 – Certified Efficiency Data

5.7.5.1 RU8

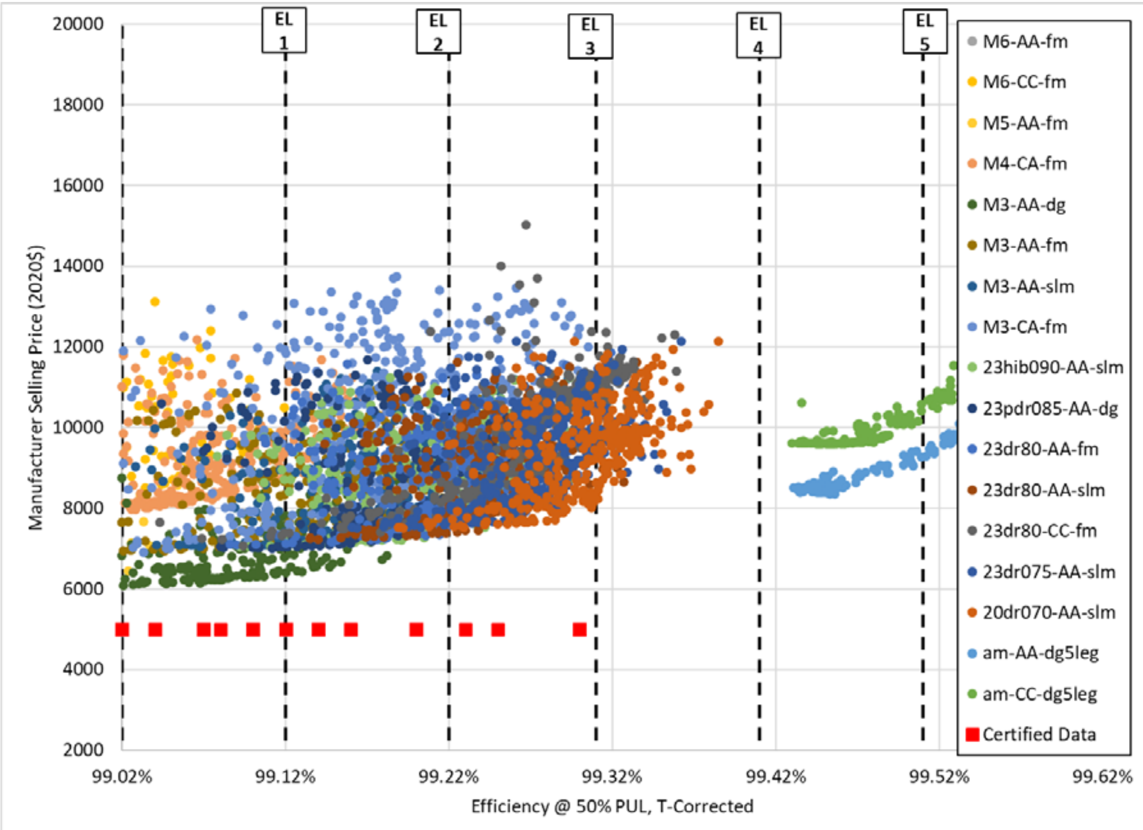


Figure 5.7.13 RU8 – Certified Efficiency Data

5.7.6 Medium-Voltage Dry-Type Certification Data Plots

The data in this section is organized by representative unit, for which DOE- and CEC-certified data is overlaid atop engineering analysis data. The data is informational; and no conclusions are presented. The data is representative of the efficiency bands at which data is currently being certified.

5.7.6.1 RU9

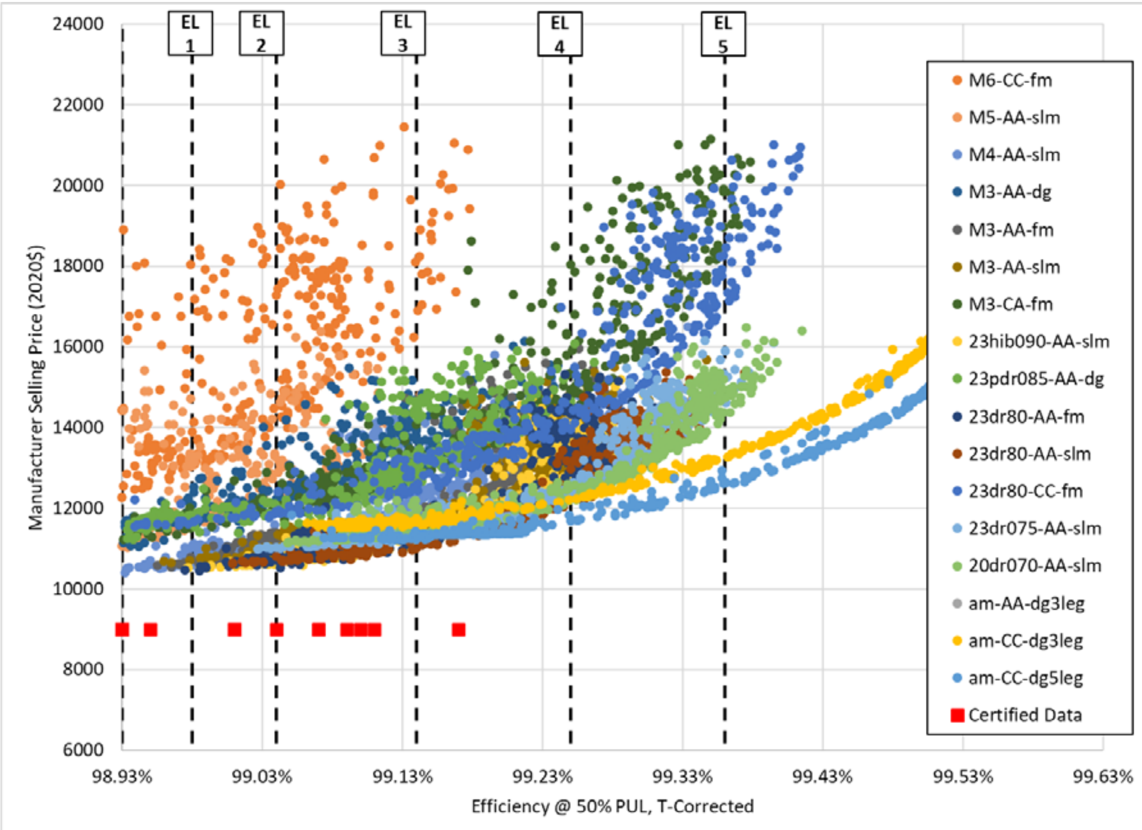


Figure 5.7.14 RU9 – Certified Efficiency Data

5.7.6.2 RU10

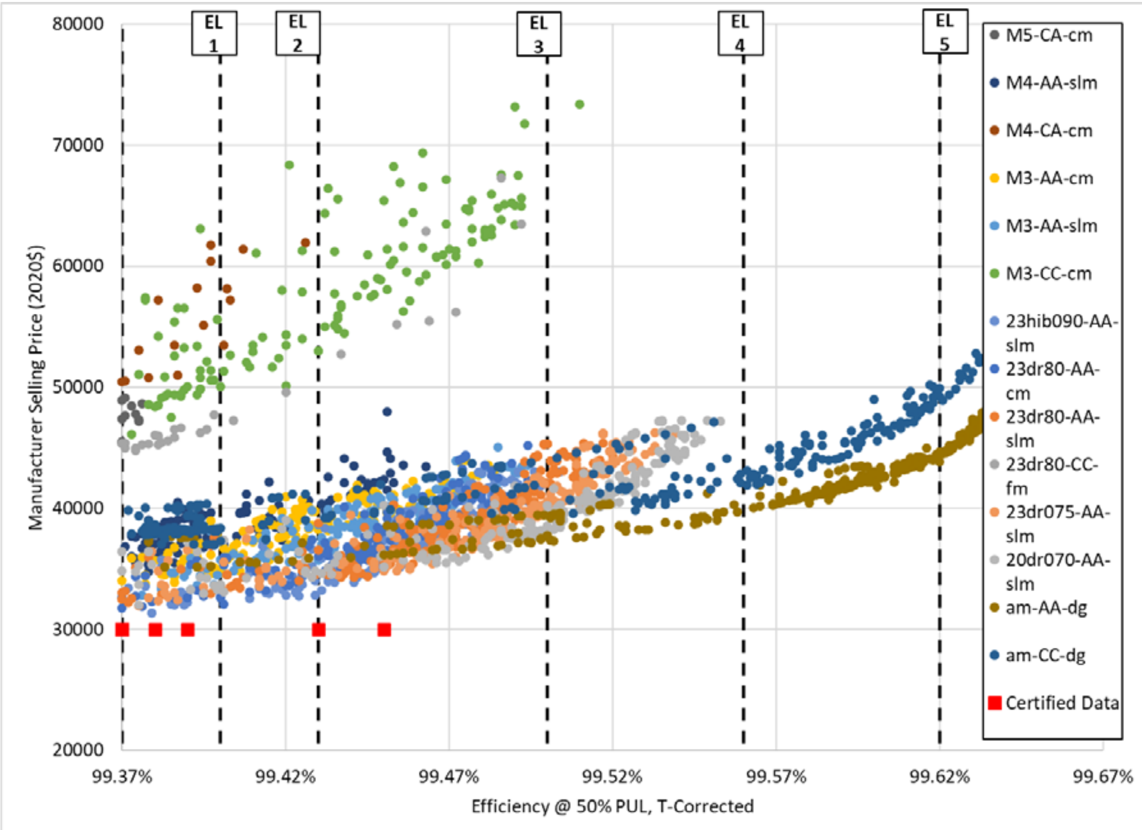


Figure 5.7.15 RU10 – Certified Efficiency Data

5.7.6.3 RU11

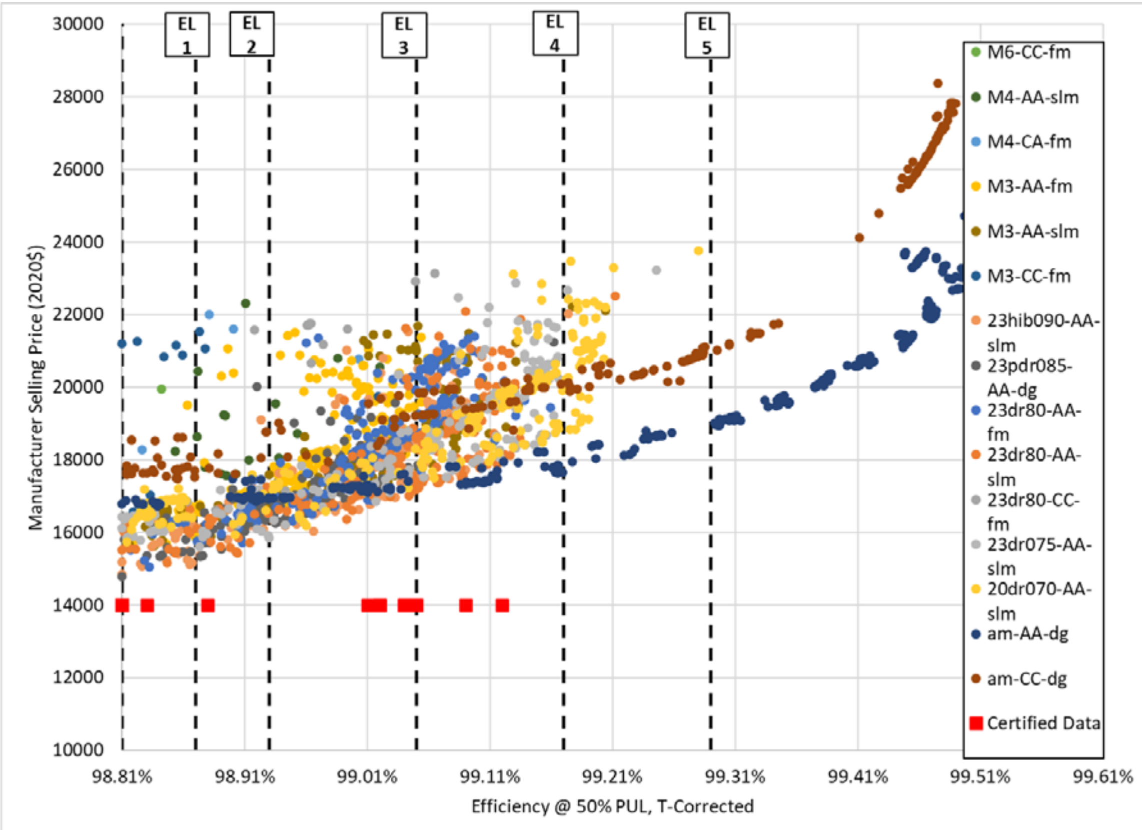


Figure 5.7.16 RU11 – Certified Efficiency Data

5.7.6.4 RU12

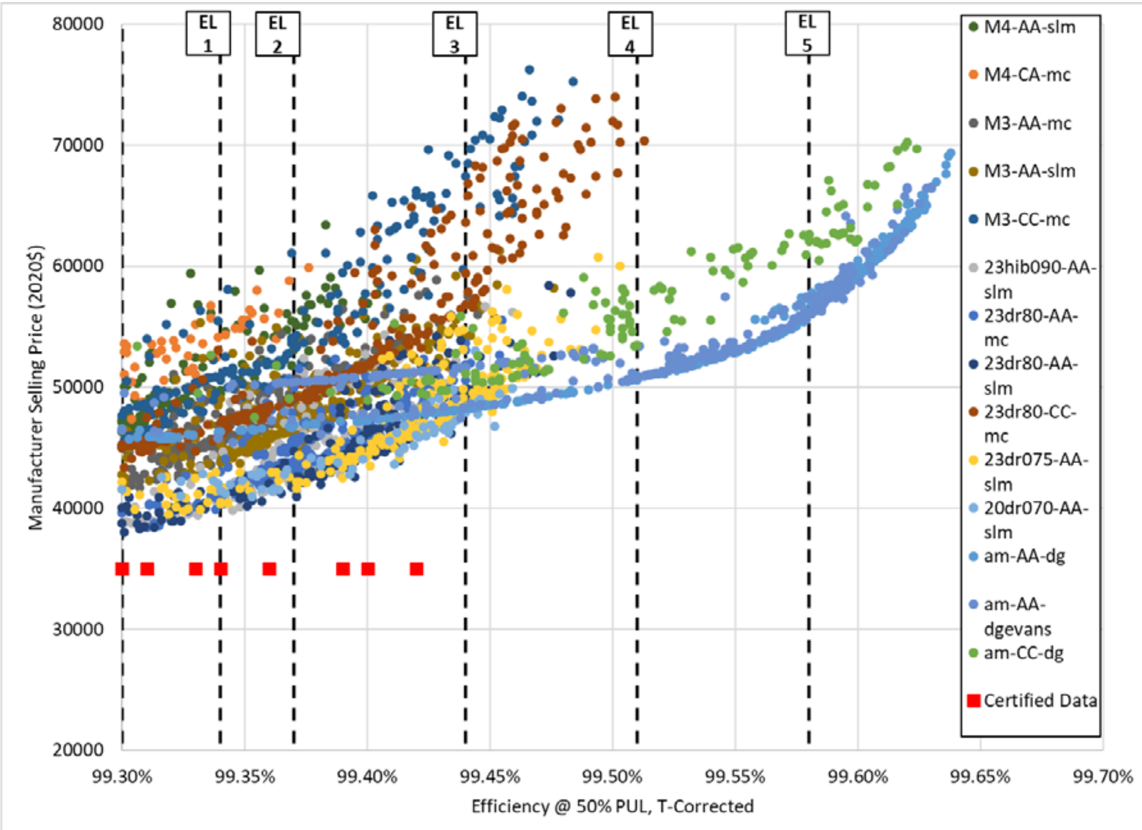


Figure 5.7.17 RU12- Certified Efficiency Data

5.7.6.5 RU13

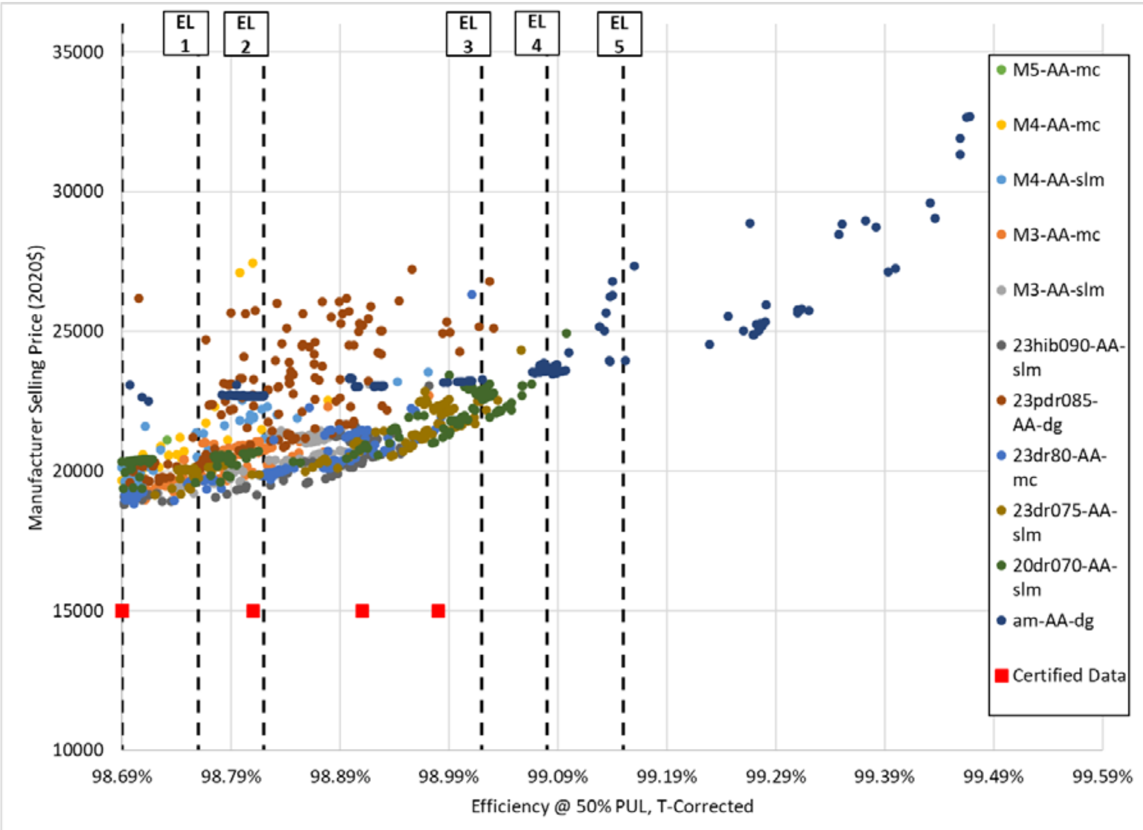


Figure 5.7.18 RU13 – Certified Efficiency Data

5.7.6.6 RU14

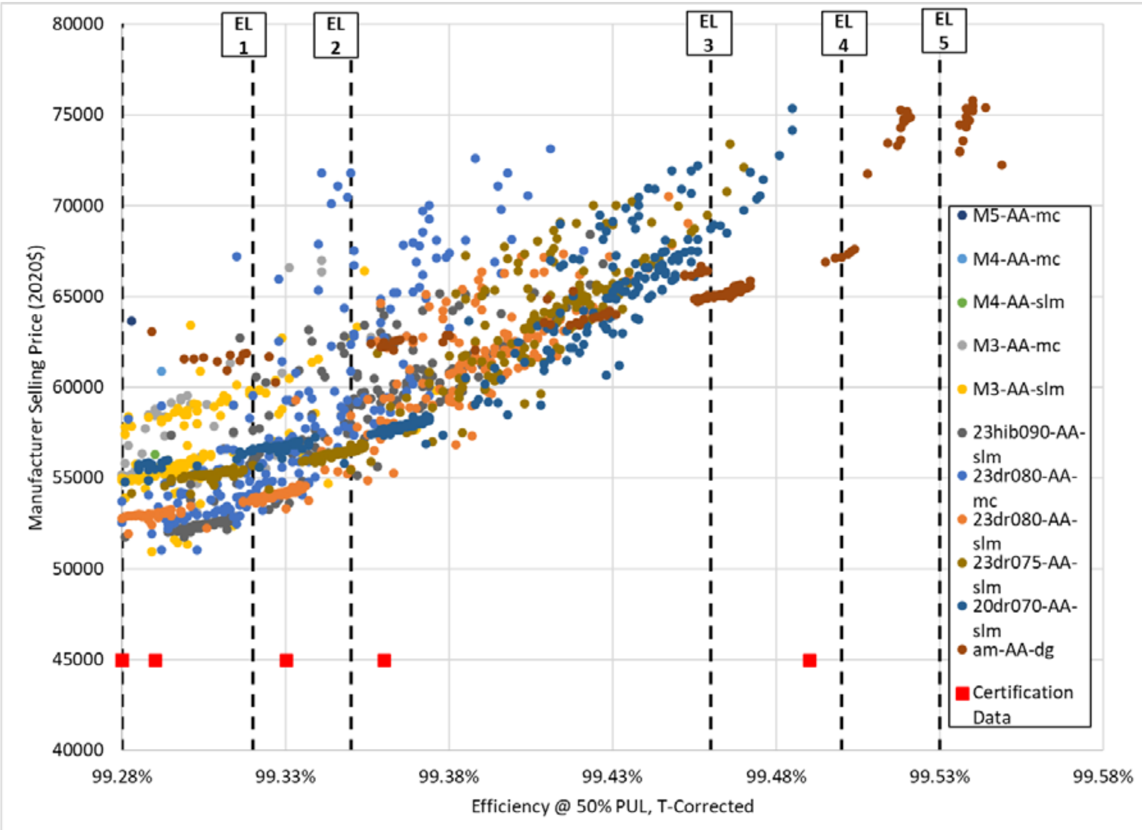


Figure 5.7.19 RU14 – Certified Efficiency Data

REFERENCES

1 Metglas Inc., *Amorphous Alloys for Transformer Cores*. https://metglas.com/wp-content/uploads/2016/12/2605SA1-Magnetic-Alloy.pdf (last accessed on 2018-09-21 at 15:56)

2 Metglas Inc., *Metglas HB1M-LL Transformer Core Alloy*. https://metglas.com/wp-content/uploads/2021/02/Metglas-HB1M-LL-Product-Release-Final.pdf (last accessed on 2021-07-26)

3 Federal Reserve Bank of St. Louis. Economic Research Division. *Federal Reserve Economic Data: Gross Domestic Product: Implicit Price Deflator.* https://fred.stlouisfed.org/graph/?g=FZ2Z (last accessed on 2021-08-06)

CHAPTER 6. MARKUPS AND INSTALLATION COST ANALYSIS

TABLE OF CONTENTS

CHAPTER 6. MARKUPS AND INSTALLATION COST ANALYSIS

6.1 INTRODUCTION

This chapter of the technical support document (TSD) presents the U.S. Department of Energy's (DOE's) method for deriving distribution transformer prices. The objective of the equipment price determination is to estimate the price paid by the customer or purchaser for an installed distribution 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, and 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. Distribution 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 distribution 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 distribution 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 distribution transformers through manufacturer representatives or distributors. The manufacturer selling price plus the distributor markup is generally the utilities' price for transformers. Dry-type distribution transformers go through several additional marketing or handling steps before they are installed by the end-use purchaser.

In general, liquid-immersed 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 distribution transformer sales that are from manufacturers directly to utilities. The fraction of cases, as determined by the amount of electricity reportedly sold by investor owned utilities IOUs in the U.S. Energy Information Administration (EIA) Form 861, is 82 percent.

The manufacturer selling prices for dry-type distribution transformers generally include two price markups: a distributor markup of 15 percent and 26 percent for low- and medium-voltage dry-type distribution 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 2019*[2] and input from interested parties respectively for low- and medium-voltage dry-type distribution 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 distribution 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 and are described in greater detail in chapter 5. Using *RS Means Electrical Cost Data Online 2019*[2] *(RS Means)* 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 MARKUPS

DOE performed a linear regression analysis 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:

$$Total\ Costs\ Including\ O\&P = \alpha + \beta \times Mat + \gamma \times L$$

Where:

Total Costs Including O&P	=	the sum of all bare costs plus overhead and profit = expense (2020$),
Mat	=	the material cost (transformer and hardware) (2018$), adjusted to 2020$ using the GDP price deflator from *BEA*, and
L	=	the direct labor costs of installation (2018$), adjusted to 2020$ using the GDP price deflator from *BEA*,

In this linear regression, α is the constant; β and γ are the variable slopes for material costs and direct labor and equipment costs respectively. 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:

$$Total\ Costs\ Including\ O\&P = 1.10 \times Mat + 1.47 \times L$$

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 variables 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 price of the distribution transformer and a separate markup on the direct labor and equipment costs for the installation.

6.3.1 Dry-Type Distribution Transformer Installed Price Equation

For dry-type distribution 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:

$$Installed\ Price = M_{tax} \times \{M_{Mat} \times [M_{Dist} \times ManPrice]\} + M_L \times L$$

Where:

Installed_Price	=	the final installed price of the transformer (2020$),
M_{tax}	=	the factor that accounts for sales tax, estimated as 1.069,
M_L	=	the factor that accounts for the markup on direct installation labor costs, estimated as 1.47,
L	=	the installation direct labor costs as a function of transformer weight (2018$), adjusted to 2020$ 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 (2020$).

6.3.2 Liquid-Immersed Distribution Transformer Installed Price Equation

The installed price calculation for liquid-immersed distribution transformers differs from that for dry-type distribution 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 distribution transformers to utilities, which account for approximately 81 percent of liquid-immersed transformer shipments. The fraction of utilities that purchase directly from manufacturers is based on the percent of electricity sales by independently owned utilities in the *EIA's Form 861*[2] database. This sales channel removes a distributor markup. The inclusion of this channel reduces the overall markup for liquid-immersed transformers.

$$Installed\ Price = M_{tax} \times \{[M_{Dist} \times ManPrice]\} + M_L \times L$$

Where:

Installed_Price	=	the final installed price of the transformer (2020$),
M_{tax}	=	the factor that accounts for sales tax, estimated as 1.069,
M_L	=	the factor that accounts for the markup on direct installation labor costs, estimated as 1.47,
L	=	the installation direct labor costs as a function of transformer weight (2018$), adjusted to 2020$ 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 (2020$).

REFERENCES

1. Department of Energy - Office of Energy Efficiency and Renewable Energy Energy Conservation Program for Commercial Equipment: Distribution Transformers Energy Conservation Standards; Proposed Rule. *Federal Register* 71, No. **150**, 44373 (2006).

2. RSMeans Electrical Cost Data Online. *Electrical Cost Data Online* (2019).at <http://rsmeans.reedconstructiondata.com/66003.aspx>

3. The Sales Tax Clearinghouse State Sales Tax Rates. *theSTC - State Sales Tax Rates* at <http://www.thestc.com/STrates.stm>

4. U.S. Department of Commerce-Bureau of Economic Analysis National Economic Accounts: National Income and Product Accounts Tables (1969-Present). at <http://www.bea.gov/national/nipaweb/DownSS2.asp>

CHAPTER 7. ENERGY USE ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 7. ENERGY USE ANALYSIS

7.1 INTRODUCTION

The U.S. Department of Energy (DOE) characterized energy use and end-use load for distribution transformers. These 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 energy use and end-use loads 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 are a function of 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 commonly 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 no-load losses and then presents the details of the separate load characterization models that DOE developed for liquid-immersed and dry-type distribution 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.

$$\boldsymbol{E_T} = \in_{NLL} + \boldsymbol{E} + \in_{LL} \left(\boldsymbol{E} / \boldsymbol{E_{max}} \right)^2$$

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 distribution 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 distribution transformers are owned by electric utilities, the appropriate electricity price for those transformers is the cost of electricity production (the costs associated with delivering electricity to the distribution system), 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 distribution 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 HOURLY LOAD MODEL FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

This section describes the hourly load model DOE developed for liquid-immersed distribution transformers. The load model is used to estimate hourly loads over an entire year for individual transformers, in order to estimate the operating cost savings from replacing an individual transformer with a more efficient one as part of DOE's life-cycle cost (LCC) analysis.

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 distribution 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, and a joint probability distribution between transformer and system load levels. The steps in the operation of the hourly load simulation program are summarized 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 its share of total national kilowatt-hours sold.

3. The program selects the customer type (residential or C&I) served by the transformer and the appropriate sample weight for that customer type. The weight is assigned based on the fraction of that utility's total electricity sales to that customer type.

4. Each customer is assigned a transformer load and system load joint probability distribution function (JPDF) which predicts the transformer load given the system load. The joint distribution function is based on the customer type and the size of the load associated with the customer.

5. 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 individual steps in the loop are as follows.

    a. Randomly select 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 based on the JPDF.

6. 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 estimated transformer load losses and operating costs. The program provides this output for the number of individual transformers necessary to total the annual kilowatt-hours generated by each utility

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 distribution 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 Schedule 2, the annual sales in megawatt-hours for each utility to the residential, commercial, and industrial sectors. Form 861's Schedule 8 lists all the utilities that own electricity distribution equipment and the states in which that equipment is located. Based on those data, DOE created a list of utilities that own transformers and assigned a sample weight to each based on the electricity sales of that utility to each sector.

The second type of utility information used in the hourly load model 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) , as illustrated in Figure 7.2.1.[2] The regions represent both National reliability regions and, where they exist, integrated wholesale electricity markets. Each region in turn comprises a number of electric utility control area operators (CAOs), some of which may also be utility companies. DOE obtained reported hourly load and system lambda data for regions without wholesale markets, and day-ahead market price data for market regions from independent system operators, from the Federal Energy Regulatory Commission (FERC) Form 714 database.[3] Lambda is defined approximately as the operating cost of the generating unit on the dispatch margin. DOE aggregated the hourly data by EMM to produce regional time series for each EMM region.

Appendix 7B contains the list of National entities, along with their designated CAO and EMM regions, for which DOE obtained the FERC data used to create the hourly time series.

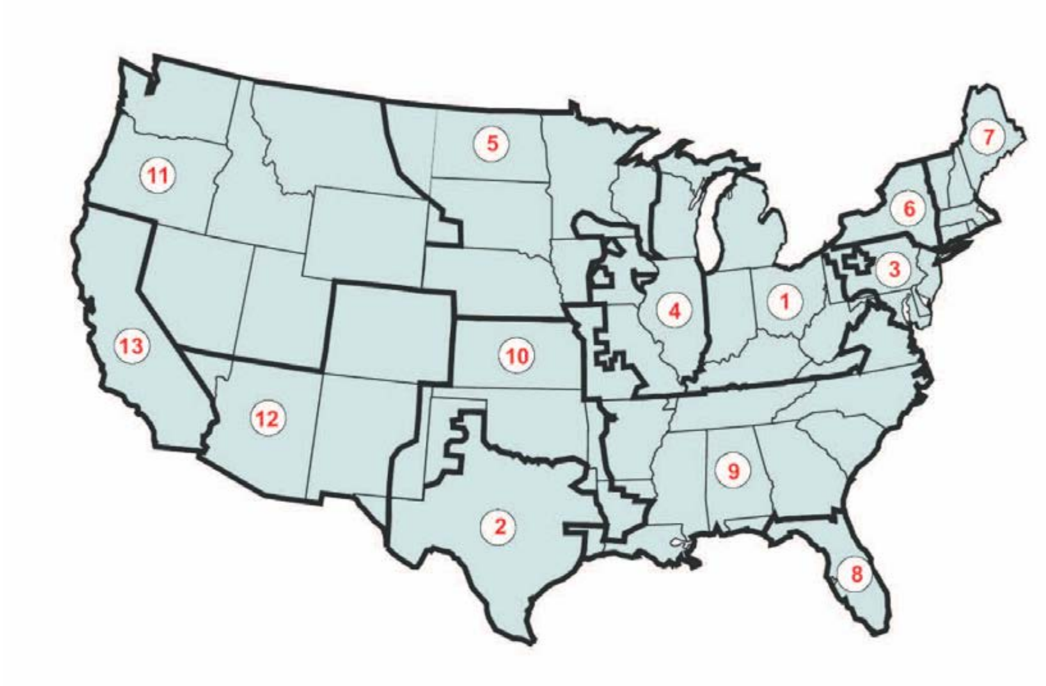


Figure 7.2.1 Electricity Market Module Regions in the National Energy Modeling System

The numbered regions in Figure 7.2.1 are listed in Table 7.2.1.

Table 7.2.1 Definition of Electricity Market Module Regions in the National Energy Modeling System

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 Distribution Transformer Loading

DOE used a distribution of values for initial peak loading to characterize the annual peak load served by each distribution 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 over time. 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 eventually be served, and engineers generally use a discrete set of transformer ratings that are imperfectly matched with the expected peak load. 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.

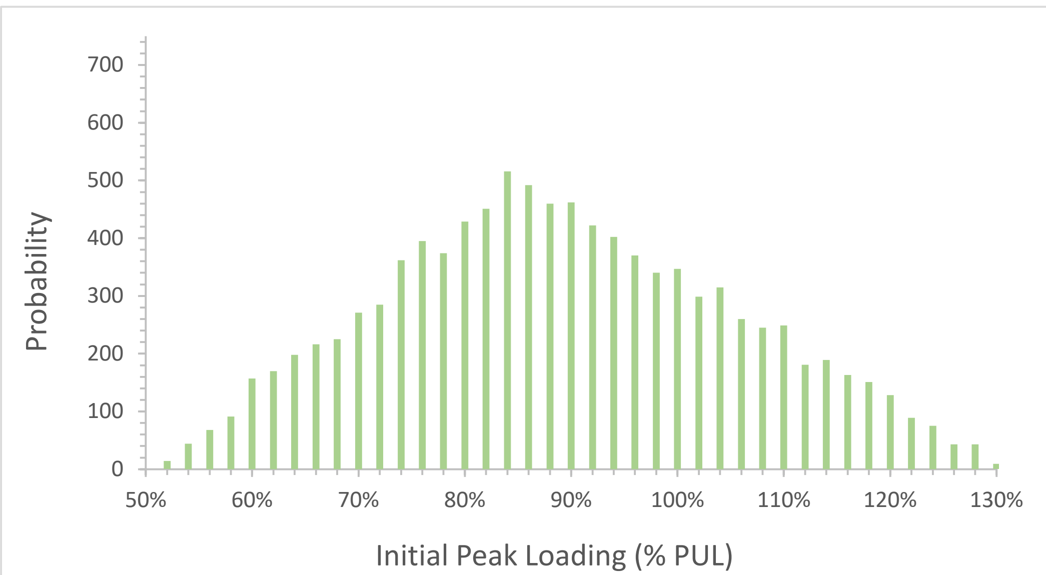


Figure 7.2.2 Distribution of Initial Peak Loading Used in the Hourly Load Analysis

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]. 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, from independent system operators. DOE used data for 2015 and scaled it to the year of analysis 2020 using Annual Energy Outlook 2021.

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 as system load increases. 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 $delta_j$ 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 7A.

Within the LCC model, 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. While the bin sizes are variable and depend on region, fifteen system load bins are used for each region.

7.2.1.4 Distribution Transformer Load Simulation Inputs

DOE studied the loads on individual liquid-immersed distribution transformers for residential and non-residential customers by analyzing a dataset of hourly loads for more than 60,000 transformers from 152 zip codes across Virginia and parts of North Carolina, provided by interested parties. It was determined that most of the transformers for which load data were provided served customers within the PJM Dominion Hub transmission zone of the PJM Interconnection ISO region. For the purpose of this rulemaking, the system load associated with the transformer load received by DOE was assumed to be the load observed at the PJM Dominion Hub.

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 those load losses. To estimate the correlation between peak transformer load and system load, DOE constructed joint probability distribution functions (JPDFs) for each transformer based on the provided transformer load and the system load data associated with the PJM Dominion Hub region. DOE estimated the JPDFs by defining a set of bins for both the system load and individual transformer 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 each transformer, and specified the customer type and load size associated with each. Further details of the transformer dataset are provided in Appendix 7-C, along with the methodology adopted for generating the JPDFs described in Appendix 7A.

Figure 7.2.3 and Figure 7.2.4 show separate color plots of the JPDF for engineering representative units 1 and 5. 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.

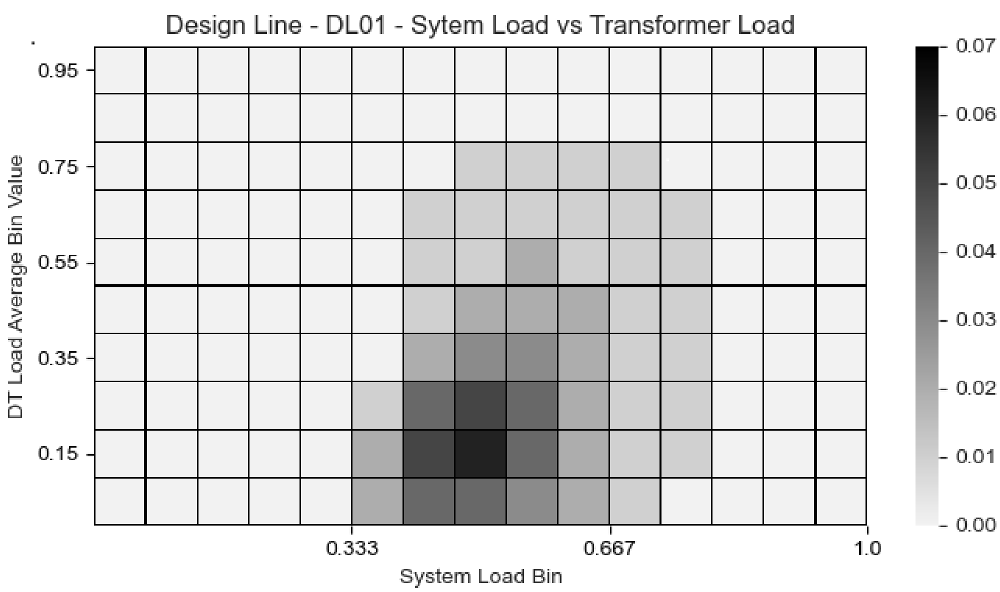


Figure 7.2.3 Average Joint Probability Distribution for Representative Unit 1

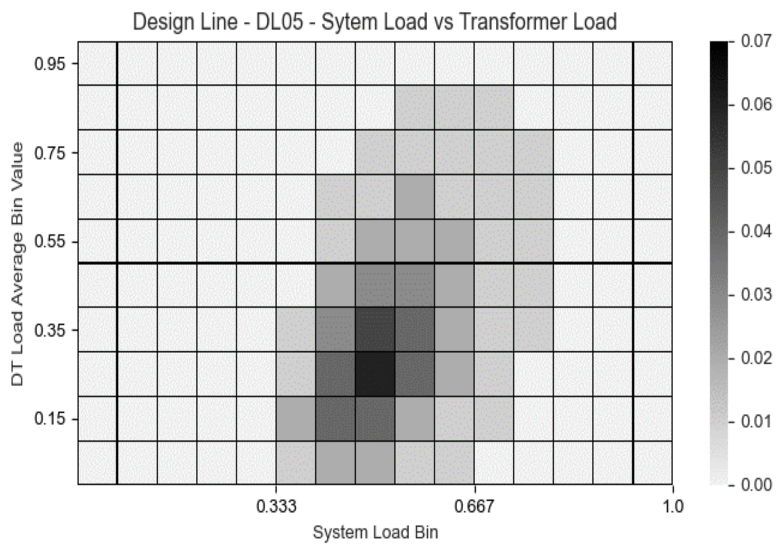


Figure 7.2.4 **Average Joint Probability Distribution for Representative Unit 5**

7.2.2 Hourly Load Model Results

Table 7.2.2 Average First Year Losses and Energy Savings by Liquid-immersed Rep Units

Rep Unit	Candidate Standard Level	Load Losses (kWh)	No-load Losses (kWh)	Energy Use (kWh)	Energy Savings (kWh)
1	0	368	870	1238	
1	1	350	865	1215	24
1	2	323	908	1231	8
1	3	301	857	1158	80
1	4	402	329	731	507
1	5	257	353	610	628
2	0	175	503	679	
2	1	154	547	701	-22
2	2	182	419	601	78
2	3	203	201	404	275
2	4	172	218	390	289
2	5	101	263	364	314
3	0	2715	4441	7157	
3	1	3013	3499	6512	645
3	2	3146	2920	6066	1091
3	3	3315	1689	5003	2154
3	4	2832	1715	4547	2609
3	5	1797	2230	4026	3131
4	0	785	2598	3384	
4	1	801	1872	2673	710
4	2	841	1224	2065	1318
4	3	846	1153	1999	1385
4	4	820	1173	1993	1391
4	5	594	1287	1881	1502
5	0	8459	8831	17289	
5	1	8082	9125	17207	82
5	2	8976	6417	15394	1896
5	3	8758	5889	14647	2642
5	4	7519	6506	14025	3264
5	5	4524	7644	12168	5121

7.3 MODEL FOR DRY-TYPE DISTRIBUTION 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 commercial or industrial customers, 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 from the EIA's Commercial Buildings Energy Consumption Surveys (CBECS) for 1992, 1995, and 2012. DOE assumed that each building has a distribution 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 appropriate local electricity tariff. In this analysis, DOE used a previous, detailed study of commercial building energy prices,[6] which indicated 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.

Distribution 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 distribution 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 commercial and industrial customers.

7.3.2 Monthly Load Simulation

The monthly load simulation model embedded in the LCC simulation 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 distribution 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 distribution transformer load, transformer loss factor, and coincident peak transformer load.

7.3.3.1 Customer Data

The customer sample for the dry-type distribution 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 2012). The building categories used to define the sample 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 distribution 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 use for large industrial and commercial customers are similar. It verified this assumption by comparing load factor distributions of industrial and commercial 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 2014 Manufacturing Energy Consumption Survey[10] to estimate the total floorspace of industrial buildings that would contain distribution 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 with annual peak loads less than the assumed design capacity of the distribution transformer were excluded from the analysis. The customer sample contains a range of building sizes having a wide range of annual peak loads. Although larger buildings undoubtedly contain multiple distribution 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 distribution 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 Distribution Transformer Load

Initial peak load is the annual peak load on the distribution transformer in the first year of operation divided by its rated capacity. Similar to the Initial Peak Load for liquid-immersed described in section 7.2.1.2, DOE used a distribution of initial peak load for low-voltage, dry-type distribution transformers has a constant probability between 60 percent and 90 percent of nameplate capacity; the distribution for medium-voltage, dry-type distribution transformers has a constant probability between 70 percent and 100 percent of nameplate capacity.

7.3.3.3 Distribution 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.

In DOE's analysis, the characteristics of distribution transformer load for commercial and industrial 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 interested parties.

7.3.3.4 Coincident Peak Load

Coincident peak load (*CPL*) captures the coincidence between a distribution transformer's load and the building's peak load. For a building that has a single distribution transformer, the coincidence would be perfect, and the *CPL* would equal one. In practice, the degree of coincidence depends on how distribution 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 7A.

7.3.4 Monthly Load Model Results

Table 7.3.1 Average First Year Losses and Energy Savings by Low-voltage Dry-Type Rep Units

Rep Unit	Candidate Standard Level	Load Losses (kWh)	No-load Losses (kWh)	Energy Use (kWh)	Energy Savings (kWh)
6	0	260	601	861	0
6	1	254	540	794	67
6	2	237	480	717	143
6	3	221	446	666	195
6	4	143	478	620	241
6	5	192	139	331	530
7	0	688	1301	1989	0
7	1	667	1289	1957	33
7	2	611	1324	1935	55
7	3	612	869	1481	509
7	4	671	468	1139	851
7	5	541	439	980	1010
8	0	1741	4654	6396	0
8	1	1732	4435	6167	228
8	2	1569	4331	5900	496
8	3	1471	3374	4845	1551
8	4	1660	1409	3069	3327
8	5	1661	1392	3053	3342

Table 7.3.2 Average First Year Losses and Energy Savings by Medium-voltage Dry-Type Rep Units

Rep Unit	Candidate Standard Level	Load Losses (kWh)	No-load Losses (kWh)	Energy Use (kWh)	Energy Savings (kWh)
9	0	4461	4564	9025	0
9	1	4403	4485	8888	137
9	2	4220	4376	8596	429
9	3	4037	2753	6790	2235
9	4	4047	1792	5839	3186
9	5	3099	1950	5049	3976
10	0	12153	15596	27749	0
10	1	10715	16042	26757	992
10	2	9461	16510	25971	1777
10	3	9910	8909	18818	8930
10	4	8465	9204	17669	10080
10	5	6383	9278	15661	12087
11	0	4275	6847	11121	0
11	1	3824	7045	10868	253
11	2	3588	6685	10273	848
11	3	4214	3135	7350	3772
11	4	4089	2688	6777	4344
11	5	3045	2908	5953	5169
12	0	12209	20707	32916	0
12	1	10925	20607	31532	1384
12	2	9613	20970	30583	2334
12	3	11919	9630	21549	11367
12	4	10785	9831	20616	12300
12	5	7427	10972	18399	14517
13	0	4531	7899	12430	0
13	1	3903	8123	12027	403
13	2	3657	7862	11519	911
13	3	2851	6693	9544	2886
13	4	4502	3133	7635	4795
13	5	3935	3228	7162	5268
14	0	13857	31841	45697	0
14	1	13865	29717	43582	2115
14	2	9541	33317	42858	2839
14	3	18048	11389	29438	16260
14	4	15841	11686	27527	18171
14	5	12212	12789	25002	20696

REFRENCES

1. U.S. Department of Energy-Energy Information Administration. Form EIA-861: Annual Electric Power Industry Database. (2020). at <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

2. Energy Information Administration - Office of Integrated Analysis and Forecasting. *The National Energy Modeling System (NEMS): An Overview*. (U.S. Department of Energy, 2020). at <http://www.eia.doe.gov/oiaf/aeo/overview/>

3. U.S. Department of Energy-Federal Energy Regulatory Commission. *Form No. 714 - Annual Electric Control and Planning Area Report*. (U.S. Department of Energy-Federal Energy Regulatory Commission, 20015). at <http://www.ferc.gov/docs-filing/forms/form-714/overview.asp>

4. M. E. de Oliveira, A. Padilha-Feltrin & F. J. Candian. Investigation of the Relationship between Load and Loss Factors for a Brazilian Electric Utility. in (IEEE, 2006). doi:10.1109/TDCLA.2006.311390

5. U.S. Department of the Interior - Bureau of Reclamation. Permissible Loading of Oil-Immersed Transformers and Regulators. (1991).

6. Pratt, R. G., Williamson, M. A., Richman, E. E. & Miller, N. E. Commercial Equipment Loads: End-Use Load and Consumer Assessment Program (ELCAP). (1990).

7. U.S. Department of Energy-Energy Information Administration. 1992 Commercial Buildings Energy Consumption Survey (CBECS). (1992). at <http://www.eia.doe.gov/emeu/cbecs/92microdat.html>

8. U.S. Department of Energy-Energy Information Administration. 1995 Commercial Building Energy Consumption and Expenditures (CBECS). (1995). at <http://www.eia.gov/emeu/cbecs/microdat.html>

9. U.S. Department of Energy-Office of Building Technologies. in *Distribution Transformers Energy Conservation Standard Technical Support Document* (U.S. Department of Energy-Office of Building Technologies, 2007). at <http://www.regulations.gov/#!documentDetail;D=EERE-2006-STD-0099-0005>

10. U.S. Department of Energy-Energy Information Administration. 20014 Manufacturing Energy Data Tables (MECS). (2018). at <http://www.eia.doe.gov/emeu/mecs/mecs2006/2006tables.html>

11. Institute of Electrical and Electronic Engineers (IEEE). *Draft Guide for Distribution Transfomer Loss Evaluation*. (IEEE, 2001).

12. Hopkinson, P. ANOPR for Distribution Transformers, EERM/STD-00-550, SNOPR and ANOPR Comments, comment No. 65, p. 3. (2004).

CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSES

8.1 INTRODUCTION

This chapter describes the U.S. Department of Energy's (DOE's) method for analyzing the economic impacts on individual consumers from potential energy efficiency standards for distribution transformers.[a] The effects of standards on individual consumers include a change in purchase price (usually an increase) and a change in operating costs (usually a decrease). This chapter describes three metrics DOE used to determine the impact of standards on individual consumers:

- **Life-cycle cost** (LCC) is the total consumer expense during the lifetime of an appliance (or other equipment), including purchase expense and operating costs (including energy expenditures). DOE discounts future operating costs to the year of purchase and sums them over the lifetime of the product.
- **Payback period** (PBP) measures the amount of time it takes a consumer to recover the higher purchase price of a more energy efficient product through lower operating costs. DOE calculates a simple payback period which does not discount operating costs.
- **Rebuttable payback period** is a special case of the PBP. Whereas LCC is estimated for a range of inputs that reflect real-world conditions, rebuttable payback period is based on laboratory conditions as specified in the DOE test procedure.

Inputs to the LCC and PBP calculations are described in 8.2, and 8.3. Results of the LCC and PBP analysis are presented in section 8.5.

DOE performed the calculations discussed herein using a software model, outputs are available at http://www.eere.energy.gov/buildings/appliance_standards/).

8.1.1 General Analysis Approach

Life-cycle cost is calculated using the following equation:

[a] For commercial and industrial equipment, the consumer is the business or other entity that pays for the equipment (directly or indirectly) and its energy costs.

$$LCC = TIC + \sum_{t=0}^{N-1} \frac{OC_t}{(1+r)^t}$$

Where:

LCC	=	life-cycle cost (in dollars),
TIC	=	total installed cost in dollars,
$\sum$	=	sum over the appliance lifetime, from year 1 to year N,
N	=	lifetime of the appliance in years,
OC	=	operating cost in dollars,
r	=	discount rate, and
t	=	year to which operating cost is discounted.

The payback period is the ratio of the increase in total installed cost (i.e., from a less energy efficient design to a more efficient design) to the decrease in annual operating expenditures. This type of calculation results in what is termed a simple payback period, because it does not take into account changes in energy expenses over time or the time value of money. That is, the calculation is done at an effective discount rate of zero percent. The equation for PBP is:

$$PBP = \frac{\Delta TIC}{\Delta OC}$$

Where:

ΔTIC	=	difference in total installed cost between a more energy efficient design and the baseline design, and
ΔOC	=	difference in annual operating expenses.

Payback periods are expressed in years. Payback periods greater than the life of the product indicate that the increased total installed cost is not recovered through reduced operating expenses.

Recognizing that inputs to the determination of consumer LCC and PBP may be either variable or uncertain, DOE conducts the LCC and PBP analysis by modeling both the uncertainty and variability of the inputs using Monte Carlo simulation and probability distributions for inputs. Appendix 8B provides a detailed explanation of Monte Carlo simulation and the use of probability distributions and discusses the tool used to incorporate these methods.

DOE calculates impacts relative to a case without amended or new energy conservation standards (referred to as the “no-new-standards case”). In the no-new-standards case, some consumers may purchase products with energy efficiency higher than a baseline model. For any given standard level under consideration, consumers expected to purchase a product with efficiency equal to or greater than the considered level in the no-new-standards case would be unaffected by that standard.

DOE calculates the LCC and PBP as if all consumers purchase a transformer in the expected initial year of compliance with a new or amended standard. At this time, the expected compliance date of potential energy conservation standards for 2027 manufactured in, or imported into, the United States is in 2027. Therefore, DOE conducted the LCC and PBP analysis assuming purchases take place in 2027.

8.1.2 No-new Standards Case

In developing appliance standards, DOE used the existing standard under Title 10 of the Code of Federal Regulations, Part 431 (10 CFR Part 431) as a baseline from which it calculates the impact of any efficiency level. This approach focused on the mix of selection criteria that customers are known to use when purchasing a distribution transformer. 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 transformer to purchase.[1,2]

To establish the no-new standards case for the LCC, DOE used distributions of efficiencies and an estimated percent of distribution 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 Modeling Distribution Transformer Purchase Decision

The LCC model uses a purchase-decision model that specifies which of the hundreds of designs in the engineering database designed to meet a given efficiency level that are likely to be selected by distribution transformer purchasers. The engineering analysis yielded a cost-efficiency relationship in the form of manufacturer selling prices, no-load losses, and load losses for a wide range of distribution transformer designs and costs. This set of data provides the LCC model with a distribution of distribution transformer design choices.

DOE used an approach that focuses on the selection criteria customers are known to use when purchasing distribution transformers. Those criteria include first costs, as well as the TOC method. The TOC method combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have historically used the TOC method to determine which distribution transformers to purchase.

The utility industry developed TOC evaluation as a tool to reflect the unique financial environment faced by each distribution transformer purchaser. To express variation in such factors as the cost of electric energy, and capacity and financing costs, the utility industry developed a range of evaluation factors: A and B values, to use in their calculations. A and B are the equivalent first costs of the no-load and load losses (in $/watt), respectively.

DOE used TOC evaluation rates as follows: 10 percent of liquid-immersed transformers were evaluated, 0 (zero) percent of low-voltage dry-type transformers were evaluated, and 0 (zero) percent of medium-voltage dry-type transformers were evaluated. DOE assumed purchases that were not made based on TOC were made on a lowest-first-cost decision. In addition to price, there are other details contributing to a "lowest-first-cost" purchase decision. Recognizing that prices vary slightly by order and customer for minor reasons, such as enclosure details, branding, or differences in competitive pricing, the analysis includes a uniform ±5 percent modifier to the MSPs developed in the engineering analysis.

After assigning an economic value to the A and B parameters of distribution transformer losses, purchasers add those costs to the first cost of acquiring the transformer in order to estimate the TOC. Throughout the LCC analysis, DOE expresses monetary values in units of real dollars (2020$).

The equation for calculating transformer TOC is:

$$TOC = FC + (A \times NLL) + (B \times LL).$$

Where:

FC	=	first cost of acquiring the distribution transformer, including purchase price and installation cost (2020$);
A	=	the no-load loss valuation parameter in dollars per watt ($/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).

Consumers of distribution transformer who utilize the TOC methodology will likely purchase make a purchase above the efficiency level. For those consumers who purchase based on first cost, the LCC will select the design from engineering analysis of lowest first cost regardless of efficiency, design, or any other consideration. Figure 8.1.1 and Figure 8.1.2 have dotted lines running horizontally through the engineering design space representing RU4, these lines represent the minimum and maximum first costs limits of the LCC. In this example we can see that the lowest cost designs near EL 4 will be selected in the no-new standards case, as well as for all ELs lower than 5 due to their low cost.

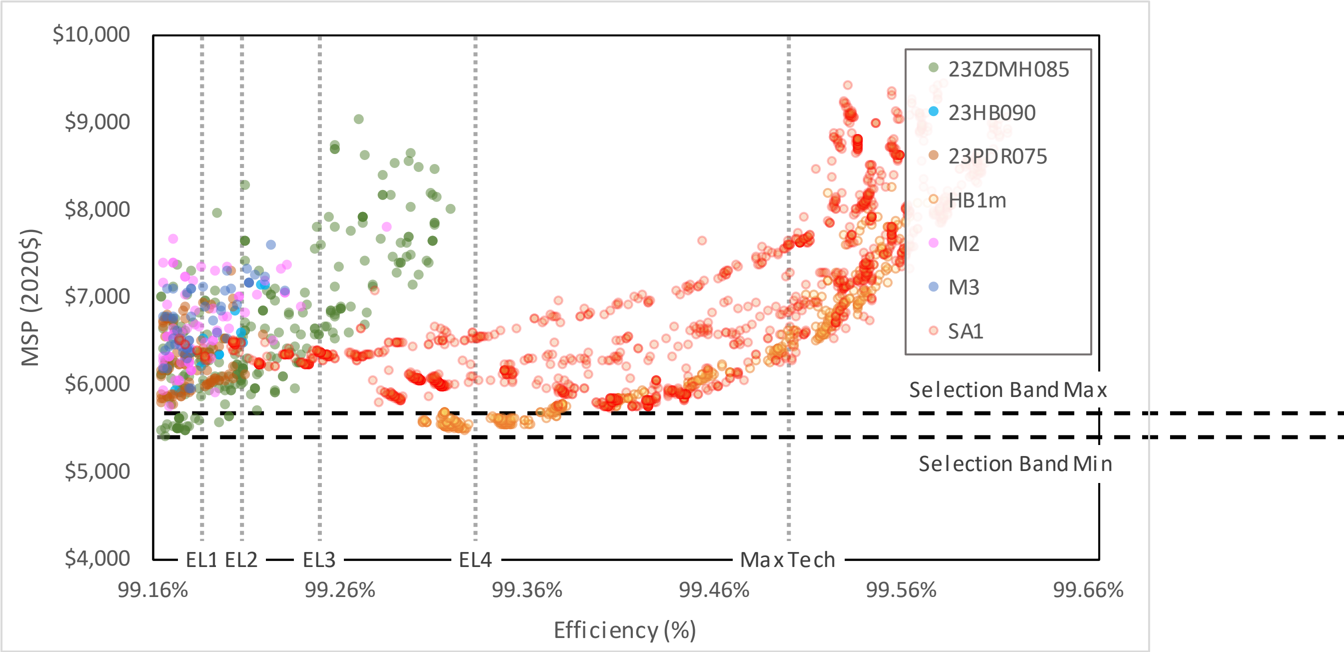


Figure 8.1.1 Lowest First Cost Designs Selected by the LCC in the No-new Standards Case for Rep Unit 4

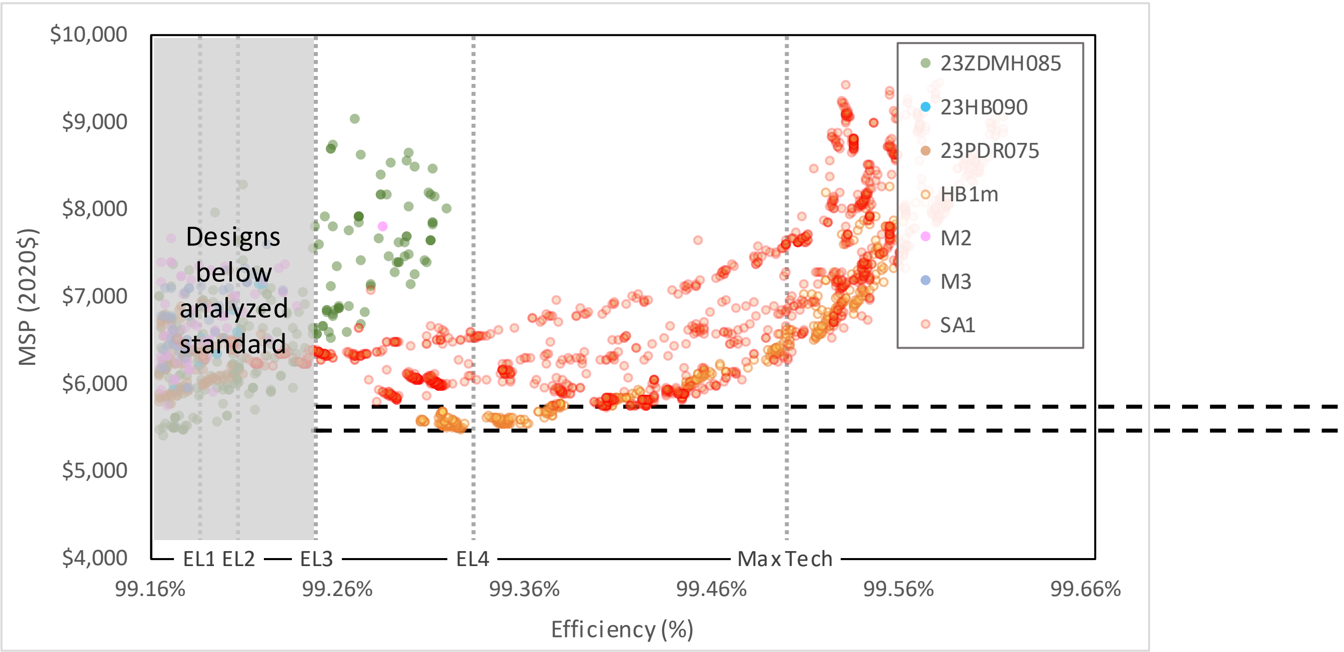


Figure 8.1.2 Lowest First Cost Designs Selected by the LCC in the Standard Level 3 for Rep Unit 4

8.1.3 Efficiency Levels

DOE conducted the LCC analysis for up to five energy efficiency levels (EL) for each of the 14 representative units defined in chapter 5, shown in Table 8.1.1. DOE selected the ELs as a function of percent loss reduction over baseline. Table 8.1.1 shows the percent loss reduction by transformer type.

Table 8.1.1 Efficiency Levels, Expressed as Percent Reduction in Losses from Baseline

Rep. Unit	EL 0	EL 1	EL 2	EL 3	EL 4	EL 5
1	0.0	1.0	2.0	15.0	25.0	40.0
2	0.0	1.0	2.0	10.0	25.0	40.0
3	0.0	3.0	6.0	12.0	25.0	40.0
4	0.0	3.0	5.0	10.0	25.0	40.0
5	0.0	3.0	5.0	10.0	25.0	40.0
6	0.0	1.0	5.0	10.0	15.0	20.0
7	0.0	2.5	5.0	10.0	15.0	20.0
8	0.0	2.5	5.0	10.0	15.0	20.0
9	0.0	5.0	10.0	15.0	30.0	50.0
10	0.0	5.0	10.0	15.0	30.0	50.0
11	0.0	5.0	10.0	15.0	30.0	50.0
12	0.0	5.0	10.0	15.0	30.0	50.0
13	0.0	5.0	10.0	15.0	30.0	50.0
14	0.0	5.0	10.0	15.0	30.0	50.0

Table 8.1.2 Efficiency Levels (%)

Rep. Unit	Current Standard	EL 1	EL 2	EL 3	EL 4	EL 5
1	99.11	99.12	99.13	99.24	99.33	99.46
2	98.95	98.96	98.97	99.05	99.21	99.37
3	99.49	99.51	99.52	99.55	99.62	99.69
4	99.16	99.18	99.20	99.24	99.37	99.49
5	99.48	99.50	99.51	99.53	99.61	99.69
6	98.00	98.02	98.10	98.20	98.29	98.39
7	98.60	98.63	98.67	98.74	98.81	98.88
8	99.02	99.04	99.07	99.12	99.17	99.21
9	98.93	98.98	99.04	99.09	99.25	99.46
10	99.37	99.40	99.43	99.46	99.56	99.68
11	98.81	98.87	98.93	98.99	99.16	99.40
12	99.30	99.33	99.37	99.40	99.51	99.65
13	98.69	98.75	98.82	98.88	99.08	99.34
14	99.28	99.32	99.35	99.39	99.49	99.64

8.1.4 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 2023, so the new standard will take effect in 2027. 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 2020$.

8.2 TOTAL INSTALLED COST INPUTS

8.2.1 Manufacturer Costs

Establishing a relationship between cost and efficiency is an integral part of DOE's rulemaking process. For distribution transformers, DOE derived this relationship from a database developed during the engineering analysis (chapter 5 of the TSD) of selling prices, no-load losses, and load losses for the range of distribution transformer designs contained in the LCC model. 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.

8.2.2 Overall Markup

For a given distribution channel, the overall markup is the value determined by multiplying all the associated markups and the applicable sales tax together to arrive at a single overall distribution chain markup value. Because there are baseline and incremental markups associated with the various market participants, the overall markup is also divided into a baseline markup (*i.e.*, a markup used to convert the baseline manufacturer price into a consumer price) and an incremental markup (*i.e.*, a markup used to convert a standard-compliant manufacturer cost increase due to an efficiency increase into an incremental consumer price). Refer to chapter 6 of this TSD for details.

8.2.3 Total Owning Cost: A and B Parameter Models

The *A* and *B* distribution 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 distribution 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 distribution transformers, DOE assumed a default evaluation rate of 0 (zero) percent.

DOE estimated the mean value of A for evaluators from public transformer purchase bids available on the Internet.[2,3,4,5,6,7,8,9,10] 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 distribution 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 distribution 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).

DOE collected A and B parameter values from distribution 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 2020$ using the U.S. Bureau of Labor Statistics' Producer Price Index for power generation, transmission, and control.[11]

8.2.3.1 A Parameter Model

To model the distribution of A values in the data, DOE developed a piecewise linear fit to the empirical distribution. Figure 8.2.1 shows the cumulative distribution function for both the data and the model.

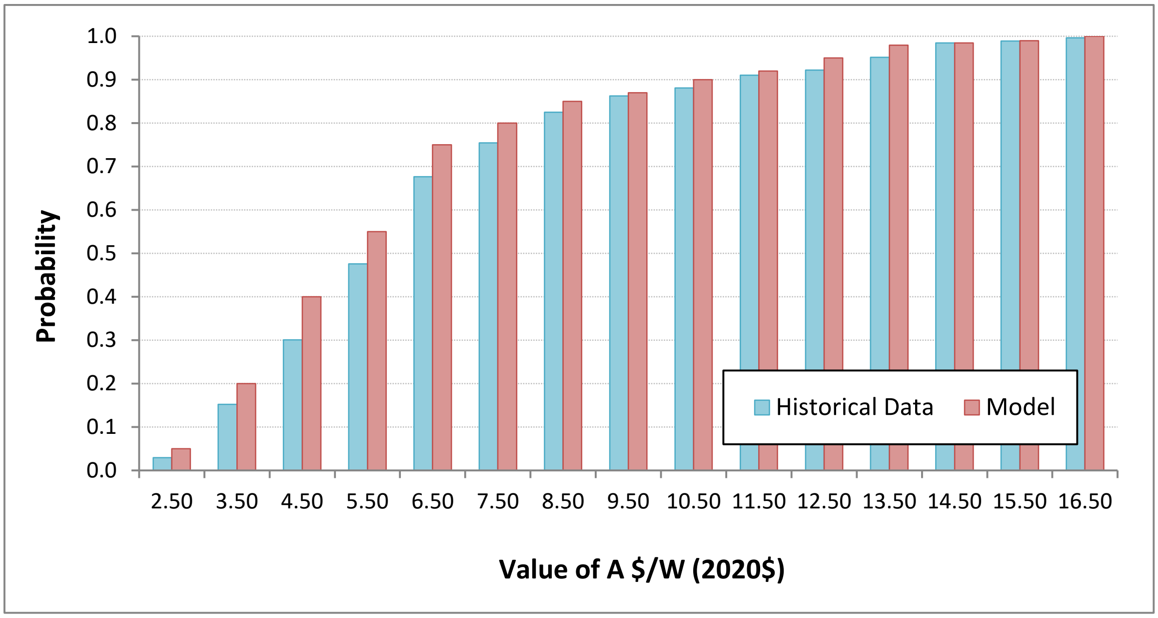


Figure 8.2.1 Cumulative Distribution of Historical A Parameter and Model A Parameter

Table 8.2.1 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 8.2.1 A Parameter Model and Historical Data

A Parameter Midpoint (*$/W*)	Cumulative Probability, Model (*%*)	Cumulative Probability, Historical Data (*%*)
2.5	0.05	0.03
3.5	0.20	0.15
4.5	0.40	0.30
5.5	0.55	0.48
6.5	0.75	0.68
7.5	0.80	0.75
8.5	0.85	0.83
9.5	0.87	0.86
10.5	0.90	0.88
11.5	0.92	0.91
12.5	0.95	0.92
13.5	0.98	0.95
14.5	0.99	0.99
15.5	0.99	0.99
16.5	1.00	1.00

8.2.3.2 B Parameter Model

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 (in blue), consisting of approximately 35 percent of the sample, has a B:A ratio of 0.27 and represents utilities that place relatively low economic value on load losses. The second cluster has a B:A ratio of 0.54 and represents utilities that place relatively higher economic value on load losses. Figure 8.2.2 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.

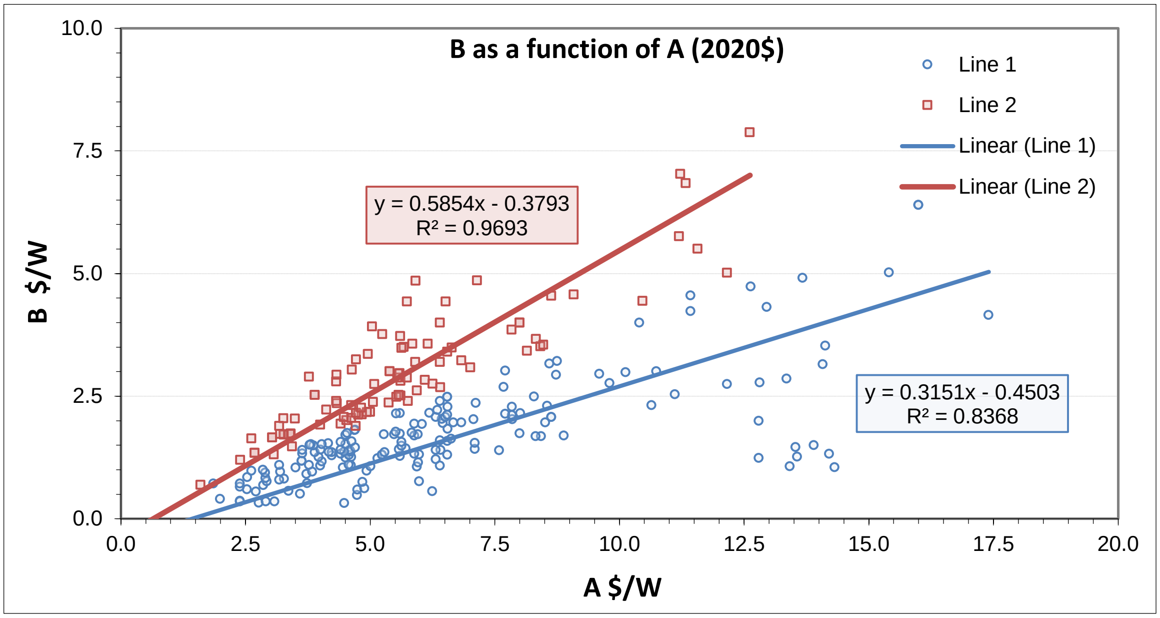


Figure 8.2.2 Distributions of Load Loss (B) Values versus No- Load Loss (A) Values for Liquid-Immersed Distribution Transformers

8.2.4 Installation Costs

Installation cost includes labor, overhead, and any miscellaneous materials and parts needed to install the equipment. In order to estimate the installed price for distribution transformers, DOE applied the following equation that describes the steps in the distribution channel for transformers:

$$Installed\ Price = M_{tax} \times \{M_{Mat} \times [M_{Dist} \times ManPrice]\} + M_L \times L$$

Where:

Installed_Price	=	the final installed price of the transformer (2020$),
M_{tax}	=	the factor that accounts for sales tax, estimated to be 1.069,[3]
M_L	=	the factor that accounts for the markup on direct installation labor costs,
L	=	the direct labor costs as a function of transformer weight (2018$), adjusted to 2020$ 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 (2020$).

DOE estimated markups for distribution transformers by fitting a linear cost function to the *RS Means* electrical cost data (see chapter 6). 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 (1) bare material cost plus 10 percent for profit, (2) bare labor cost plus total overhead and profit.

8.2.5 Impact of Increased Distribution Transformer Weight on Installation Costs

DOE derived the weight-versus-capacity relationship for a typical distribution transformer from the design data produced by the engineering analysis in the TSD. 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 (pounds),
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:

$$L = 35.103 \times Weight^{0.5644}$$

Where:

L	=	the installation, direct labor, and equipment costs (2019$),
$Weight$	=	the weight of the transformer (pounds).

Total installation costs can depend on the size and weight of the equipment. In the June 2019 Early Assessment RFI, DOE requested information and data related to how installation cost changes as a function of distribution transformer size and weight for various types and capacities of distribution transformers. 84 FR 28239, 28254. For this analysis, as discussed in the following paragraphs, DOE reevaluated the methods it used in the April 2013 Standards Final Rule.

Higher efficiency distribution transformers may be larger and heavier than less efficient distribution transformers, with the degree of weight increase depending on how a distribution transformer’s design is modified to improve efficiency. In the April 2013 Standards Final Rule, DOE estimated the increased cost of installing larger, heavier distribution transformers based on estimates of labor cost by distribution transformer capacity from Electrical Cost Data Book, by *RS Means*. For the current analysis DOE retained certain portions of the prior approach where installation costs are based on the weight of the transformer for dry-type transformers and updated its installation cost methodology for liquid-immersed transformers based on new findings described below.

For this analysis DOE reexamined the cost impacts of making like-for-like, in terms of transformer distribution transformer replacement into, and onto, existing utility structures. DOE surveyed several electric utilities through an engineering firm (SME) to inquire about their installation procedures and remediation practices for when a new, potentially larger or heavier distribution transformer of the same capacity (in kVA) could not be installed in the desired location.[b]

The weights for the distribution transformers covered under the scope of this analysis range in weight from 450 pounds to over 15,000 pounds. DOE's SME found that distribution transformers are almost exclusively moved into place using mechanical equipment, for example bucket trucks, cranes, forklifts, pallet jacks, and/or hoists. Unless the change in distribution transformer weight is greater than the maximum safe operating limits of the mechanical equipment required for installation (meaning that mechanical equipment of greater capabilities would be needed) the same costs associated with the mechanical equipment and crew can be used for the no-new standards and standards cases. The highly mechanized procedures for the installation of distribution transformer results in a circumstance where there would be very little, if any, difference in cost between the no-new standards, and potential amended standards cases. To reflect this, DOE has applied the following installation costs as a function of transformer weight shown in Table 8.2.2. DOE assumed that a higher fraction to dry-type transformers installations would be impacted by transformer weigh because they are installed indoors, where there may be limitations on the types of mechanical rigging devises that can be applied.

Table 8.2.2 Applied Weight Based Installation Costs

Transformer Type	Fraction with Weight Based Installation Costs (%)
Liquid-immersed	95
Low-voltage Dry-type	50
Medium-voltage Dry-type	50

8.2.5.1 Pad Installations

Pad-mounted distribution transformers are typically installed on prefabricated concrete pads of different dimensions which are dependent on the footprint area of the to-be-installed new distribution transformer. Responses to DOE's survey regarding installation indicate that the increasing footprint of a replacement distribution transformer could be an issue in the future, and that while current designs are near the limits of existing installation sites, increasing footprint dimensions have not been an issue to date. Further, responses were mixed as to whether the radiators on larger capacity pad-mounted distribution transformers had to be contained within the

[b] See appendix 8D of the TSD for details.

footprint of the supporting concrete pad, or if they could overhang the footprint of the concrete pad. Further, respondents also stated that these circumstances can be avoided with proper specification of distribution transformer dimensions when making purchases. For this analysis, DOE did not include additional installation cost for pad replacement as these costs can likely be avoided by customers specifying the dimensions of replacement distribution transformers to fit within a customer's area constraints.

8.2.5.2 Overhead Installations

In the June 2019 Early Assessment RFI, DOE stated that it is considering including costs to account for the rare occasion that a more efficient, pole-mounted replacement distribution transformer would require the installation of a new, higher-grade (greater strength), utility pole to support an increase in weight due to increased distribution transformer efficiency. 84 FR 28239, 28254-28255. DOE requested comment on its method for accounting for pole replacement, its understanding of pole upgrades because of increased distribution transformer efficiency and weight, and any other factors to consider. *Id.*

When evaluating the impacts of replacing existing pole-mounted distribution transformers, DOE assumes that the replacement equipment provides the same utility as the original equipment, *i.e.*, the replacement distribution transformer provides the same capacity (in terms of kVA), service provided, and number of phases.

In evaluating replacement of pole-mounted distribution transformers, DOE considers whether such replacement would result in pole overloading and therefore require a replacement of the pole. In general, factors for determining whether pole overloading would be an issue depend in part on the application of the pole. If the pole is installed along a feeder line with distribution lines extending tangentially out from the pole, this will be characterized by a reduction in wind span to below safe limits due to increased transformer weight results in overloading.[c] If the pole is installed at the end of a line, and is guyed in place, it is considered a dead-end structure, and the pole must support the weight of the distribution transformer and connected lines; pole overloading occurs when the minimum lead guy length for that pole exceeds safe limits.

Other factors must be considered to determine if pole overloading would occur, such as the capacity, number, shape, weight, and dimensions of distribution transformer(s) being replaced; class and height of pole on which the distribution transformers are to be mounted; where on the pole the distribution transformer(s) is to be mounted; what primary and secondary

[c] Allowable wind span refers to the horizontal distance between the mid-span points of adjacent spans; in this case the length of horizontal conductor between two poles, measured at the mid-points.

conductors are attached to the pole; the quantity, type and where these conductors are mounted; how many underbuilds, their diameters, and where on the pole they are mounted; what is the required grade of construction; the exiting wind span on the section of feeder line, or maximum shortest guy requirements of the original dead-ended pole; and in which climate loading zone (either NESC or GO95) the poles in question are located.[d,e, f]

DOE notes that wooden poles have finite lifespans and need to be periodically replaced due to decay or other reasons, such as line upgrades; physical damage from wind, ice, or cars; ground shifting; *etc*. There will be a segment of any pole population at, or near, the end of its safe operating lifetime due to age and operational life cycle. In these circumstances each utility must evaluate the safety of its pole/structure before installing replacement equipment. In certain cases, the replacement of a pole may be needed independent of the characteristics of a replacement distribution transformer. DOE does not consider the cost of replacing the pole to maintain safe operations to be an additional burden to a consumer if this occurrence is needed in the absence of any potential revised standard as these costs are not related to increased distribution transformer efficiency.

To assist with its modeling of the potential of pole overloading due to increased distribution transformer weight, DOE commissioned a methodological report and model from Line Design University.[g] The report and model are available for review in appendix 8D of this TSD.

To better understand the potential impacts of transformer weight on overhead structures, DOE conducted several scenario analyses for given installations.

DOE examined the impacts on allowable wind spans for a bank of 3, single-phase, 167 kVA distribution transformers serving loads in a densely populated area in a NESC Heavy Loading District—Combined Wind and Ice with the following parameters.

- Grade B construction

---

[d] The National Electrical Safety Code® (NESC®). NESC governs the United States standard of the safe installation, operation, and maintenance of electric power and utility systems overhead lines in addition to other topics. For more information see: https://standards.ieee.org/products-services/nesc/index.html
[e] General Order 95 (GO95). GO95 governs, for the state of California, uniform requirements for overhead electrical line construction, and to secure safety to persons engaged in the construction, maintenance, operation or use of overhead electrical lines and to the public in general. For more information see: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M217/K418/217418779.pdf
[f] Both NESC and GO95 divide the Nation, and California in the case of GO95, into regions that experience climatic conditions that add physical stressors, such as wind and ice, on utility structures. NESC divides the Nation into heavy, medium, and light regions, while GO95 divides California into heavy and light regions. In both cases, the region effects the input assumptions for calculating utility structure strength, and their resistance to loads.
[g] See: https://www.linedesignuniversity.com/

- Conductors: 3 Æ 4/O ACSR (6/1) conductors
- 4-inch telecommunication – underbuilt.
- NESC Heavy Loading District – Combined Wind and Ice
- Pole: Class 1 — 40 feet (36 feet above ground)

For this scenario DOE considered wind spans between 100 and 150 feet to be typical for densely populated areas. Further, as DOE did not explicitly model a 167 kVA distribution transformer as part of its engineering analysis DOE estimated the weights in the no-new standards and at max-tech (EL 5), the heaviest designs, by scaling the representative unit 2, a 25 kVA round tank; these resulted in a per distribution transformer weight ranging from 1,870 pounds in the no-new standards case to 3,270 pounds in the max-tech case. DOE found that the increase in transformer weight reduced the allowable wind span from 236 to 193 feet. At the maximum analyzed efficiency in the max-tech case DOE found that the reduced allowable wind span was still greater than the greater assumed typical allowable wind span of 150 feet, and that no replacement pole would be needed. DOE agrees with Howard that to the extent that larger distribution transformers are banked, installation issues may arise; however, without data as to when and how often such installation circumstances occur, DOE is limited in its ability to model such impacts.

To examine potential impacts to smaller utilities with fewer customers per transformer DOE analyzed the following pole loading scenarios characterized by the average basecase distribution transformer versus the average max-tech (amorphous) distribution transformers examined in this analysis. DOE examined the increase in distribution transformer weight for a 25 kVA, as it is the most typical pole-mounted distribution transformer, with the following installation criteria:

- Grade B construction
- Conductors: 1Æ, and 3 Æ 4/O ACSR (6/1)
- NESC Heavy Loading District – Combined Wind and Ice
- Pole height: 40 feet (36 feet above ground)

For these scenarios DOE considers the following wind spans in Table 8.2.3 to be typical for rural or low population areas where efforts are made to serve customers with the fewest structures while maintaining the minimum clearances dictated by NESC or GO95.

Table 8.2.3 Assumed Typical Wind spans by NESC Loading District for Rural Areas

NESC Loading District	Minimum Wind span (feet)	Maximum Wind span (feet)
Heavy	250	275
Medium	275	325
Light	325	375

The first scenario examines upgrading a single, 25 kVA distribution transformer with a basecase weight of 450 pounds to a replacement distribution transformer at the max-tech standards case, with a weight of 787 pounds. This scenario assumed single-phase conductors, a class 4 pole, and no underbuilds. DOE found the allowable wind span was reduced from 422 to 409 feet, a distance well above the minimum wind span in Heavy Loading Districts of 250 feet.

DOE then evaluated the same distribution transformer when installed with three-phase conductors on a class 3 pole. DOE found the wind span would be reduced from 294 to 286 feet, again, a distance greater than 250 feet minimum allowable wind span of the Heavy Loading Districts.

Given the above scenarios, DOE finds that the increase in weight in the standards case results in small reductions in allowable wind span. As a result, DOE has not included pole replacement in this analysis.

8.2.5.3 Vault (Underground) and Subsurface (at Grade) Installations

In the context of this analysis, DOE uses the term "vault distribution transformer" to mean a distribution transformer specifically designed for and installed in an underground, below-grade, vault. DOE understands that these distribution transformers represent less than 2 percent of units shipped; and are typically owned and operated by utilities serving urban populations. These vaults are typically underground concrete rooms with an access opening in the ceiling through which the transformer can be lowered for installation or replacement. Because the consumers who purchase vault or subsurface transformers might be disproportionally adversely affected by a potential change in the energy efficiency standards, DOE will examine the consumer impacts of vault and subsurface with a separate life-cycle cost subgroup analysis as part of the NOPR.

8.2.6 Application of Learning Rate for Equipment Prices

Examination of historical price data for certain appliances and equipment that have been subject to energy conservation standards indicates that an assumption of constant real prices may, in many cases, overestimate long-term trends in appliance and equipment prices. Economic literature and historical data suggest that the real costs of these products may, in fact, trend downward over time according to "learning" or "experience" curves. Desroches *et al*. (2013) summarizes the data and literature that is relevant to price projections for selected appliances and equipment.[3] The extensive literature on the "learning" or "experience" curve phenomenon is typically based on observations in the manufacturing sector.[h]

In the experience curve method, the real cost of production is related to the cumulative production or "experience" with a manufactured product. This experience is usually measured in terms of cumulative production. A common functional relationship used to model the evolution of production costs in this case is:

$$Y = a\,X^{(-b)}$$

Where:

a =	an initial price (or cost),
b =	a positive constant known as the learning rate parameter,
X =	cumulative production, and
Y =	the price as a function of cumulative production.

As experience (production) accumulates, the cost of producing the next unit decreases. The percentage reduction in cost that occurs with each doubling of cumulative production is known as the learning rate (LR), which is given by:

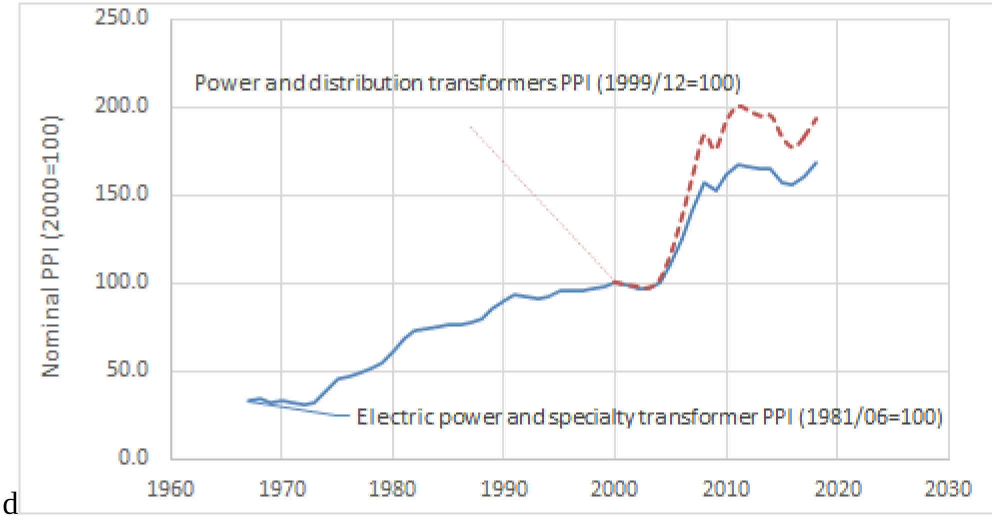
$$LR = 1 - 2^{(-b)}$$

In typical learning curve formulations, the learning rate parameter is derived using two historical data series: cumulative production and price (or cost).

To derive a learning rate parameter for distribution transformers, DOE used historical Producer Price Index (PPI) data for Electric power and specialty transformer PPI (PCU335311335311) and Power and distribution transformers PPI (PCU3353113353111). Inflation-adjusted price indices were calculated by dividing the PPI series by the implicit Gross Domestic Product price deflator for the same years. The inflation-adjusted price index is shown in Figure 8.2.3, with the deflated index shown in Figure 8.2.4.

---

[h] In addition to Desroches (2013), see Weiss, M., Junginger, H.M., Patel, M.K., Blok, K., (2010a). A Review of Experience Curve Analyses for Energy Demand Technologies. Technological Forecasting & Social Change. 77:411-428.



d

Figure 8.2.3 Nominal Electric power and specialty transformer (PCU335311335311) and Power and distribution transformers (PCU3353113353111). PPI from 1967 to 2018

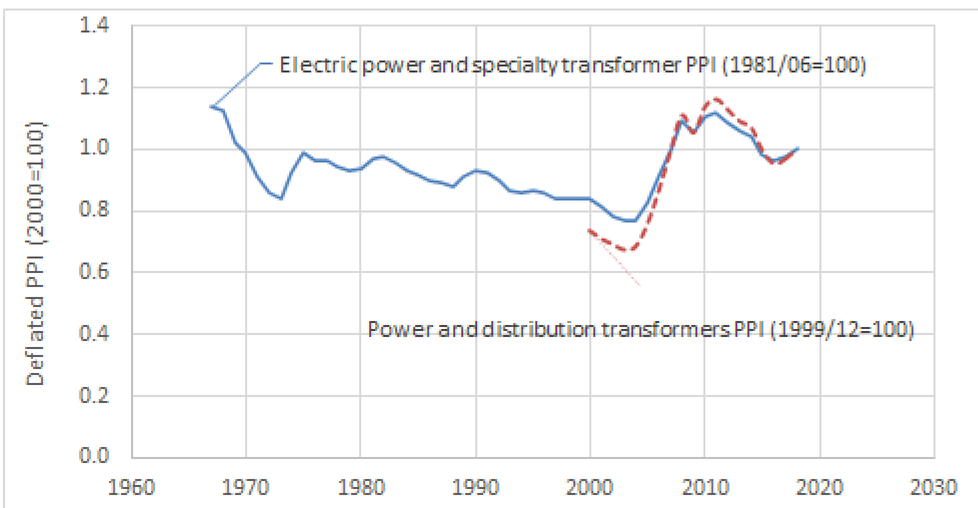


Figure 8.2.4 Deflated Electric power and specialty transformer (PCU335311335311) and Power and distribution transformers (PCU3353113353111). PPI from 1967 to 2018

From the mid-1970s to 2005, the deflated price index for transformers was in decline. Since then, the index has risen sharply then continues its downward trend. DOE performed an exponential fit on the deflated price index for transformers.

Given the above considerations, DOE decided to use a constant price assumption as the default price factor index to project future distribution transformer prices in 2026. Thus, prices forecast for the LCC and PBP analysis are equal to the values from the engineering analysis (chapter 5) for each efficiency level in each equipment class.

8.2.7 Total Installed Cost

The total installed cost is the sum of the consumer product cost and installation cost. The total installed costs for each distribution transformer representative unit at each candidate standard level considered are shown in the tables in section 8.5.

8.3 OPERATING COST INPUTS

8.3.1 Annual Energy Consumption

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.

8.3.1.1 Loading Levels for Utilities Serving Low Population Densities

DOE recognizes that rural areas the number of customers per distribution transformer is likely to be significantly lower than in urban or suburban areas, which in turn may 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 rep units 1 through 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. In the 2013 ECS final rule, DOE assumed that for those utilities serving primarily low density residential areas the median of the RMS load distribution is reduced from 35 percent by 25 percent. DOE plans to examine these impacts as a separate subgroups analysis in the NOPR.

8.3.1.2 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.

8.3.1.3 Trends in Load Growth

The LCC analysis examines a cross-section of distribution 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 percent for liquid-immersed and no growth trend for dry-type distribution transformers.

8.3.2 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 distribution transformers, which are owned predominantly by utilities that pay costs that vary by the hour. DOE used the monthly analysis for dry-type distribution transformers, which typically are owned by C&I establishments that receive monthly electricity bills.

8.3.2.1 Hourly Marginal Electricity Price Model for Liquid-Immersed Distribution Transformers

To evaluate the electricity costs associated with liquid-immersed distribution 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.

Capacity Costs

DOE developed a methodology 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).[14] The method depends on the type of generation that is built, DOE developed the same capacity costs formula for both types of losses.

Foregone capacity costs, CC, are defined as follows:

$$CC_{LL} = \Delta P_{LL}\left(\beta C_M\left(CC_{adj}\left(C_{G,LL}F_G + C_T F_T\right) + F_{OM,LL}\right) - R_{C,LL}\right)$$

$$CC_{NLL} = \Delta P_{NLL}\left(\beta C_M\left(CC_{adj}\left(C_{G,NLL}F_G + C_T F_T\right) + F_{OM,NLL}\right) - R_{C,NLL}\right)$$

$$CC = CC_{LL} + CC_{NLL}$$

Where:

LL, NLL = subscripts for load loss and no-load loss, respectively;

ΔP = the reduction in system peak load;

β = a load adjustment factor, which is one plus the estimated system losses;

C_M = the reserve capacity margin;

CC_{adj} = a capacity construction cost adjustment factor, which accounts for variation in construction costs by region,

C_G = the overnight cost in \$/kW of building new generation capacity;

F_G = the fixed charge rate, used to convert the overnight cost to an annual carrying cost;

C_T = the overnight cost in \$/kW of new transmission capacity;

F_T = the fixed charge rate for transmission investments;

F_{OM} = the fixed operations and maintenance cost for new capacity in \$/kW

R_{CV} = the residual capacity value; this is the amount of annual revenue a generator is expected to earn when market prices or system lambdas are above the operating cost of that unit, expressed in $/kW

DOE calculated the various inputs of this equation as follows.

Peak Load Reduction (ΔP): This reduction results from improved transformer efficiency. As certain input parameters are dependent on the type of load, the reduction in peak capacity requirement is observed through its no-load loss and load loss components. DOE used a statistical model to estimate the reduction in load loss coincident with the system load peak, consistent with the methodology used to model transformer hourly loads.

Loss Adjustment Factor (β): The loss adjustment factor represents the fraction of electricity that is dissipated by the transmission and distribution system. It is equal to one plus the fractional losses in the system. DOE used the regional transmission and distribution loss factors from the NEMS planning model[2], given in Table 8.3.2.

Capacity Margin (C_M): This factor represents the fraction of planning reserve capacity needed to ensure system reliability, per unit of additional capacity requirement. DOE assumed the industry standard of 15 percent.

Capacity Construction Cost Adjustment Factor (CC_{adj}): These factors account for the fact that construction costs vary by region. They are applied to the overnight cost of new generation to estimate the cost of constructing new power plants by NEMS region. The factors were developed using representative costs of labor, materials and equipment by the U.S. Army Corps of Engineers Civil Works Construction Cost Index System.[15] The regional capacity construction cost adjustment factors are given in Table 8.3.2.

Unit Generation Capacity Cost (C_G): This factor represents the overnight cost of building new generating capacity, as provided by NEMS.[14] Table 8.3.2 shows the rates for generating no-load loss and load loss capacity for regulated chosen peak and base load systems.

Generation Fixed Charge Rate (F_G): A fixed charge rate is used to convert the overnight capital cost of new generation to an annualized (or amortized) cost. Table 8.3.1 shows the F_G for each of the average discount rate and plus/minus two standard deviation scenarios for the investor owned utilities (IOUs) and publicly owned utilities (POUs).

Table 8.3.1 Generation Fixed Charge Rates

	IOU			POU		
	Average Case	- 2 S.D.	+ 2 S.D.	Average Case	- 2 S.D.	+ 2 S.D.
Fixed Charge Rate	0.131	0.113	0.149	0.095	0.077	0.114
System Design						
Installed System Cost per kW	$1,300	$1,300	$1,300	$1,300	$1,300	$1,300
Plant Cost						
O&M Costs ($/kW)	$8	$8	$8	$8	$8	$8
O&M Costs Escalator (%/yr)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Financing						
Financing Lifetime (years)	20	20	20	20	20	20
% Equity Financed	50%	50%	50%	0%	0%	0%
% Debt Financed	50%	50%	50%	100%	100%	100%
Debt Interest rate	5.96%	3.34%	8.58%	5.96%	3.34%	8.58%
Cost of Equity	10.51%	9.07%	11.95%	10.51%	9.07%	11.95%
Pre-tax WACC	8.23%	6.20%	10.26%	5.96%	3.34%	8.58%
After tax WACC	7.05%	5.54%	8.57%	5.96%	3.34%	8.58%
Tax Assumptions						
Federal Tax Rate	35.00%	35.00%	35.00%	0.00%	0.00%	0.00%
State Tax Rate	7.00%	7.00%	7.00%	0.00%	0.00%	0.00%

DOE select a F_G consistent with the discount rates described in section 8.3.3. As shown in Figure 8.3.1, the relationship between the real weighted-average cost of capital (WACC) and F_G is nearly linear:

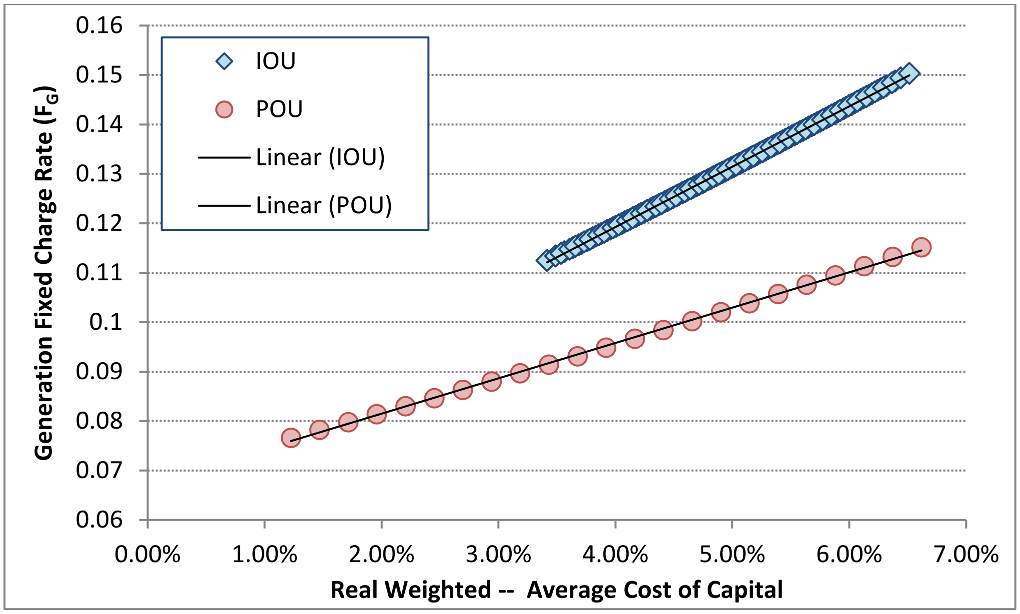


Figure 8.3.1 Real Weighted-Average Cost of Capital and Generation Fixed Charge Rate

Given this relationship, the appropriate F_G rates can be closely estimated using the following equations:

$$F_G \text{ for IOUs} = 1.122 \times \text{Real Discount Rate} + 0.070, \text{ and}$$

$$F_G \text{ for POUs} = 0.715 \times \text{Real Discount Rate} + 0.0672$$

By applying these equations for each of the discount rates for IOUs and POUs ensures that the discount rate and F_G are properly aligned. Based on the analysis, DOE applied a value of 0.11 in the calculations.

Unit Transmission Capacity Cost (C_T): This overnight cost per unit for an increment of new transmission capacity is provided by NEMS.[15] The values are provided per EMM region in Table 8.3.2.

Transmission Fixed Charge Rate (F_T): The fixed charge rate is used to convert the overnight cost of new investment in transmission into an annual (amortized) cost. DOE used a value of 0.12.[14]

Residual Capacity Value (R_{CV}): The residual capacity value represents the additional revenue a generation owner would earn whenever their operating cost is below the market clearing price or system lambda. This annual revenue offsets, to some extent, the cost of building new generation capacity. The operating cost is estimated as the fuel cost times the heat rate plus the variable O&M. The residual capacity value is expressed in $/kW-year, and is calculated as follows:

1. In each hour, the difference between the operating cost and the hourly price is calculated; a small threshold of 3 percent is applied to the hourly price to ensure that the calculation is not overly sensitive to the hourly price
2. For peaking capacity, if the difference is above zero, then the unit is assumed to be dispatched and the revenues for that hour are added to the annual sum
3. For base-load capacity, if the difference is above zero during a period of 3 hours or more, the unit is assumed to be dispatched and the revenues for that period are added to the annual sum.

For both capacity types, it is assumed that the fuel used is natural gas. It is also assumed that the base load is covered by the multi-shaft natural gas combined-cycle, while the peak load is predominantly provided by the equivalent single-shaft plants.

Wholesale electricity prices were scaled from the 2020 data year to the calculation year using the generation price trend in *AEO 2021*. The natural gas fuel price for electric power generation was taken from *AEO 2021*.

For a natural gas combustion turbine, the R_{CV} is equal to 27 $/kW in 2016 and 21 $/kW in 2035. An average of 25 $/kW is used to represent a typical annual value for both peaking and base load plants.

Fixed operations and maintenance cost (F_{OM}) was taken from AEO 2020, and equals 14.04 $/kW for single and 12.15 $/kW for multi-shaft plants, that is for load and no-load loss, respectively.

Table 8.3.2 Regional Capacity Cost Factors and Overnight Costs

EMM Region[i]		Construction cost adjustment factor, CC_{adj}	Loss adjustment factor, β	Unit Generation Capacity Cost, C_G		Unit Transmission Capacity Cost, C_T
				NLL	LL	
Code	Name			(2020$/kW)		
1	TRE	0.87	1.06	848	974	171.86
2	FRCC	0.94	1.07	886	1011	171.86
3	MISW	1.06	1.07	1003	1125	162.61
4	MISC	1.06	1.07	1004	1119	162.61
5	MISE	1.02	1.07	1030	1147	162.61
6	MISS	0.91	1.08	880	1003	171.86
7	ISNE	1.06	1.08	1131	1294	199.62
8	NYCW	1.10	1.07	1549	1717	199.62
9	NYUP	1.16	1.08	1112	1298	199.62
10	PJME	1.10	1.07	1137	1296	199.62
11	PJMW	1.02	1.07	931	1075	162.61
12	PJMC	1.06	1.07	1192	1299	162.61
13	PJMD	0.89	1.07	1051	1237	171.86
14	SRCA	0.89	1.07	869	991	171.86
15	SRSE	0.89	1.07	883	1003	171.86
16	SRCE	0.89	1.07	901	1023	167.23
17	SPPS	0.91	1.08	879	1001	171.86
18	SPPC	0.91	1.08	944	1063	171.86
19	SPPN	0.99	1.09	872	992	162.61
20	SRSG	0.97	1.09	839	975	298.77
21	CANO	1.18	1.09	1278	1451	428.33
22	CASO	1.18	1.09	1374	1202	428.33
23	NWPP	1.00	1.09	1135	985	342.40
24	RMRG	0.97	1.09	919	790	298.77
25	BASN	1.00	1.09	994	887	342.40

Hourly Energy Costs

DOE developed two sets of energy costs to be applied to the two types of losses:

[i] Regions are defined in the U.S. *Energy Information Administration* (*EIA*), National Energy Modeling System (NEMS) Electricity Market Module (EMM)

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:

$$EC_{NLL} = \beta \in_{NLL} \sum_h P(h),$$

and

$$EC_{LL} = \beta \in_{LL} \sum_h P(h) e^2(h).$$

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.[16] DOE used the most recent data available, from 2015, 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.

8.3.2.2 Monthly Marginal Electricity Price Model for Dry-Type Distribution Transformers

For C&I owners of dry-type distribution transformers, DOE developed average marginal electricity prices from an analysis of marginal energy prices from tariffs for commercial buildings.[17, 18]

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 levies 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.[j] Those monthly data were processed using Coughlin et al.'s tariff bill calculation tools[17] 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 2018. To convert to 2020 dollars, DOE used two datasets: (1) the report, *Average Regulated Retail Price of Electricity*[19] for 2004–2020, and (2) the Edison Electric Institute (EEI) *Typical Bills and Average Rate* reports for 2007[20] through 2020.[21,22] 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.[12] The EEI data only covers 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 8.3.3 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.

[j] See: Chapter 7, Energy Use and End-Use Load Characterization, for details regarding DOE's treatment of the CBECS sample.

Table 8.3.3 Average Seasonal Marginal Energy and Demand Prices by Census Division

Census Division	Marginal Energy Price *2020$/kWh*		Marginal Demand Price *2020$/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

8.3.2.3 Future Electricity Cost and Price Trends

For the relative change in electricity prices for future years, DOE used the price trends from the forecast scenarios in the EIA's *AEO 2021*.[23] The default price trend scenario that DOE used in the LCC analysis is the trend in the *AEO 2021* reference case. LCC model provides a sensitivity in appendix 8B with electricity price trends from the *AEO 2021* low-growth scenario, reference scenario, and high-growth scenario.

DOE used different projections AEO *2021* price projections. Because *AEO 2021* does not forecast beyond 2050, DOE extrapolated the values in later years as "flat" with no changes beyond 2050. For liquid-immersed distribution transformers, which are primarily owned by utilities, an average of the price trends of all sectors, weighted by each sector. For dry-type distribution transformers, which are primarily owned by commercial and industrial C&I building owners the price trend applied is the national average of the retail cost of electricity to C&I customers for all losses.

8.3.3 Discount Rates

DOE's method views the purchase of a higher efficiency appliance as an investment that yields a stream of energy cost savings. DOE derived the discount rates for the LCC analysis by estimating the cost of capital for companies or public entities that purchase distribution transformers. For private firms, the weighted average cost of capital (WACC) is commonly used to estimate the present value of cash flows to be derived from a typical company project or investment. Most companies use both debt and equity capital to fund investments, so their cost of capital is the weighted average of the cost to the firm of equity and debt financing, as estimated from financial data for publicly traded firms in the sectors that purchase distribution transformers.[k] As discount rates can differ across industries, DOE estimates separate discount rate distributions for a number of aggregate sectors with which elements of the LCC building sample can be associated.

Damodaran Online, the primary source of data for this analysis, is a widely used source of information about debt and equity financing for most types of firms.[l] The nearly 200 detailed industries included in the Damodaran Online data (see appendix 8E) were assigned to the aggregate sectors shown in Table 8.3.4, which also shows the mapping between the aggregate sectors and CBECS Principal Building Activities (PBAs).[m] Damodaran Online data for manufacturing and other similar industries were assigned to the aggregate Industrial sector, while data for farming and agriculture were assigned to the Agriculture sector. Public entities are included in the sectors Federal Government and State/Local Government, but Damodaran data are not used for these sectors.

---

[k] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporations Finance and the Theory of Investment," *American Economic Review* 48, no. 3 (1958): 261–297.
[l] Aswath Damodaran, "Data Page: Costs of Capital by Industry Sector," Damodaran Online, 2019, http://pages.stern.nyu.edu/~adamodar/.
[m] Previously, Damodaran Online provided firm-level data, but now only industry-level data is available, as compiled from individual firm data, for the period of 1998-2018. The data sets note the number of firms included in the industry average for each year.

Table 8.3.4 Mapping of Aggregate Sectors to CBECS Categories

Sector in DOE Analysis	Applied to CBECS PBAs (Name and PBA number)
Education[n]	Education (14)
Food Sales	Food sales (6)
Food Service	Food service (15)
Health Care	Outpatient health care (8); Inpatient health care (16); Nursing (17); Laboratory (4)
Lodging	Lodging (18)
Mercantile	Enclosed mall (24); Strip shopping mall (23); Retail other than mall (25)
Office	Office (2)
Public Assembly	Public assembly (13)
Service	Service (26)
All Commercial	All CBECS PBAs, including those specified above
Industrial	Not in CBECS
Agriculture	Not in CBECS
Federal Government	Not in CBECS
State/Local Government	Not in CBECS

Note: CBECS only includes buildings used by firms in "commercial" sectors, so Industrial, Agriculture, Federal Government, and State/Local Government have no associated PBA identifier. However, discount rate distributions are required for these sectors because they are significant consumers of some types of appliances and energy-consuming equipment.

For private firms, DOE estimated the cost of equity using the capital asset pricing model (CAPM).[o] CAPM assumes that the cost of equity (k_e) for a particular company is proportional to the systematic risk faced by that company, where high risk is associated with a high cost of equity and low risk is associated with a low cost of equity. In CAPM, the systematic risk facing a firm is determined by several variables: the risk coefficient of the firm (β), the expected return on risk-free assets (R_f), and the equity risk premium (*ERP*). The cost of equity can be estimated at the industry level by averaging across constituent firms. The risk coefficient of the firm indicates the risk associated with that firm relative to the price variability in the stock market. The expected return on risk-free assets is defined by the yield on long-term government bonds. The

[n] This sector applies to private education, while public education is covered under the later discussion of buildings operated by state and local government entities.
[o] Ibbotson Associates, "SBBI Edition 2009 Valuation Yearbook" (Chicago, IL, 2009), http://corporate.morningstar.com/ib/documents/MarketingOneSheets/DataPublication/SBBI_ValuationTOC.pdf.

ERP represents the difference between the expected stock market return and the risk-free rate. The cost of equity financing is estimated using the following equation, where the variables are defined as above:

$$k_{ei} = R_f + (\beta_i \times ERP)$$

Where:

k_{ei} = cost of equity for industry *i*,

R_f = expected return on risk-free assets,

β_i = risk coefficient of industry *i*, and

ERP = equity risk premium.

Several parameters of the cost of capital equations can vary substantially over time, and therefore the estimates can vary with the time period over which data is selected and the technical details of the data averaging method. For guidance on the time period for selecting and averaging data for key parameters and the averaging method, DOE used Federal Reserve methodologies for calculating these parameters. In its use of the CAPM, the Federal Reserve uses a forty-year period for calculating discount rate averages, utilizes the gross domestic product price deflator for estimating inflation, and considers the best method for determining the risk free rate as one where "the time horizon of the investor is matched with the term of the risk-free security."[p]

By taking a forty-year geometric average of Federal Reserve data on annual nominal returns for 10-year Treasury bonds, as provided by Damodaran Online, DOE estimated the risk free rates shown in Table 8.3.5.[q][r] DOE also estimated the ERP by calculating the difference between risk free rate and stock market return for the same time period, as estimated using Damodaran Online data on the historical return to stocks.

---

[p] U.S. Board of Governors of the Federal Reserve System, "Federal Reserve Bank Services Private Sector Adjustment Factor" (Washington, D.C., 2005), http://www.federalreserve.gov/boarddocs/press/other/2005/20051012/attachment.pdf.
[q] Damodaran, "Data Page: Historical Returns on Stocks, Bonds and Bills-United States."
[r] U.S. Office of Management and Budget, "Circular A-4: Regulatory Analysis, Appendix C: Real Interest Rates on Treasury Notes and Bonds of Specified Maturities" (Washington, D.C., 2014), http://www.whitehouse.gov/omb/circulars_a094/a94_appx-c.

Table 8.3.5 Risk Free Rate and Equity Risk Premium

Year	Risk-Free Rate (%)	ERP (%)	Year	Risk-Free Rate (%)	ERP (%)
1998	7.15	4.76	2009	7.50	2.46
1999	6.62	5.83	2010	7.47	2.51
2000	6.98	4.52	2011	7.80	1.75
2001	6.98	4.42	2012	7.78	2.62
2002	7.32	2.80	2013	7.46	4.59
2003	7.23	3.16	2014	7.65	3.86
2004	7.33	3.02	2015	7.27	3.67
2005	7.33	3.45	2016	7.26	4.21
2006	7.43	3.16	2017	7.36	4.49
2007	7.61	2.84	2018	7.34	3.90
2008	8.25	1.15			

The cost of debt financing (k_d) is the interest rate paid on money borrowed by a company. The cost of debt is estimated by adding a risk adjustment factor (R_a) to the risk-free rate. This risk adjustment factor depends on the variability of stock returns represented by standard deviations in stock prices. This same calculation can alternatively be performed with industry-level data. Tax rates also impact the cost of debt financing. Using industry average tax rates provided by Damodaran Online, DOE incorporates the after-tax.

For industry *i*, the cost of debt financing is:

$$k_{di} = \left(R_f + R_{ai}\right) \times \left(1 - tx_i\right)$$

Where:

k_{di} = (after-tax) cost of debt financing for industry, *i*,

R_f = expected return on risk-free assets,

R_{ai} = risk adjustment factor to risk-free rate for industry, *i*, and

tx_i = tax rate of industry, *i*.

DOE estimates the weighted average cost of capital using the following equation:

$$WACC = k_{ei} \times w_{ei} + k_{di} \times w_{di}$$

Where:

$WACC_i$ = weighted average cost of capital for industry i,

k_{ei} = cost of equity for industry i,

k_{di} = cost of debt financing for industry, i,

w_e = proportion of equity financing for industry i, and

w_d = proportion of debt financing for industry i.

DOE accounts for inflation using the all items Gross Domestic Product deflator, as published by the Bureau of Economic Analysis.[s] Table 8.3.6 shows the real average WACC values for the major sectors that purchase distribution transformers. Tables providing full discount rate distributions by sector are included in appendix 8E. While WACC values for any sector may trend higher or lower over substantial periods of time, these values represent a cost of capital that is averaged over major business cycles.

For each entity in the consumer sample for distribution transformers, a discount rate is drawn from the distribution calculated for the appropriate sector.

[s] National Income and Product Accounts, Table 1.1.4. Price Indexes for Gross Domestic Product (https://www.bea.gov/data/prices-inflation/gdp-price-deflator)

Table 8.3.6 Weighted Average Cost of Capital for Commercial/Industrial Sectors

Sector	Observations	Total Firms	Mean WACC (%)
Education	21	728	6.79
Food Sales	38	804	5.41
Food Service	21	1,684	6.03
Health Care	48	4,823	6.50
Lodging	21	1,488	6.05
Mercantile	89	5,048	6.64
Office	405	40,359	6.57
Public Assembly	42	3,341	6.90
Service	146	14,553	6.05
All Commercial	845	72,986	6.45
Industrial	1199	71,219	6.90
Agriculture	6	207	6.69
Utilities	101	2,066	4.02
R.E.I.T/Property	45	3,655	6.14

Note: "Observations" reflect the number of Damodaran Online detailed industries included in DOE's aggregate sector calculation, while "Total Firms" presents a sum of the number of individual companies represented by those detailed industries. These are two measures of the comprehensiveness of the data used in the WACC calculation.

For publicly owned and operated buildings, the cost of capital can be derived using state and local bond rates and U.S. Treasury bond rates.[t][u] State and local bond rates are used for buildings identified as owned and/or occupied by state or local government entities, such as public schools or local government administrative buildings. Treasury bond rates are used for buildings identified as occupied by federal government entities. Table 8.3.7 presents the average values of discount rates used for public sectors. As for private firms, a discount rate is drawn from the distribution calculated for the appropriate sector.

[t] Aswath Damodaran, "Data Page: Historical Returns on Stocks, Bonds and Bills-United States," Damodaran Online, 2019, http://pages.stern.nyu.edu/~adamodar/.
[u] Federal Reserve Bank of Saint Louis, "State and Local Bonds - Bond Buyer Go 20-Bond Municipal Bond Index," 2019, https://fred.stlouisfed.org/series/WSLB20.

Table 8.3.7 Discount Rates for Public Sectors that Purchase distribution transformers

Sector	Observations	Mean Discount Rate (%)
State/Local Govt	30	3.21
Federal Govt	30	2.90

Note: DOE used the State/Local Govt rate for publicly owned electric utilities.

8.3.4 Repair and Maintenance Costs

Maintenance costs are costs that 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. In practice, there is little scheduled maintenance for transformers beyond brief annual checks for dust buildup, vermin infestation, and accident or lightning damage. DOE assumed that the cost for general maintenance will not change with increased efficiency, therefore they were not included in this analysis.

8.3.5 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),[32] that the average life of distribution transformers is 32 years.

8.4 SIMULATION OVERVIEW

Although the LCC relies on a simple equation, DOE's LCC model accounts for the dynamic nature of numerous inputs throughout the service life of a distribution transformer. A simplified flowchart (Figure 8.4.1) illustrates the key steps implemented in the LCC model, the primary inputs, the key computational steps, and the important outputs.

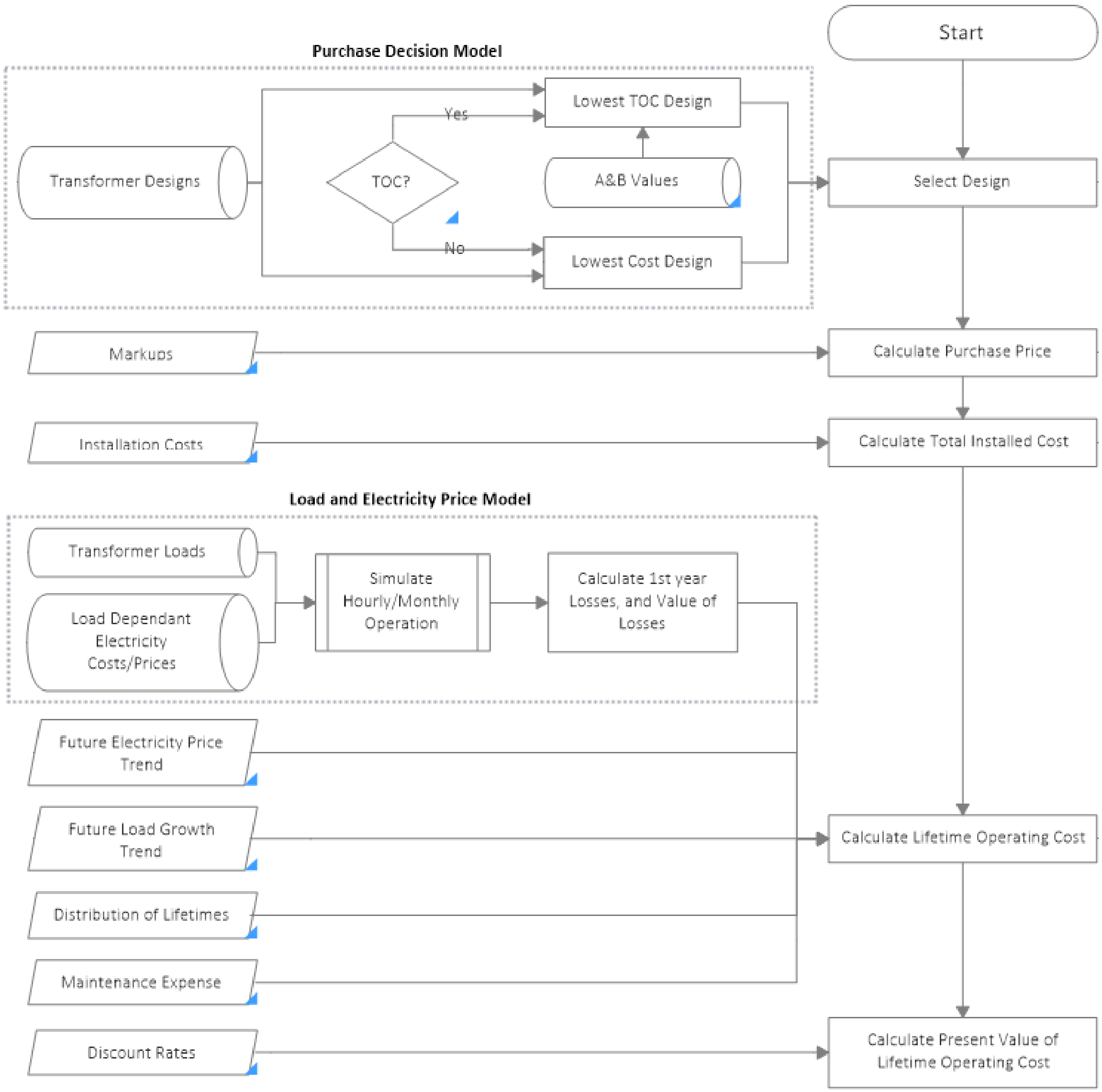


Figure 8.4.1 Flowchart of Spreadsheet Model for Calculating Transformer Life-Cycle Cost

Sections 8.4 describe the analytical steps of the LCC model shown in the flowchart. 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 representative units (section 8.5), and the key sensitivities to those results (section 8.7).

The calculation of LCC determines the financial impact 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.

8.4.1 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: 0.5 percent for liquid-immersed; 0 (zero) percent for dry-type.
- Electricity prices (relative to current estimate): zero percent.
- Transformer customer A and B parameters: 10 percent for liquid-immersed, 0 (zero) percent for dry-type.
- Future energy price trend: AEO2021 reference.

The LCC model inputs can be used to explore the sensitivities to variations of these key variables.

8.4.2 Determine Equipment

8.4.2.1 Select A and B Parameters

This step establishes the current environment for the purchasing decision. For liquid-immersed distribution transformers, DOE assumed that 90 percent are purchased based on lowest first cost and 10 percent are purchased using the TOC evaluation. DOE assumed that 100 percent of consumers of dry-type would purchase on lowest first cost.

The LCC spreadsheet uses two different models of A and B to simulate the two different distribution transformer purchase decisions. One model is used for all liquid-immersed transformer representative units, and a different model for dry-type representative units. The specific inputs to the two scenarios are given in section 8.2.3.

8.4.2.2 Select Designs that Meet a Chosen Efficiency Level

The spreadsheet model selects an efficiency level (EL) and its associated distribution transformer designs to evaluate. DOE developed as many as seven ELs for each representative unit 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.

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 distribution 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.

8.4.2.3 Calculate Equipment and Installation Costs

The model calculates markup and installation costs. For liquid-immersed distribution 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.

For dry-type distribution 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.

8.4.3 Select Load and Price Profile

The model dynamically selects a sample distribution transformer load profile from distributions derived from available data. For liquid-immersed distribution 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 distribution 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.

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 8.3.2 provides a detailed discussion of the electricity price analysis.

8.4.4 Calculate Value/Cost of Losses

The model estimates the incremental impacts of no-load and load losses from the loss coefficients of the design, the hourly or monthly customer load characteristics (demand and usage), and the cost of electricity. In this step, the model combines the no-load losses, load losses, and electricity price information for each distribution transformer in the baseline scenario and in the chosen standards scenario.

8.4.5 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 (8.3.1.3, 8.3.2.3).

8.4.6 Select Discount Rate

To discount the future stream of costs into a present value, the 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 8.3.3).

8.4.7 Calculate Present Value of Future Cost of Losses

The 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 to the future costs of losses to produce a single, present-valued number. In addition to the costs, the calculation uses as inputs the effective date of the standard, the transformer lifetime, maintenance costs, and a power factor.

8.4.8 Compile Results

The model provides the LCC, LCC savings, payback period, and other results for inclusion in the distribution of results.

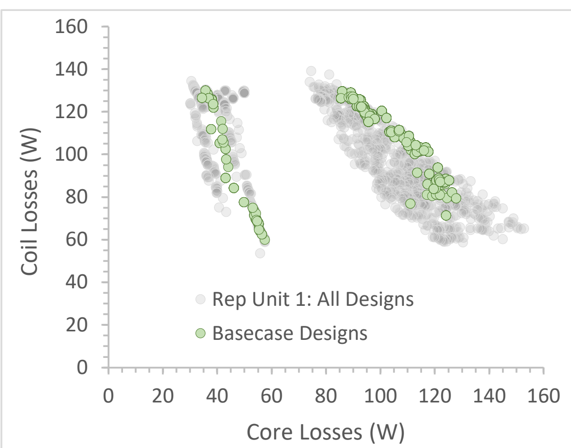
8.4.9 Repeat Process and Report Results

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 in the model. 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.

8.5 RESULTS OF LIFE-CYCLE COST ANALYSIS

This section presents LCC results for the candidate efficiency improvement levels evaluated for all 14 transformer representative units.

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 Figure 7.2.1 which shows the LL and NLL for both the basecase and, for illustrative purposes, standard level 3. As each representative unit has a unique set of engineering constraints, the LL-versus-NL graph for each will be different. This graph plots results of a simulation run of the 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 in grey. The selected designs that represent the current market are plotted as green circles. The simulated change in NLL and LL are shown in small dots in orange. As the required efficiency level increases, the cluster of selected designs moves to the toward the origin of the chart.



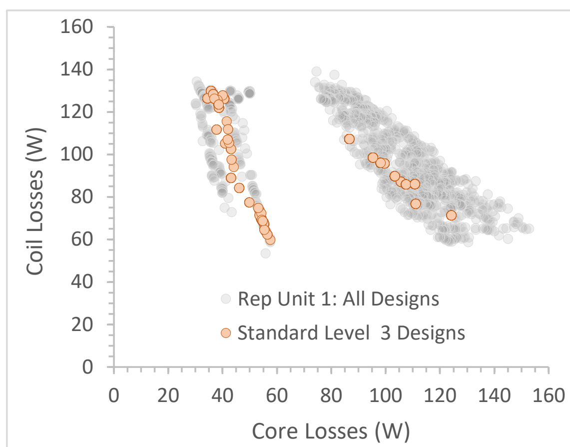


Figure 8.5.1 Selected Design Load Losses versus No-Load Losses in the Base Case and Efficiency Level 3 for Representative Unit 1

Figure 8.5.1 illustrates the distribution of results of the LCC analysis for one representative unit at one EL. The LCC spreadsheet tool can generate graphical representations such as Figure 8.5.1 for each representative unit and efficiency level.

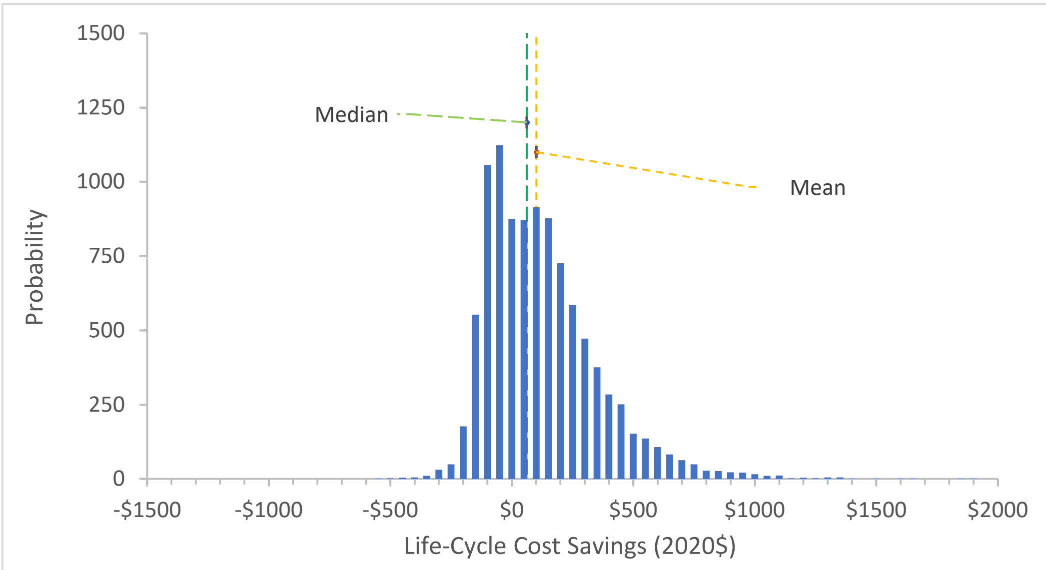


Figure 8.5.2 Distribution of Life-Cycle Cost Results for Representative unit 6, Efficiency Level 3

8.5.1 Results for Representative unit 1

Table 8.5.1 Results of Life-Cycle Cost Analysis: Representative Unit 1

Standard Level	**Average Costs (2020$)**				**Simple Payback Period (years)**	**Average Lifetime (years)**
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,532	76	1,568	4,100	-	32.0
1	2,602	74	1,524	4,126	34.8	32.0
2	2,626	73	1,505	4,131	36.6	32.0
3	2,794	69	1,412	4,206	37.0	32.0
4	2,929	54	1,159	4,088	18.4	32.0
5	3,580	41	868	4,448	30.3	32.0

Table 8.5.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 1

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	63.0	-28
2	68.5	-32
3	79.3	-108
4	45.4	12
5	85.7	-350

8.5.2 Results for Representative unit 2

Table 8.5.3 Results of Life-Cycle Cost Analysis: Representative Unit 2

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,498	43	891	2,389	-	32.0
1	1,545	43	876	2,421	117.1	32.0
2	1,578	40	830	2,408	24.9	32.0
3	1,651	32	689	2,339	14.0	32.0
4	1,735	29	626	2,361	17.4	32.0
5	2,110	24	489	2,599	31.4	32.0

Table 8.5.4 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 2

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	62.6	-34
2	60.2	-20
3	36.9	51
4	41.4	29
5	84.0	-211

8.5.3 Results for Representative unit 3

Table 8.5.5 Results of Life-Cycle Cost Analysis: Representative Unit 3

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	9,565	456	9,501	19,066	-	32.0
1	9,825	440	9,263	19,088	16.0	32.0
2	10,010	425	9,020	19,029	14.6	32.0
3	10,494	385	8,279	18,773	13.1	32.0
4	11,257	341	7,312	18,569	14.7	32.0
5	13,598	269	5,653	19,251	21.6	32.0

Table 8.5.6 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 3

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	34.2	-35
2	44.4	41
3	39.8	305
4	34.5	513
5	60.7	-188

8.5.4 Results for Representative unit 4

Table 8.5.7 Results of Life-Cycle Cost Analysis: Representative Unit 4

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	6,615	217	4,456	11,070	-	32.0
1	6,807	185	3,851	10,658	6.1	32.0
2	6,876	160	3,381	10,257	4.6	32.0
3	6,882	157	3,331	10,213	4.5	32.0
4	6,880	155	3,279	10,159	4.3	32.0
5	7,492	133	2,766	10,258	10.4	32.0

Table 8.5.8 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 4

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	31.1	484
2	6.8	906
3	4.3	954
4	2.0	1,014
5	13.7	838

8.5.5 Results for Representative unit 5

Table 8.5.9 Results of Life-Cycle Cost Analysis: Representative Unit 5

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	29,374	1,393	29,655	59,029	-	31.9
1	29,840	1,363	28,965	58,805	15.7	31.9
2	30,207	1,342	28,848	59,055	16.2	31.9
3	31,237	1,292	27,823	59,060	18.5	31.9
4	33,007	1,177	25,178	58,186	16.8	31.9
5	45,081	881	18,476	63,557	30.7	31.9

Table 8.5.10 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 5

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	21.9	481
2	38.9	-33
3	52.0	-32
4	47.8	856
5	77.9	-4,569

8.5.6 Results for Representative unit 6

Table 8.5.11 Results of Life-Cycle Cost Analysis: Representative Unit 6

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,138	94	1,236	2,374	-	32.2
1	1,140	88	1,154	2,294	0.3	32.2
2	1,176	81	1,057	2,234	2.8	32.2
3	1,235	76	992	2,227	5.2	32.2
4	1,430	70	919	2,349	12.1	32.2
5	1,633	44	582	2,216	9.9	32.2

Table 8.5.12 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 6

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	1.2	266
2	11.2	202
3	26.7	154
4	54.2	25
5	36.2	159

8.5.7 Results for Representative unit 7

Table 8.5.13 Results of Life-Cycle Cost Analysis: Representative Unit 7

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,625	204	2,648	5,273	-	31.9
1	2,652	201	2,607	5,259	8.5	31.9
2	2,682	198	2,571	5,254	9.6	31.9
3	3,296	161	2,085	5,381	15.5	31.9
4	3,425	133	1,728	5,153	11.3	31.9
5	3,591	118	1,528	5,119	11.2	31.9

Table 8.5.14 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 7

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	9.8	61
2	27.1	32
3	66.1	-108
4	42.0	120
5	41.8	154

8.5.8 Results for Representative unit 8

Table 8.5.15 Results of Life-Cycle Cost Analysis: Representative Unit 8

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	7,029	620	8,031	15,059	-	32.0
1	7,044	602	7,801	14,846	0.9	32.0
2	7,365	579	7,501	14,866	8.3	32.0
3	9,102	497	6,438	15,540	16.9	32.0
4	9,957	364	4,721	14,678	11.5	32.0
5	9,956	363	4,707	14,663	11.4	32.0

Table 8.5.16 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 8

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	6.5	425
2	31.4	204
3	78.2	-480
4	40.5	381
5	39.9	397

8.5.9 Results for Representative unit 9

Table 8.5.17 Results of Life-Cycle Cost Analysis: Representative Unit 9

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	11,870	873	11,356	23,226	-	32.1
1	11,917	861	11,207	23,124	4.2	32.1
2	12,015	836	10,881	22,896	4.0	32.1
3	13,207	695	9,043	22,250	7.5	32.1
4	13,756	623	8,101	21,857	7.5	32.1
5	15,092	547	7,123	22,215	9.9	32.1

Table 8.5.18 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 9

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	2.4	603
2	8.6	582
3	23.8	976
4	10.6	1,369
5	31.9	1,011

8.5.10 Results for Representative unit 10

Table 8.5.19 Results of Life-Cycle Cost Analysis: Representative Unit 10

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	36,234	2,537	32,782	69,017	-	31.9
1	37,655	2,446	31,619	69,274	15.7	31.9
2	39,746	2,372	30,666	70,411	21.4	31.9
3	45,538	1,866	24,121	69,659	13.9	31.9
4	48,446	1,764	22,803	71,248	15.8	31.9
5	55,282	1,591	20,576	75,858	20.1	31.9

Table 8.5.20 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 10

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	44.7	-344
2	75.1	-1,395
3	63.0	-642
4	75.0	-2,232
5	89.0	-6,841

8.5.11 Results for Representative unit 11

Table 8.5.21 Results of Life-Cycle Cost Analysis: Representative Unit 11

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	16,794	1,080	14,000	30,795	-	32.0
1	17,496	1,053	13,656	31,152	26.3	32.0
2	18,412	1,004	13,016	31,428	21.3	32.0
3	20,619	790	10,241	30,860	13.2	32.0
4	20,971	744	9,651	30,622	12.4	32.0
5	22,859	665	8,619	31,478	14.6	32.0

Table 8.5.22 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 11

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	56.9	-444
2	74.6	-633
3	55.5	-65
4	50.9	173
5	69.6	-683

8.5.12 Results for Representative unit 12

Table 8.5.23 Results of Life-Cycle Cost Analysis: Representative Unit 12

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	43,121	3,010	38,955	82,076	-	32.0
1	45,941	2,892	37,441	83,382	24.0	32.0
2	47,757	2,807	36,329	84,087	22.8	32.0
3	60,232	2,191	28,358	88,590	20.9	32.0
4	61,831	2,108	27,294	89,125	20.8	32.0
5	69,419	1,904	24,646	94,065	23.8	32.0

Table 8.5.24 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 12

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	76.6	-1,368
2	83.5	-2,010
3	95.0	-6,513
4	94.8	-7,048
5	96.4	-11,988

8.5.13 Results for Representative unit 13

Table 8.5.25 Results of Life-Cycle Cost Analysis: Representative Unit 13

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	21,065	1,200	15,640	36,705	-	32.0
1	21,542	1,159	15,115	36,657	11.8	32.0
2	22,127	1,117	14,562	36,689	12.8	32.0
3	25,705	954	12,439	38,144	18.9	32.0
4	28,031	834	10,872	38,903	19.1	32.0
5	28,535	789	10,290	38,825	18.2	32.0

Table 8.5.26 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 13

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	42.8	57
2	53.8	16
3	81.8	-1,439
4	89.9	-2,198
5	87.3	-2,119

8.5.14 Results for Representative unit 14

Table 8.5.27 Results of Life-Cycle Cost Analysis: Representative Unit 14

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	56,418	4,178	54,371	110,789	-	32.0
1	59,677	4,026	52,395	112,072	21.4	32.0
2	61,885	3,915	50,956	112,841	20.8	32.0
3	77,514	3,068	39,934	117,448	19.0	32.0
4	80,487	2,900	37,759	118,246	18.8	32.0
5	88,608	2,670	34,759	123,367	21.3	32.0

Table 8.5.28 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 14

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	81.3	-1,283
2	77.3	-2,052
3	88.1	-6,659
4	90.7	-7,457
5	96.1	-12,578

8.6 REBUTTABLE PAYBACK PERIOD

DOE presents rebuttable PBPs to provide the legally established rebuttable presumption that an energy efficiency standard is economically justified if the additional product costs attributed to the standard are less than three times the value of the first-year energy cost savings. (42 U.S.C. §6295 (o)(2)(B)(iii))

The basic calculation of rebuttable PBP is the same as that described in section 8.1.1. Unlike that analyses, however, the rebuttable PBP is not based on the use of probability distributions, and it is based not on distributions but on discrete single-point values.

8.6.1 Inputs

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.

8.6.2 Results

DOE calculated rebuttable PBPs for each efficiency level relative to the distribution of product energy efficiencies estimated for the base case. Section 8.6 presents the rebuttable PBPs for fixed speed and variable speed equipment classes.

Table 8.6.1 Rebuttable Payback Periods for Distribution Transformers

Rep Unit	Standard Level				
	1	2	3	4	5
1	14.0	9.3	14.1	25.5	19.5
2	9.3	43.6	30.1	16.5	17.3
3	0	0	0	16.6	12.8
4	6.9	5.8	5.7	4.9	6.9
5	5.8	0	35.2	10.7	15.1
6	0.2	1.8	3.1	4.6	6.8
7	2.9	2.0	10.3	10.4	7.6
8	0.8	4.4	11.5	10.8	10.7
9	2.5	2.2	5.8	6.2	6.5
10	5.9	7.9	10.3	10.5	12.3
11	8.4	9.8	12.9	11.6	10.6
12	10.9	9.5	20.1	17.7	16.1
13	4.0	5.5	10.2	18.9	15.4
14	21.3	7.5	32.0	22.6	19.1

8.7 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. For some variables, DOE went one step further by incorporating in the LCC model 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 key variables and the effect on the LCC results if they are assigned different values. The main variable examined in this analysis was electricity price trends.

This analysis examines how sensitive the LCC results are to changes in key DOE assumptions.

8.7.1 Sensitivity Results for Representative unit 1

Table 8.7.1 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 1 *(2020$)*

Standard Level	**Average Costs (2020$)**				**Simple Payback Period (years)**	**Average Lifetime (years)**
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,532	75	1,513	4,045	-	32.0
1	2,602	73	1,471	4,072	35.0	32.0
2	2,626	73	1,453	4,079	36.6	32.0
3	2,794	68	1,362	4,156	37.1	32.0
4	2,929	54	1,118	4,047	18.5	32.0
5	3,580	41	838	4,418	30.5	32.0

Table 8.7.2 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 1 ***(2020$)***

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	63.8	-29
2	69.5	-35
3	80.5	-113
4	48.5	-2
5	87.5	-375

Table 8.7.3 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 1 ***(2020$)***

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,532	76	1,611	4,143	-	32.0
1	2,602	74	1,565	4,167	34.7	32.0
2	2,626	73	1,546	4,173	36.5	32.0
3	2,794	69	1,450	4,244	36.9	32.0
4	2,929	54	1,191	4,120	18.3	32.0
5	3,580	41	892	4,472	30.2	32.0

Table 8.7.4 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 1 ***(2020$)***

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	62.2	-26
2	67.8	-30
3	78.5	-103
4	42.9	23
5	84.4	-331

8.7.2 Sensitivity Results for Representative unit 7

Table 8.7.5 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 7 *(2020$)*

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,625	201	2,553	5,179	-	31.9
1	2,652	198	2,514	5,166	8.6	31.9
2	2,682	195	2,480	5,162	9.7	31.9
3	3,296	158	2,011	5,307	15.7	31.9
4	3,425	131	1,666	5,091	11.4	31.9
5	3,591	116	1,473	5,065	11.4	31.9

Table 8.7.6 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 7 *(2020$)*

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	10.0	54
2	27.5	27
3	68.2	-128
4	45.3	88
5	45.5	114

Table 8.7.7 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 7 ***(2020$)***

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,625	207	2,727	5,353	-	31.9
1	2,652	204	2,686	5,337	8.4	31.9
2	2,682	201	2,649	5,331	9.4	31.9
3	3,296	163	2,148	5,444	15.2	31.9
4	3,425	135	1,780	5,205	11.1	31.9
5	3,591	119	1,574	5,165	11.0	31.9

Table 8.7.8 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 7 ***(2020$)***

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	9.7	66
2	26.9	36
3	64.2	-91
4	39.0	148
5	38.8	187

8.7.3 Sensitivity Results for Representative unit 12

Table 8.7.9 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 12 *(2020$)*

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	43,121	2,970	37,541	80,662	-	32.0
1	45,941	2,854	36,082	82,023	24.4	32.0
2	47,757	2,770	35,011	82,769	23.1	32.0
3	60,232	2,162	27,328	87,560	21.2	32.0
4	61,831	2,081	26,303	88,134	21.0	32.0
5	69,419	1,879	23,752	93,171	24.1	32.0

Table 8.7.10 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 12 *(2020$)*

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	77.6	-1,426
2	84.8	-2,106
3	96.1	-6,897
4	95.8	-7,471
5	97.1	-12,508

Table 8.7.11 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 12 *(2020$)*

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	43,121	3,054	40,134	83,256		32.0
1	45,941	2,935	38,575	84,516	23.7	32.0
2	47,757	2,848	37,429	85,186	22.5	32.0
3	60,232	2,223	29,216	89,448	20.6	32.0
4	61,831	2,139	28,120	89,951	20.5	32.0
5	69,419	1,932	25,392	94,810	23.4	32.0

Table 8.7.12 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 12 *(2020$)*

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	75.5	-1,320
2	82.2	-1,931
3	93.9	-6,193
4	93.6	-6,695
5	95.7	-11,555

REFERENCES

1. National Electrical Manufacturers Association. NEMA Standards Publication TP 1-2002; Guide for Determining Energy Efficiency for Distribution Transformers. (2002).

2. U.S. Department of Energy – Office of Energy Efficiency and Renewable Energy. in *Distribution Transformers Energy Conservation Standard Technical Support Document* (U.S. Department of Energy, 2007). at <http://www.regulations.gov/#!docketDetail;D=EERE-2006-STD-0099>

3. City of Glendale. *Report to City Council: Spec 3213 Power Transformer Contract Negotiation*. (City of Glendale, 2007).

4. Seattle City Light. Energy Smart Services. at <http://www.cityofseattle.net/light/conserve/business/cv5_fi.htm>

5. City of College Station - Purchasing Department. Specifications for Distribution Transformers BID #09-31. (2009). at <www.cstx.gov>

6. Clark Public Utilities. Specifications for Pad Mounted Single-Phase Distribution Transformers 12470 GRD Y/7200 Volts. (2009).

7. City of Danville. Pole Mount and Pad Mount Transformers, Bid No: IFB 10/11-011. (2010).

8. City of Concord - NC. Wire, Transformers, and Poles. (2010).

9. City of Palo Alto - Utilities Department. Specifications for Distribution Voltage Regulators Pole and Platform Type. (2009).

10. Wilson Energy Electrical Engineering. *Single Phase Overhead Conventional Transformers*. (2010).

11. U.S. Bureau of Labor Statistics. Producer Price Index Industry Data: Electric power generation, transmission, and distribution. (2011).

12. U.S. Department of Energy-Energy Information Administration. Form EIA-861: Annual Electric Power Industry Database. (2008). at <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

13. Institute of Electrical and Electronic Engineers (IEEE). *Draft Guide for Distribution Transfomer Loss Evaluation*. (IEEE, 2001).

14. Energy Information Administration - Office of Integrated Analysis and Forecasting. *The National Energy Modeling System (NEMS): An Overview*. (U.S. Department of Energy, 2009). at <http://www.eia.doe.gov/oiaf/aeo/overview/>

15. US Army Corps of Engineers. *Civil Works Construction Cost Index System (SWCCIS), Tables Revises as of 31 March 2011*. (20000331). at <http://planning.usace.army.mil/toolbox/library/Ems/em1110.2.1304.pdf>

16. U.S. Department of Energy-Federal Energy Regulatory Commission. *Form No. 714 - Annual Electric Control and Planning Area Report*. (U.S. Department of Energy-Federal Energy Regulatory Commission, 2008). at <http://www.ferc.gov/docs-filing/forms/form-714/overview.asp>

17. Coughlin, K., White, R., Bolduc, C., Fisher, D. & Rosenquist, G. *The Tariff Analysis Project: A database and analysis platform for electricity tariffs*. (Lawrence Berkeley National Laboratory, 2006).

18. Coughlin, K., Bolduc, C., Van Buskirk, R., Rosenquist, G. & McMahon, J. E. *Tariff-based Analysis of Commercial Building Electricity Prices*. (Lawrence Berkeley National Laboratory, 2008).

19. Regulatory Research Associates. *Average Regulated Retail Price of Electricity, 2007 & Comparative Historical Data*. (2008).

20. Edison Electric Institute. *EEI Typical Bills and Average Rates Report 2007-2008*. (2008).

21. Edison Electric Institute. *EEI Typical Bills and Average Rates Report 2008-2009*. (2009).

22. Edison Electric Institute. *EEI Typical Bills and Average Rates Report 2009-2010*. (2010).

23. U.S. Energy Information Administration. *Annual Energy Outlook 2012, With Projections to 2036*. (U.S. Department of Energy, 201201 01). at <http://www.eia.gov/forecasts/aeo/>

24. Ibbotson Associates. *Cost of Capital 2008 Yearbook*. (Morningstar, 2008).

25. Modigliani, F. & Miller, M. H. The Cost of Capital, Corporation Finance and the Theory of Investment. *The American Economic Review* 48, 261–297 (1958).

26. Damodaran A. Useful Data Sets. *Damodaran Online, Stern School of Business* (2010). at <http://pages.stern.nyu.edu/~adamodar/New_Home_Page/data.html>

27. U.S. Department of Commerce. Bureau of Economic Analysis. National Income and Product Accounts Table. *Table 1.1.4. Price Indexes for Gross Domestic Product* at

<http://www.bea.gov/national/nipaweb/TableView.asp?SelectedTable=4&Freq=Qtr&FirstYear=2008&LastYear=2010>

28. Damodaran, A. Damodaran Online. (2003). at <http://www.stern.nyu.edu/~adamodar/New_Home_Page/data.html>

29. Office of Management and Budget. Circular No. A-94 APPENDIX C Revised December 2009. *Discount Rates for Cost-Effectiveness, Lease Pirchase and Relate Analysis* at <http://www.whitehouse.gov/omb/circulars_a094_a94_appx-c/>

30. Federal Reserve Board. Statistics: Releases and Historical Data - Selected Interest Rates - State and Local Bonds. (2011). at <http://www.federalreserve.gov/releases/h15/data/m/slbond.txt>

31. Hopkinson, P. & Puri, J. *Distribution Transformer Market Shipment Estimates for 2001*. (HVOLT Consultants Inc., 2003).

32. Barnes, P. R., Van Dyke, J. W., McConnell, B. W. & Das, S. *Determination Analysis of Energy Conservation Standards for Distribution Transformers*. (Oak Ridge National Laboratory, 1996).

CHAPTER 9. SHIPMENTS ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

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 any proposed standards. 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.

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 distribution transformers throughout the forecast period (2027–2056). 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 distribution 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 cars or lightning, or otherwise fail in the field and 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 distribution 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.

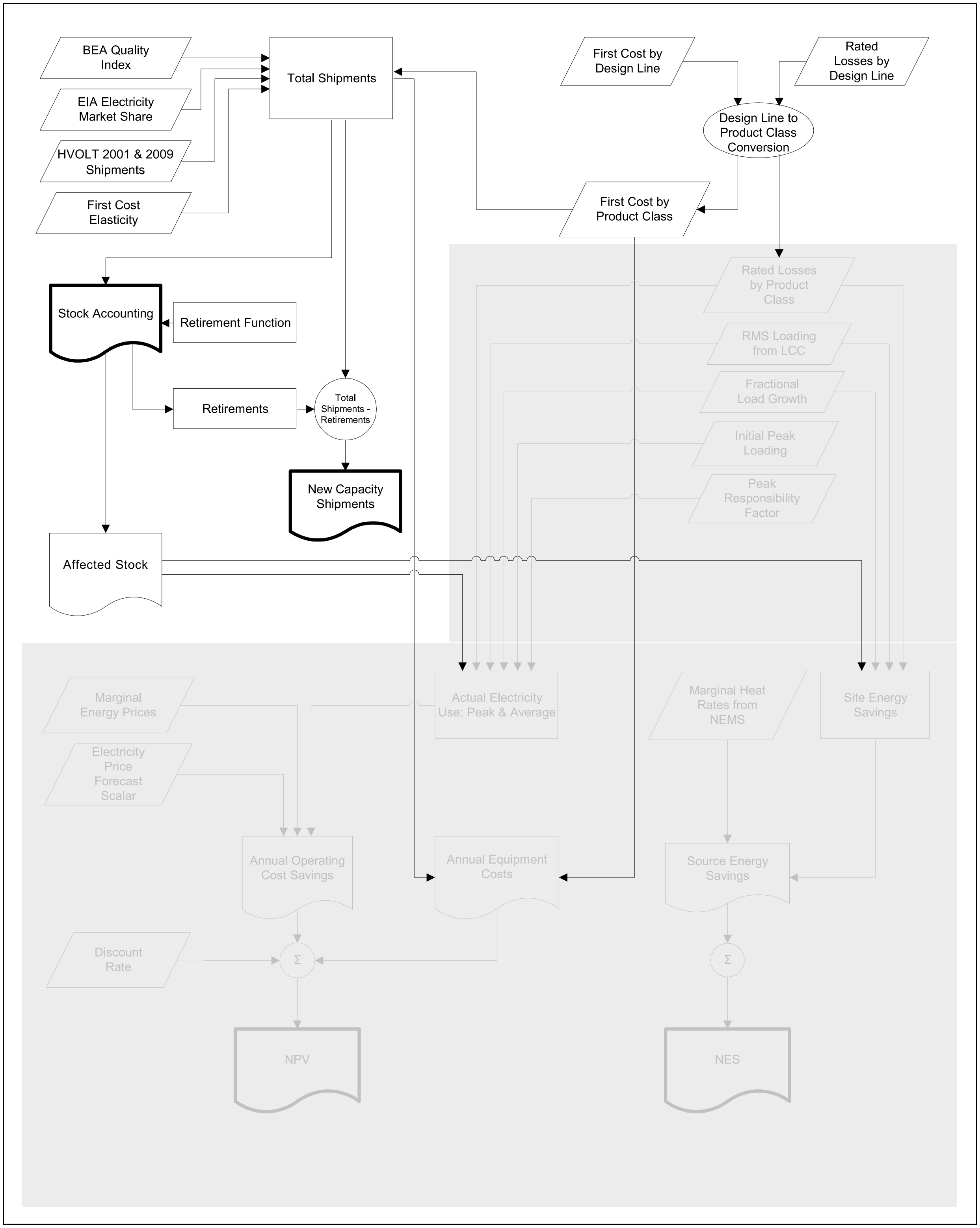


Figure 9.2.1 Flowchart of Shipments Model

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. Long-term price elasticity of transformer purchases is estimated outside the model and is thus introduced exogenously in the Shipments Model. The outputs of the shipments analysis are estimates of annual shipments and the age distribution of in-service distribution 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, 2009, 2012, and 2018. The quantity index of transformers manufactured is available for 1977–2018.

2. Shipments backcast, an estimate of transformer capacity shipped before 2020.

3. Shipments forecast, an estimate of distribution transformers shipped after 2020.

4. Annual market shares of liquid-immersed and dry-type transformers shipped, categorized by capacity.

5. 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.

6. Retirement function that provides an estimate of the probability that a transformer will be replaced as a function of its age.

7. Long-term price elasticity of transformer purchases was not included in this analysis.

    a. Refurbishments and rewinds, to accurately capture whether or not a unit is replaced upon failure or refurbished/rewound.

8. The initial stock of transformers at the start of the stock-accounting calculation (in 1950).

9. Effective date of standard (2027) 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 National Energy Saving (NES), and Net Present Value (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. DOE also received aggregated sales data from several manufacturer disaggregated by transformer type (pole-mounted, network or vault, and greater than 200 kV BIL) the share of shipments and purchases from various manufacturers and utilities, for 2010, and 2011. 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.

Table 9.3.1 Estimated Shipments of Distribution Transformers, 2021

Equipment Class		Units Shipped	Capacity Shipped (MVA)
1	Liquid-immersed, medium-voltage, single-phase	754,357	29,170.1
2	Liquid-immersed, medium-voltage, three-phase	54,891	33,572.6
3	Dry-type, low-voltage, single-phase	20,119	735.3
4	Dry-type, low-voltage, three-phase	234,684	17,899.8
5	Dry-type, medium-voltage, single-phase, 20–45 kV BIL*	804	26.1
6	Dry-type, medium-voltage, three-phase, 20–45 kV BIL	592	291.8
7	Dry-type, medium-voltage, single-phase, 46–95 kV BIL	619	26.2
8	Dry-type, medium-voltage, three-phase, 46–95 kV BIL	2,352	4,145.7
9	Dry-type, medium-voltage, single-phase, ≥ 96 kV BIL	229	9.7
10	Dry-type, medium-voltage, three-phase, ≥ 96 kV BIL	1,459	2,501.6

* BIL = basic impulse insulation level.

To distribute the units shipped to the rated capacities within each EC DOE averaged the relative weight of each rated capacity provided by HVOLT in 2009, with the capacities in the IEE Dominion datasets.

Table 9.3.2 and Table 9.3.3 presents the shipment estimates for 2021 for medium-voltage liquid-immersed distribution transformers categorized by capacity, application (overhead or pad) and number of phases.

Table 9.3.2 Estimated Shipments of Liquid-Immersed Medium-Voltage Distribution Transformers (MVA), 2021

Equipment Class	1	1	1	2	2	2	2
Phases	1	1	1	3	3	3	3
Rep Unit	1	2	3	4	4	5	5
Application	Pad	OH	OH	OH	Pad	OH	Pad
10	19.4	2044.6					
15	134.1	4223.7					
25	1286.3	9447.8					
30				31.0	4.7		
38	234.6	1308.0					
45				313.8	323.9		
50	2266.7	4291.5					
75	1223.6	692.2		299.6	2957.6		
100	941.1	588.7					
113				43.2	803.7		
150				357.0	5923.9		
167	237.1	169.9					
225				7.4	1347.5		
250	3.8		14.5				
300				121.5	5921.9		
333	0.1		25.5				
500	0.1		14.0		4473.8		
667	0.2						6.1
750							2746.4
833	2.0		0.6				17.5
1,000							2460.3
1,500							2668.8
2,000							1064.8
2500							1678.2
Total MVA	6349.1	22766.3	54.7	1173.5	21757.1		10642.0

Table 9.3.3 Estimated Shipments of Liquid-Immersed Medium-Voltage Distribution Transformers (units), 2021

Equipment Class	**1**	**1**	**1**	**2**	**2**	**2**	**2**
Phases	1	1	1	3	3	3	3
Rep Unit	1	2	3	4	4	5	5
Application	Pad	OH	OH	OH	Pad	OH	Pad
10	502	52,873	0	0	0	0	0
15	3,469	109,226	0	0	0	0	0
25	33,265	244,326	0	0	0	0	0
30	0	0	0	51	8	0	0
38	6,067	33,825	0	0	0	0	0
45	0	0	0	513	530	0	0
50	58,618	110,981	0	0	0	0	0
75	31,642	17,902	0	490	4,836	0	0
100	24,337	15,224	0	0	0	0	0
113	0	0	0	71	1,314	0	0
150	0	0	0	584	9,686	0	0
167	6,132	4,393	0	0	0	0	0
225	0	0	0	12	2,203	0	0
250	99	0	376	0	0	0	0
300	0	0	0	199	9,682	0	0
333	3	0	660	0	0	0	0
500	2	0	362	0	7,315	0	0
667	4	0	0	0	0	0	10
750	0	0	0	0	0	0	4,490
833	52	0	15	0	0	0	29
1,000	0	0	0	0	0	0	4,023
1,500	0	0	0	0	0	0	4,363
2,000	0	0	0	0	0	0	1,741
2500	0	0	0	0	0	0	2,744
Total Units	164,193	588,751	1,413	1,919	35,573	0	17,400

Table 9.3.4 and Table 9.3.5 show the shipment estimates for 2021 for dry-type low-voltage distribution transformers categorized by capacity and number of phases.

Table 9.3.4 Estimated Shipments of Dry-Type, Low-Voltage Distribution Transformers (MVA), 2021

Equipment Class	**3**	**4**	**4**
Phases	1	3	3
Rep Unit	6	7	8
BIL	10	10	10
10			
15	37.4	463.0	
25	122.0		
30		1891.5	
38	101.5		
45		2702.4	
50	192.2		
75	157.0	5234.6	
100	122.2		
113		3188.1	
150		3122.3	
167			
225			530.9
250	3.1		
300			345.8
333			
500			311.9
667			
750			102.7
833			
1,000			3.5
1,500			3.2
2,000			
2500			
Total MVA	735.3	16601.9	1297.9

Table 9.3.5 Estimated Shipments of Dry-Type, Low-Voltage Distribution Transformers (Units), 2021

Equipment Class	3	4	4
Phases	1	3	3
Rep Unit	6	7	8
BIL	10	10	10
10	1	0	0
15	1,022	6,071	0
25	3,338	0	0
30	0	24,800	0
38	2,777	0	0
45	0	35,431	0
50	5,258	0	0
75	4,295	68,631	0
100	3,343	0	0
113	0	41,799	0
150	0	40,936	0
167	0	0	0
225	0	0	6,960
250	86	0	0
300	0	0	4,533
333	0	0	0
500	0	0	4,090
667	0	0	0
750	0	0	1,347
833	0	0	0
1,000	0	0	45
1,500	0	0	42
2,000	0	0	0
2500	0	0	0
Total Units	20,119	217,667	17,017

Table 9.3.6 and Table 9.3.7 shows the shipment estimates for 2021 for dry-type medium-voltage distribution transformers categorized by capacity and by whether single- or three-phase.

Table 9.3.6 Estimated Shipments of Dry-Type, Medium-Voltage Distribution Transformers (MVA), 2021

Equipment Class	**5**	**5**	**6**	**6**	**7**	**7**	**8**	**8**	**9**	**9**	**10**	**10**
Phases	1	1	3	3	1	1	3	3	1	1	3	3
Rep Unit	9V	10V	9	10	11V	12V	11	12	13V	14V	13	24
BIL	45	45	45	45	95	95	95	95	125	125	125	125
10	4.7				4.2				1.5			
15	6.4		0.3		5.7				2.0			
25	2.2				1.9				1.0			
30			1.1									
38	3.1				2.6				1.4			
45			1.4									
50	1.9				1.6				0.8			
75	2.6		0.7		2.1		1.2		1.1			
100	1.3				2.6				0.8			
113			8.6				3.3					
150			12.3				5.1					
167	1.1				1.9				0.6			
225			13.9				16.6					
250		0.9				1.6				0.2		
300		1.1	54.0				51.4				51.0	
333		0.9				1.9				0.3		
500			154.5				213.5				221.3	
667												
750				25.4				123.2				73.3
833												
1,000				19.7				305.7				235.1
1,500								621.4				400.8
2,000								1285.1				570.8
2500								1519.3				949.4
Total	23.1	3.0	246.8	45.1	22.7	3.5	291.0	3854.7	9.3	0.5	272.2	2229.4

* BIL = basic impulse insulation level.

Table 9.3.7 Estimated Shipments of Dry-Type, Medium-Voltage Distribution Transformers (Units), 2021

Equipment Class	**5**	**5**	**6**	**6**	**7**	**7**	**8**	**8**	**9**	**9**	**10**	**10**
Phases	1	1	3	3	1	1	3	3	1	1	3	3
Rep Unit	9V	10V	9	10	11V	12V	11	12	13V	14V	13	24
BIL	45	45	45	45	95	95	95	95	125	125	125	125
10	145	0	0	0	100	0	0	0	35	0	0	0
15	196	0	1	0	136	0	0	0	48	0	0	0
25	69	0	0	0	44	0	0	0	23	0	0	0
30	0	0	2	0	0	0	0	0	0	0	0	0
38	94	0	0	0	60	0	0	0	32	0	0	0
45	0	0	3	0	0	0	0	0	0	0	0	0
50	58	0	0	0	37	0	0	0	20	0	0	0
75	79	0	2	0	50	0	1	0	26	0	0	0
100	39	0	0	0	62	0	0	0	20	0	0	0
113	0	0	17	0	0	0	2	0	0	0	0	0
150	0	0	25	0	0	0	3	0	0	0	0	0
167	33	0	0	0	46	0	0	0	14	0	0	0
225	0	0	28	0	0	0	9	0	0	0	0	0
250	0	29	0	0	0	37	0	0	0	5	0	0
300	0	33	110	0	0	0	29	0	0	0	30	0
333	0	29	0	0	0	46	0	0	0	7	0	0
500	0	0	313	0	0	0	121	0	0	0	129	0
667	0	0	0	0	0	0	0	0	0	0	0	0
750	0	0	0	51	0	0	0	70	0	0	0	43
833	0	0	0	0	0	0	0	0	0	0	0	0
1,000	0	0	0	40	0	0	0	173	0	0	0	137
1,500	0	0	0	0	0	0	0	353	0	0	0	234
2,000	0	0	0	0	0	0	0	729	0	0	0	333
2500	0	0	0	0	0	0	0	862	0	0	0	554
Total	713	91	501	91	536	83	165	2,187	218	12	159	1,300

* BIL = basic impulse insulation level.

The shipments model incorporates two major assumptions. The first is that the relative market shares of the various distribution 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 1977–2016. 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 1977–2016.[4] Specifically, DOE used the following equation to backcast shipments from 2016 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 $1977 \leq y < 2016$ (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, this is unchanged from the 2013 final rule.[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 2012 (*AEO 2021*).[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 *AEO2021* forecast through 2050.[7] For years beyond 2050, DOE assumed flat, no, growth. 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 2021 < y ≤ 2050 (MVA); and
AllElec(y)	=	the national electricity consumption for year *y* (kWh) forecasted by *AEO2021*.

The following section describes how DOE adjusted its base-case forecast to account for price increases arising from each candidate standard.

9.3.4 Long-Term Price Elasticity

For this preliminary analysis DOE did not consider a long-term price elasticity for distribution transformers, this section broadly discusses the approach DOE will take in the NOPR.

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.

Distribution transformers are a critical component of electrical infrastructure, as such their purchase and inclusion in circuit design and construction can not be avoided, foregone, or substituted with other equipment. As such DOE understands that the consumer response to increased distribution transformers would likely be to purchase equipment that is out of scope of DOE's authority, *i.e.* previously owned equipment. DOE's approach for how it will determine the impacts of consumers swathing to these, or refurbished equipment is discussed in section 9.3.4.1.

9.3.4.1 Refurbishments and Rewinds

Transformers that are not retired can be refurbished and returned to the stock, the nature of these refurbishments takes two forms:

1) ***Repair***: This entails minor repairs, generally the failed transformer is removed from its location, disassembled into its major components, cleaned, damaged minor parts replaced, and it is then reassembled, repainted and returned to service. Based on stakeholder comments these repairs may increase the life of a transformer up to 10 years.

2) ***Rebuild***: This is a more extensive repair, as it encompasses all of the steps for repair above, plus the transformer's original coil is unwound from the core and replaced with new windings (rewinding); this is an operation often performed by a specialized firm. A rebuild may increase the life of the transformer to that of a new unit, but this is entirely dependent of the skill of the rebuilder. Because of this, the quality of rebuilt distribution transformers is a concern for some utilities and currently inhibits widespread adoption.

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, while there is concern that the market penetration of transformers rebuilt by third-parties will grow, DOE was unable to identify data to support these claims. Currently, rebuilt transformer appears to represent a very small fraction of the distribution transformer market; however, that share could increase in response to the imposition of an energy efficiency standard.

Information shared with DOE from transformer customers suggest that the majority of failed transformers are scrapped rather than rebuilt and returned to service. A failed transformer's vintage, or the type and amount damage are factors that are taken into consideration before deciding whether a unit should be rebuilt or scrapped. Scrapped units may be sold to a third-party transformer repair shop, which will recycle, or refurbish the units and return them to market.

The practice of transformer repair is believed to be widespread; as such is modeled as part of the retirement function in the shipments analysis.

The practice of rebuilding[a], and the purchasing of refurbished transformers from third-parties is currently believed to be a very small fraction of the overall market. As such, the choice to purchase a refurbished or rebuild an existing failed transformer instead of purchasing a new unit is implicitly included in the initial purchase price elasticity function in the shipments analysis. In the final rule, DOE added several free parameters to the shipments model to set what fraction of displaced new shipments are refurbished (rebuilt, and combined third-part repaired and rebuilt) distribution transformers. DOE estimated average values for all refurbished are as follows:

1) The percent of displace shipments in the standards case that are refurbished units: 20 percent
2) The average lifetime of refurbished units: 20 years
3) The average cost of refurbished units: 75 percent of basecase units
4) The average efficiency of refurbished units: -25 percent of the basecase units.

[a] Based on survey results of 68 utilities conducted by ORNL in 1995 estimated that less than 2 percent of the refurbished capacity were rebuilt/rewound tranformers.[9]

After DOE specified the retirement probability function, the remaining input to the stock-accounting equation was the initial in-service stock of distribution transformers, as described in the following sections.

9.3.5 Market Shares of Liquid-Immersed and Dry-Type Distribution Transformers

The shipments forecast and backcast described above provided an aggregate estimate of the total capacity of distribution transformers shipped from 1950 to 2050. 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, size categories and different installations (overhead, surface, or network/vault/submersible) within each equipment class, DOE used estimates of market shares from 2001, 2009, 2012 and 2020. The three different data sets used to characterize the market shares do not share the same properties. The datasets for 2001, and 2009 contain estimated transformer sales by capacity and phase-count for all transformer equipment classes, however this they do not contain installation information. However, the 2012 and 202 data contain detail installation information, capacities, and phase-counts, but the dataset only covers liquid-immersed transformers.

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.

$$LiqShip(y) = CL \times AllElec(y),$$
$$\text{where } CL = LiqShip(2001) / AllElec(2001) \ \forall\, y \leq 2008 \text{ and}$$
$$CL = LiqShip(2009) / AllElec(2009) \ \forall\, y \geq 2009.$$

$$DryShip(y) = CD \times CIElec(y),$$
$$\text{where } CD = DryShip(2001) / CIElec(2001) \text{ for all } y \leq 2008 \text{ and}$$
$$CD = DryShip(2009) / CIElec(2009) \text{ for all } y \geq 2009.$$

$$DryMS(y) = CD \times CIElec(y) / (CL \times AllElec(y) + CD \times CIElec(y)).$$

$$LiqMS(y) = 1 - DryMS(y).$$

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 distribution transformers likely are complicated, 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 distribution 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 distribution 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 distribution 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]

$$r(age) = exp\left[-\left(\frac{age}{d}\right)^{d}\right].$$

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; and

d and e = parameters used for fitting the reliability data;

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:

$$Prob_{Retire}(age) = \frac{[r(age-1) - r(age)]}{r(age)}$$

Where:

$Prob_{Retire}(age)$ = the probability that a transformer of a particular age will be retired.

DOE considered the possibility that more efficient distribution 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.

9.3.8 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 distribution 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 2020.

---

[a] Note that transformer stocks in 1950 were small compared to those in 2001.

9.3.9 Effective Date of Standard

A key output of the shipments model is the in-service stock of distribution 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 2027. The exact effective date of the standard is assumed to be January 1, 2027, so all distribution transformers manufactured or imported starting on the first day of 2027 are affected by the standard.

9.3.10 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.

$$Aff_{Stock}(y) = Ship(y) + \sum_{age=1}^{y-StdYear} Stock(age)\,.$$

Where:

$Aff_{Stock}(y)$	=	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 2027 through 2056. Total shipments depend on transformer lifetime, and growth in new electricity demand. Annual shipments for liquid-immersed and dry-type distribution transformers throughout the forecast period are shown in Table 9.4.1.

Table 9.4.1 Annual Shipments of Distribution Transformers, 2027–2056 *MVA*

	Liquid-Immersed	Low-Voltage Dry-Type	Medium-Voltage Dry-Type
2027	62,743	18,635	7,001
2028	63,157	18,752	7,045
2029	63,531	18,844	7,080
2030	63,749	18,893	7,098
2031	64,015	18,957	7,122
2032	64,286	19,016	7,144
2033	64,595	19,089	7,172
2034	64,968	19,172	7,203
2035	65,381	19,271	7,240
2036	65,808	19,371	7,278
2037	66,260	19,482	7,319
2038	66,734	19,607	7,366
2039	67,183	19,720	7,409
2040	67,550	19,818	7,446
2041	67,957	19,931	7,488
2042	68,366	20,039	7,529
2043	68,805	20,155	7,572
2044	69,259	20,272	7,616
2045	69,736	20,397	7,663
2046	70,260	20,542	7,717
2047	70,791	20,690	7,773
2048	71,273	20,830	7,826
2049	71,762	20,975	7,880
2050	72,331	21,143	7,943
2051	72,784	21,268	7,990
2052	73,239	21,394	8,038
2053	73,697	21,521	8,085
2054	74,158	21,649	8,133
2055	74,623	21,777	8,181
2056	75,089	21,906	8,230

REFERENCES

1. Hopkinson, P. & Puri, J. *Distribution Transformer Market Shipment Estimates for 2001*. (HVOLT Consultants Inc.: Washington DC, 2003).

2. Hopkinson, P. & Puri, J. *Distribution Transformer Market Shipment Estimates for 2009*. (HVOLT Consultants Inc.: Washington DC, 2010).

3. U.S. Department of Commerce-Bureau of Economic Analysis *National Economic Accounts: National Income and Product Accounts Tables (1969-Present)*.

4. U.S Department of Commerce-Bureau of Economic Analysis *Industry Economic Accounts Information Guide. Annual industry accounts: gross domestic product (GDP) by industry*. (2010).

5. U.S. Department of Energy-Energy Information Administration *Annual Energy Review 2009, Chapter 8: Electricity, Table 8.9 Electricity End Use, 1949-2009*. (U.S. Department of Energy: Washington DC, 2010).

6. U.S. Energy Information Administration *Annual Energy Outlook 2012, With Projections to 2036*. (U.S. Department of Energy: Washington DC, 2011).

7. U.S. Department of Energy – Energy Information Administration *Annual Energy Outlook 2021: With Projections Through 2050*. (U.S. Department of Energy: Washington DC, 2021).

8. U.S. Department of Labor-Bureau of Labor Statistics *Producer Price Index. Industry: Refrigeration and Heating Equipment-Product: Unitary Air Conditioners-Series ID: PCU3585#2 (N)*. (2005).

9. Barnes, P.R., Dyke, J.W.V., McConnell, B.W., Cohn, S.M. & Purucker, S.L. *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance*. (Oak Ridge National Laboratory: 1995).

CHAPTER 10. NATIONAL IMPACT ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 10. NATIONAL IMPACT ANALYSIS

10.1 INTRODUCTION

The Energy Policy and Conservation Act of 1975, as amended, (EPCA) requires that any new or amended energy efficiency standard for distribution transformers shall be designed to achieve the maximum improvement in energy efficiency that is both technologically feasible, economically justified, and would save a significant amount of energy. (42 U.S.C. 6295(o)(2)(A) and (B), and 6317(a)(1). In determining whether a standard is economically justified. the U.S. Department of Energy (DOE) is required to determine whether the benefits of the potential standard outweigh its burdens. Key factors in the determination are (1) the total projected amount of energy savings likely to result directly from the imposition of the standard, and (2) the savings in operating costs throughout the life of the covered equipment when compared to any increase in its price, initial charges, such as installation costs, or maintenance‒any of which are likely to result from promulgation of the standard.

To satisfy the above EPCA requirements and more fully understand the overall impact of potential energy 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 distribution transformers and the national economic impact using the net present value (NPV). This chapter describes the methodology DOE used to estimate the national impacts of trial standard levels (TSLs) for medium-voltage liquid-immersed distribution transformers, and low- and medium-voltage dry-type distribution transformers. The analyses that preceded the shipments analysis in chapter 9 of the Technical Support Document (TSD) (e.g., the engineering analysis (chapter 5) and the life-cycle cost analysis (chapter 8) examined transformers by design-line, which accounts for the 14 distinct design options found in transformers. for the NIA, DOE is required to 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 trial standard level being considered for distribution transformers. DOE performed all calculations for each considered equipment class using a model.

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 TSD.

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), thereby enabling DOE to estimate the stock that would be affected by trial standard levels and transformer retirements.

DOE used a scaling factor (described in section 10.2.2) 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, in terms of transformer capacity (kVA), within that equipment class.

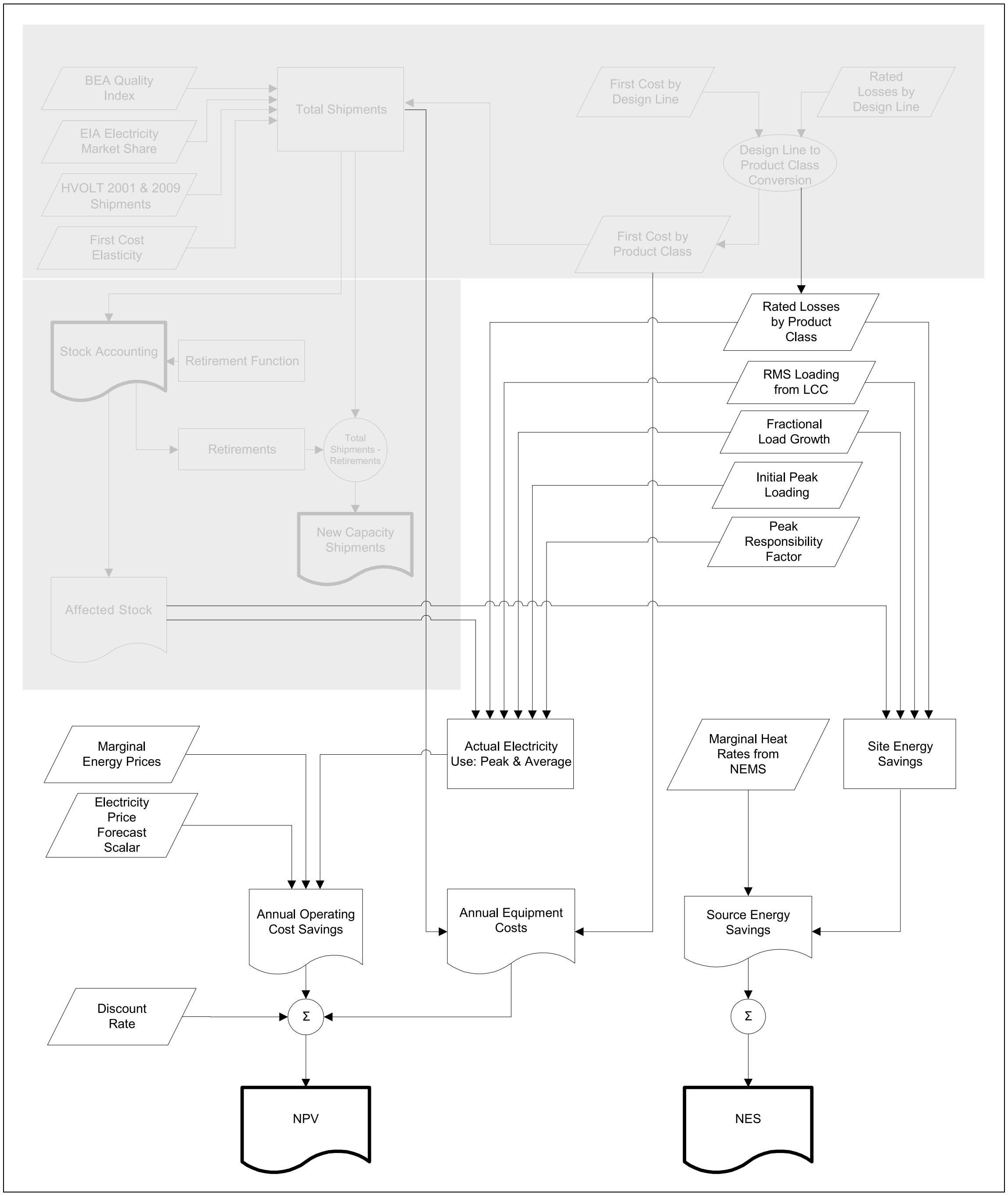


Figure 10.1.1 Flowchart of National Impact Analysis

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 in to average equipment classes. 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 no new standards case and standards case 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 2027 through 2056, provides the final NES result.

On the other path, the NPV calculation starts with marginal price/cost of electricity inputs from the LCC analysis 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 analyzed candidate standard level (CSL).

1. The difference was between equipment costs in each CSL scenario and the base case to obtain the net increase in equipment cost attributable to the CSL.
2. The difference was between operating costs under the base-case scenario and each CSL to obtain the net operating cost savings from the CSL.
3. The 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 CSL, DOE discounted the net expenses or savings to 2021$ and summed them for 2021–2114[a] (the year the last unit shipped in 2054 retires from service) for transformers purchased during 2027–2056.

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

10.2.1 Definition

DOE calculates annual NES for a given year as the difference between the national annual energy consumption (AEC) in a no-new-standards case and a standards case. Cumulative energy savings are the sum of annual NES throughout the analysis period.

[a] The analysis period for NPV is based on the cumulative operating cost savings of the last unit shipped (2056 + maximum transformer life -1).

In determining national AEC, DOE first calculates AEC at the site. DOE calculates the national annual site energy consumption by multiplying the number or stock of the distribution transformers (by vintage) by its unit energy consumption (also by vintage). National annual energy consumption is calculated using the following equation:

$$AEC_{S_y} = \sum STOCK_V \times UEC_V$$

Where:

AECs	=	annual national site energy consumption in quadrillion British thermal units (quads),
$STOCK_V$	=	stock of distribution transformers of vintage *V* that survive in the year for which DOE calculates the AEC,
UEC_V	=	annual energy consumption per unit of distribution transformer,
V	=	year in which the distribution transformers was purchased as a new unit,
y	=	year in the forecast.

The stock of distribution transformers depends on annual shipments and the lifetime of the distribution transformers. As described in chapter 9 of this TSD, DOE projected distribution transformers shipments under the no-new-standards case and standards cases. To avoid including savings attributable to shipments displaced (units not purchased) because of standards, DOE used the projected standards-case shipments and, in turn, the standards-case stock, to calculate the AEC for the no-new-standards case.

DOE applies conversion factors to site energy to calculate primary AEC and to primary energy to calculate FFC AEC.

10.2.2 Scaling of Losses and Costs

Transformers are produced over a broad range of capacities, only a few of which are modeled explicitly in the engineering 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.

DOE used the following methodology to scale the losses and costs produced by the LCC for use in the NIA:

10.2.2.1 Life-cycle Cost Output

The independent variables that describe the equipment and installation characteristics (denoted by: q) are as follows:

c = labels the equipment class; equipment classes are defined based on phase (single- and three-phase) and insulation type (liquid-immersed and dry-type),

j = labels the design line (also called the representative unit); a design line corresponds to a specific set of values for equipment class c, capacity K, and application a,

K_j = labels the rated capacity in kVA for design line j,

A = labels the application; the two main applications for liquid-immersed products are overhead (pole-mounted) and pad-mounted; vault is treated in a sub-group analysis.

The independent variables that describe the consumer characteristics (denoted by: b) are:

r = labels the region (census divisions),

s = labels the end-use sector served by the equipment (residential, commercial, industrial).

p = labels the ownership type (public or investor-owned),

There is a separate LCC for each representative unit (RU) analyzed in the engineering. In connecting the LCC to the shipments, each modeled RU is used to represent the characteristics of transformers over a range of capacities. Table 1 provides the correspondence between DL, capacity, equipmentclass *etc.*

The dependent variables calculated in the LCC and exported to the downstream models are Purchase Price, Installation Cost, Annual Energy Use, Age, Repair Cost, Maintenance Cost, and Effective Marginal Price of Electricity. These variables are defined for each RU, as well as for eachefficiency level (EL). Table 10.2.1 shows the characteristic of each RU for which LCC variables and exported to the NIA.

Table 10.2.1 Mapping of Rep Unit to Equipment Characteristics

Type	EC *c*	Phases	RU *j*	BIL	Capacity (kVA) K_j	Cap Min (kVA)	Cap Max (kVA)	Application
LI	1	1	1	95	50	10	833	Pad
LI	1	1	2	25	25	10	167	OH
LI	1	1	3	95	500	250	833	OH
LI	2	3	4	95	150	15	500	Pad
LI	2	3	4	95	150	15	500	OH
LI	2	3	5	95	1500	500	2500	Pad
LI	2	3	5	95	1500	750	2500	OH
LVDT	3	1	6	10	25	15	333	ALL
LVDT	4	3	7	10	75	15	150	ALL
LVDT	4	3	8	10	300	225	2500	ALL
MVDT	5	1	9V	45	100	10	167	ALL
MVDT	5	1	10V	45	500	255	833	ALL
MVDT	6	3	9	45	300	15	500	ALL
MVDT	6	3	10	45	1500	667	2500	ALL
MVDT	7	1	11V	95	100	10	167	ALL
MVDT	7	1	12V	95	500	250	833	ALL
MVDT	8	3	11	95	300	15	500	ALL
MVDT	8	3	12	95	1500	667	2500	ALL
MVDT	9	1	13V	125	100	10	167	ALL
MVDT	9	1	14V	125	667	250	833	ALL
MVDT	10	3	13	125	300	15	500	ALL
MVDT	10	3	14	125	2000	667	2500	ALL

10.2.2.2 Shipments and NIA Model

The consumer variable that is carried through to the NIA is the ownership type, either: investor owned utility or publicly owned utility (Co-ops or Munis). Averaging over region and sector can be done through a simple average of the LCC output, as these characteristics are already weighted within the LCC. Relative weights by ownership type aredenoted v_p and must be input to the shipments model. These weights don't depend on any other variable.

The equipment variables that are to be carried through to the NIA include the EC and the application. The LCC data is averaged over capacity before combined with the shipments data.

The shipments data provide shipments by EC for a larger range of capacities than there are RUs. The LCC results for modeled RUs are extrapolated to these additional categories by using the "0.75 scaling rule". Described in chapter 5, is a physical scaling rule that relates losses and material costs to the capacity of the transformer. For two rated capacities K and K', and a variable X that depends on K, the rule is:

$$\frac{X(K')}{X(K)} = \left(\frac{K'}{K}\right)^{0.75}$$

The scaling rule holds for transformer price, weight, no-load losses and total losses.

The variable $K_{c,m}$ is used to denote the capacities listed in the shipments data for EC c. For example: EC1 (liquid-immersed single-phase transformers) these capacities are:

$$\{K_{1,m},\ \ m = 1 \ldots 12\} = \{10, 15, 25, 37.5, 50, 75, 100, 167, 250, 500, 667, 833\}.$$

For EC2 (three-phase) they are:

$$\{K_{2,m},\ m = 1 \ldots 14\} = \{15, 30, 45, 75, 112.5, 150, 225, 300, 500, 750, 1000, 1500, 2000, 2500\}.$$

The shipment weight assigned to $K_{c,m}$ is $w_{c,m}$. Table 10.2.2 shows how each DL is assigned to a range of shipment capacities; for example, RU1 with $K = 50$ is used to estimate results for all pad mounted capacities $K_{1m} \leq 167$.

For a given ownership type, EC, and application, the capacity-averaged value of X is defined as:

$$\bar{X}_{c,a,p} = \sum_{m} w_{c,m} \left(\frac{K_{c,m}}{K_j}\right)^{0.75} X_{j,p}$$

Where the RU j has to be chosen to match the given value of c and a, and the range of m must be appropriate to the value of j. When extracting the population-averaged value of X from the LCC, only rows corresponding to ownership p should be included.

As an example, the equation below defines the capacity-averaged value of X for EC1 and the overhead (OH) application. This EC and application is represented by RUs 2 and 3. For each value of p the average is:

$$\bar{X}_{c,a,p} = \left(\sum_{m=1}^{8} w_{1,m} \left(\frac{K_{1,m}}{K_2}\right)^{0.75}\right) X_{2,p} + \left(\sum_{m=9}^{12} w_{1,m} \left(\frac{K_{1,m}}{K_3}\right)^{0.75}\right) X_{3,p}$$

The terms in brackets in the equation don't depend on the LCC itself, and were calculated separately. A simple implementation of the aggregation and scaling of the LCC data is to define amatrix $M_{c,a,j}$ such that:

$$\bar{X}_{c,a,p} = M_{c,a,j} X_{j,p}$$

The weights $M_{c,a,j}$ depend only on the shipments data and the mapping of RUs to application and EC, and are the same for all variables that are scaled using the 0.75 rule. The average across ownership types is then:

$$\bar{X}_{c,a} = \sum_{p} v_p \bar{X}_{c,a,p}$$

From Table 10.2.2, for the five rep units that constitute DOE's representation of liquid-immersed distribution transformers map to 3 unique combinations of *c* and *a*: EC1-Pad (RU1), EC1-OH (RU2 and RU3) and EC2-pad (RU4 and RU5). The corresponding non-zero matrix elements are given below. The same calculations were conducted for the dry-type rep units shown in Table 10.2.3.

$$M_{1,pad,1} = \left(\sum_{m=1}^{8} w_{1,m} \left(\frac{K_{1,m}}{K_1} \right)^{0.75} \right),$$

$$M_{1,oh,2} = \left(\sum_{m=1}^{8} w_{1,m} \left(\frac{K_{1,m}}{K_2} \right)^{0.75} \right),$$

$$M_{1,oh,3} = \left(\sum_{m=9}^{12} w_{1,m} \left(\frac{K_{1,m}}{K_3} \right)^{0.75} \right),$$

$$M_{2,pad,4} = \left(\sum_{m=1}^{9} w_{1,m} \left(\frac{K_{1,m}}{K_4} \right)^{0.75} \right),$$

and

$$M_{2,pad,5} = \left(\sum_{m=10}^{14} w_{1,m} \left(\frac{K_{1,m}}{K_5} \right)^{0.75} \right).$$

Table 10.2.2 Scaling Factor, *M*, for Liquid-immersed Distribution Transformers

EC	Phases	RU (*j*)	RepCap (KVA) (*k*)	Ownership (*p*)	Application	*M*
EC01	1	RU01	50	IOU	Pad	1.12
EC01	1	RU01	50	POU	Pad	1.12
EC01	1	RU02	25	IOU	OH	1.16
EC01	1	RU02	25	POU	OH	1.16
EC01	1	RU03	500	IOU	OH	0.77
EC01	1	RU03	500	POU	OH	0.77
EC02	3	RU04	150	IOU	Pad	1.44
EC02	3	RU04	150	IOU	OH	0.78
EC02	3	RU04	150	POU	Pad	1.44
EC02	3	RU04	150	POU	OH	0.78
EC02	3	RU05	1500	IOU	Pad	0.93
EC02	3	RU05	1500	IOU	OH	0.00
EC02	3	RU05	1500	POU	Pad	0.93
EC02	3	RU05	1500	POU	OH	0.00

Table 10.2.3 Scaling Factor, *M*, for Dry-type Distribution Transformers

EC	Phases	RU (*j*)	BIL	RepCap (KVA) (*k*)	Ownership (*p*)	Sector	M
EC03	1	RU06	10	25	ALL	C&I	1.5
EC04	3	RU07	10	75	ALL	C&I	0.9
EC04	3	RU08	10	300	ALL	C&I	1.0
EC05	1	RU09V	45	100	ALL	C&I	0.3
EC05	1	RU10V	45	500	ALL	C&I	0.7
EC06	3	RU09	45	300	ALL	C&I	1.1
EC06	3	RU10	45	1500	ALL	C&I	0.6
EC07	1	RU11V	95	100	ALL	C&I	0.3
EC07	1	RU12V	95	500	ALL	C&I	0.7
EC08	3	RU11	95	300	ALL	C&I	1.2
EC08	3	RU12	95	1500	ALL	C&I	1.2
EC09	1	RU13V	125	100	ALL	C&I	0.3
EC09	1	RU14V	125	667	ALL	C&I	0.5
EC10	3	RU13	125	300	ALL	C&I	1.3
EC10	3	RU14	125	2000	ALL	C&I	0.9

10.2.3 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 distribution transformer equipment classes, DOE often analyzed several design lines per equipment class. For single-phase, medium-voltage, dry-type design lines, equipment classes 5, 7, and 9, DOE used factors for the appropriate three-phase design lines divided by three. Table 10.2.4 presents the mapping of design line (DL) to equipment class (EC).

Table 10.2.4 Mapping of Design Line to Equipment Class

Equipment Class		BIL* *kV*	Capacity *kVA*	Mapping
1	Liquid-immersed, medium-voltage, single-phase	< 200	10–833	DL 1 + DL2 + DL3
2	Liquid-immersed, medium-voltage, three-phase	< 200	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	(DL13 + DL14)/3
10	Dry-type, medium-voltage, three-phase	> 95	225–2,500	DL13 + DL14

* 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] and publicly available data provided the weights of each capacity shipped for each representative unit and equipment class. The LCC analysis provided the economic results for each design line, and DOE used the scaling method described in section 10.2.1 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..

10.2.4 Mapping Efficiency Level to Candidate Standard Level

DOE conducted the LCC analysis for up to seven energy efficiency levels (EL) for each representative unit in the 14 design lines. DOE 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 one-to-one to candidate standard levels (CSLs) for the 10 equipment classes.

10.2.5 Load Growth

The load growth is the fraction by which the load increases after a transformer is installed. 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) Standard C57.91-1995, Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators,[8] for details on permissible electrical overloading of mineral-oil-immersed transformers. Because IEEE does not report data on permissible overloading of dry-type units, DOE used the same initial peak load for both liquid-immersed and dry-type transformers, but did not apply load growth to 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 (%), set at 0.5 percent.

aThus, 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:

$$LAdjust(y) = \sqrt{\sum_{age=1}^{y-Std_{year}} \frac{\left[Stock(y, age) \times \left(1 + LGrwth(age)\right)^2\right]}{Aff_{Stock(y)}}},$$

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 10.2.7.

10.2.6 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.

10.2.7 Annual Energy Consumption per Unit

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.

10.2.8 Site-to-Primary Energy Conversion Factor

The site-to-primary energy conversion factor is a multiplicative factor used to convert site energy consumption into primary or source energy consumption, expressed in quads. For electricity from the grid, primary energy consumption is equal to the heat content of the fuels used to generate that electricity.[b] For natural gas and fuel oil, primary energy is equivalent to site energy.

DOE used annual conversion factors based on the version of the National Energy Modeling System (NEMS)[c] that corresponds to *AEO 2021*.[1] The factors are marginal values, which represent the response of the national power system to incremental changes in consumption. The conversion factors change over time in response to projected changes in generation sources (the types of power plants projected to provide electricity). Specific

[b] For electricity sources such as nuclear energy and renewable energy, the primary energy is calculated using the convention used by EIA (see appendix 10B).

[c] 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 2018*, March 2019, https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2018).pdf

conversion factors were generated from NEMS for a number of end uses in each sector. Appendix 10B describes how DOE derived these factors.

Table 10.2.5 shows the conversion factors used for distribution transformers. DOE used an average of factors corresponding to all sectors for liquid-immersed, and all commercial and industrial sectors for dry-type.

Table 10.2.5 Site-to-Primary Conversion Factors (MMBtu primary/MWh site) Used for Distribution Transformers

	2025	2030	2035	2040	2045	2050+
Residential						
Clothes Dryers	9.484	9.258	9.257	9.205	9.153	9.133
Cooking	9.473	9.246	9.245	9.193	9.142	9.122
Freezers	9.496	9.267	9.264	9.211	9.159	9.138
Lighting	9.511	9.289	9.290	9.238	9.186	9.167
Refrigeration	9.496	9.267	9.264	9.212	9.159	9.138
Space Cooling	9.397	9.146	9.133	9.080	9.026	9.001
Space Heating	9.526	9.306	9.308	9.256	9.204	9.185
Water Heating	9.493	9.270	9.271	9.219	9.168	9.149
Other Uses	9.484	9.259	9.258	9.206	9.154	9.134
Commercial						
Cooking	9.409	9.184	9.185	9.135	9.085	9.065
Lighting	9.426	9.200	9.200	9.150	9.100	9.079
Office Equipment (Non-Pc)	9.374	9.145	9.145	9.095	9.046	9.026
Office Equipment (Pc)	9.374	9.145	9.145	9.095	9.046	9.026
Refrigeration	9.476	9.250	9.249	9.197	9.146	9.126
Space Cooling	9.378	9.125	9.111	9.058	9.005	8.979
Space Heating	9.532	9.313	9.314	9.262	9.210	9.191
Ventilation	9.478	9.253	9.252	9.200	9.149	9.129
Water Heating	9.409	9.184	9.186	9.136	9.087	9.067
Other Uses	9.389	9.161	9.162	9.111	9.062	9.042
Industrial						
All Uses	9.389	9.161	9.162	9.111	9.062	9.042

10.2.9 Full-Fuel-Cycle Multipliers

DOE uses an FFC multiplier to account for the energy consumed in extracting, processing, and transporting or distributing primary fuels, which are referred to as upstream activities. DOE developed FFC multipliers using data and projections generated for *AEO 2021*. *AEO 2021* provides extensive information about the energy system, including projections of future oil, natural gas, and coal supplies; energy use for oil and gas field and refinery operations; and fuel consumption and emissions related to electric power production. The information can be used to define a set of parameters that represent the energy intensity of energy production.

The method used to calculate FFC energy multipliers is described in appendix 10B of this TSD. The multipliers are applied to primary energy consumption. Table 10.2.6 shows the FFC energy multipliers for selected years.

Table 10.2.6 Full-Fuel-Cycle Energy Multipliers (based on AEO 2021)

	2025	2030	2035	2040	2045	2050+
Electricity	1.042	1.039	1.038	1.037	1.038	1.037

10.2.10 Rebound Effect

A rebound effect may follow an energy conservation standard if consumers increase usage of equipment because it costs less to operate than previous equipment.[d] The rebound effect reduces the energy savings attributable to a standard.[2, 3, 4, 5] Where appropriate, DOE accounts for the direct rebound effect when estimating the NES from potential standards. For distribution transformers, DOE did not consider a rebound effect.

Use of higher-efficiency equipment is occasionally associated with a direct rebound effect, which refers to an increase in utilization of the equipment due to the increase in efficiency. DOE did not find any data on the rebound effect specific to distribution transformers. Further, a rebound effect is a consumer behavior, which entails the knowledge of the higher efficiency equipment. Since that the "usage" of a distribution transformer is entirely dependent on the aggregation of the connected loads on the circuit the transformer serves, and greater usage would result in greater per-unit load on the transformer. Those connected loads, consumers, typically have no knowledge of the efficiency of the transformer that is serving them, therefore any increase in transformer usage would be is coincidental, and not related to rebound effect.

10.3 NET PRESENT VALUE

10.3.1 Definition

The NPV is the value in the present of a time-series of costs and savings. The NPV is described by the equation:

$$NPV = PVS - PVC$$

Where:

PVS = present value of operating cost savings,[e] and
PVC = present value of increased total installed costs (purchase price and any installation costs).

DOE determines the PVS and PVC according to the following expressions.

[d] This response is referred to as a direct rebound effect. It is difficult to account for economy-wide indirect rebound effects, which reflect how consumers spend the money saved by energy conservation.
[e] The operating cost includes energy, water (if relevant), repair, and maintenance.

$$PVS = \sum OCS_y \times DF_y$$
$$PVC = \sum TIC_y \times DF_y$$

Where:

OCS = total annual-savings in operating costs summed over vintages of the stock;

DF = discount factor in each year;

TIC = total annual increases in installed cost summed over vintages of the stock; and

y = year in the forecast.

DOE calculated the total annual consumer savings in operating costs by multiplying the number or stock of the transformers (by vintage) by its per-unit operating cost savings (also by vintage). DOE calculated the total annual increases in consumer product price by multiplying the number or shipments of the product (by vintage) by its per-unit increase in consumer cost (also by vintage). Total annual operating cost savings and total annual product installed cost increases are calculated by the following equations.

$$OCS_y = \sum STOCK_V \times UOCS_V$$
$$TIC_y = \sum SHIP_y \times UTIC_y$$

Where:

OCS_y = operating cost savings per unit in year y,

$STOCK_V$ = stock of transformers of vintage V that survive in the year for which DOE calculated annual energy consumption,

$UOCS_V$ = annual operating cost savings per unit of vintage V,

V = year in which the transformers was purchased as a new unit;

TIC_y = total increase in installed transformers cost in year y.

$SHIP_y$ = shipments of the transformers in year y; and

$UTIC_y$ = annual per-unit increase in installed product cost in year y.

DOE determined the total increased equipment cost for each year from 2027 to 2056. DOE determined the present value of operating cost savings for each year from 2027 to the year when all units purchased in 2056 are estimated to retire (2115). DOE calculated installed cost and operating cost savings as the difference between a standards case and a no-new-standards case. As with the calculation of NES, DOE did not use no-new-standards case shipments to calculate total annual installed costs and operating cost savings. To avoid including savings attributable to shipments displaced by consumers deciding not to buy higher-cost products, DOE used the standards-case projection of shipments and, in turn, the standards-case stock, to calculate these quantities.

DOE developed a discount factor from the national discount rate and the number of years between the “present” (year to which the sum is being discounted) and the year in which the costs and savings occur.

10.3.2 Total Installed Cost

The per-unit total installed cost is a function of product energy efficiency. Therefore, DOE used the shipments-weighted efficiencies of the no-new-standards case and standards cases described in section 10.2, in combination with the total installed costs developed in chapter 8, to estimate the shipments-weighted average annual per-unit total installed cost under the various cases. Table 10.3.1 show the shipment-weighted average total installed cost for transformers in 2027 based on the efficiencies that correspond to the no-new-standards case and each standards case.

Table 10.3.1 Shipments-Weighted Average Total Installed Cost in 2027, (2020$)

Equipment Class	No-new Standards Case	Candidate Standard Level				
		1	2	3	4	5
1	1,974	2,034	2,064	2,175	2,299	2,792
2	13,810	14,116	14,268	14,490	14,911	18,348
3	1,475	1,478	1,518	1,582	1,845	2,108
4	2,501	2,516	2,538	3,146	3,298	3,421
5	1,473	1,488	1,509	1,680	1,750	1,940
6	15,853	16,175	16,653	18,789	19,756	22,175
7	2,345	2,445	2,565	2,980	3,031	3,338
8	48,274	51,278	53,304	67,117	68,808	77,237
9	2,911	2,995	3,074	3,639	3,925	4,067
10	50,174	52,992	54,924	68,593	71,363	78,323

The total annual increase in installed cost for a given standards case is the product of the total installed cost increase per unit due to the standard and the number of units of each vintage. This approach accounts for differences in total installed cost from year to year.

10.3.3 Annual Operating Costs Savings

Per-unit annual operating costs encompass the annual costs for energy, repair, and maintenance. DOE determined the savings in per-unit annual energy cost by multiplying the savings in per-unit annual energy consumption by the appropriate energy price, and any associated costs or savings for repair and maintenance.

As described in chapter 8 of this TSD, to estimate energy prices in future years, DOE multiplied the recent electricity prices by a projection of annual national-average industrial, residential and commercial electricity prices.

The total savings in annual operating costs for an CSL is the product of the annual operating cost savings per unit under that standard and the number of units of each vintage. This approach accounts for differences in savings in annual operating costs from year to year.

10.3.4 Consideration of Rebound Effect

As previously discussed, DOE did not consider a rebound effect for distribution transformers.

10.3.5 Discount Factor

DOE multiplies monetary values in future years by a discount factor to determine present values. The discount factor (DF) is described by the equation:

$$DF = \frac{1}{(1+r)^{(y-y_P)}}$$

Where:

r = discount rate,

y = year of the monetary value, and

y_P = year in which the present value is being determined.

DOE uses both a 3-percent and a 7-percent real discount rate when estimating national impacts. Those discount rates were applied in accordance with the Office of Management and Budget (OMB)'s guidance to Federal agencies on developing regulatory analyses (OMB Circular A-4, September 17, 2003, and section E., "Identifying and Measuring Benefits and Costs," therein). DOE defined the present year as 2021.

10.3.6 Present Value of Increased Installed Costs and Savings

The present value of increased installed costs is the annual increase in installed cost for each year (*i.e.*, the difference between the standards case and no-new-standards), discounted to the present and summed over the forecast period (2027–2056). The increase in total installed cost refers to both product and installation costs associated with the higher energy efficiency of products purchased under a standards case compared to the no-new-standards case.[f] DOE

[f] For the NIA, DOE excludes sales tax from the product cost, because sales tax is essentially a transfer and therefore is more appropriate to include when estimating consumer benefits.

calculated annual increases in installed cost as the difference in total cost of new products installed each year, multiplied by the shipments in the standards case.

The present value of operating cost savings is the annual savings in operating cost (the difference between the no-new-standards case and a standards case), discounted to the present and summed over the period that begins with the expected compliance date of potential standards and ends when the last installed unit is retired from service. Savings represent decreases in operating costs associated with the higher energy efficiency of products purchased in a standards case compared to the no-new-standards case. Total annual operating cost savings are the savings per unit multiplied by the number of units of each vintage that survive in a particular year. Because a product consumes energy throughout its lifetime, the energy consumption for units installed in a given year includes energy consumed until the unit is retired from service.

10.4 RESULTS

10.4.1 National Energy Savings

This section provides NES results that DOE calculated for each CSL analyzed for transformers. NES results are shown as savings in both site and FFC energy. Because DOE based the inputs to the NIA model on weighted-average values, results are discrete point values, rather than a distribution of values as produced by the life-cycle cost and payback period analysis. National energy savings for high and low economic growth scenarios are presented in appendix 10A of this TSD.

Table 10.4.1 Cumulative National Site Energy Savings, 30 years of Shipments (2027 – 2056)

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Liquid-immersed	0.24	1.00	1.93	2.50	2.91
Low-voltage Dry-type	0.03	0.06	0.40	0.70	0.82
Medium-voltage Dry-Type 45 BIL	0.00	0.00	0.01	0.01	0.01
Medium-voltage Dry-Type 95 BIL	0.01	0.02	0.10	0.11	0.13
Medium-voltage Dry-Type 125 BIL	0.01	0.01	0.07	0.08	0.09

Table 10.4.2 Cumulative National Primary Energy, 30 years of Shipments (2027 – 2056)

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Liquid-immersed	0.42	2.01	3.93	5.03	5.54
Low-voltage Dry-type	0.04	0.07	0.53	0.93	1.08
Medium-voltage Dry-Type 45 BIL	0.00	0.00	0.01	0.01	0.01
Medium-voltage Dry-Type 95 BIL	0.01	0.02	0.11	0.12	0.14
Medium-voltage Dry-Type 125 BIL	0.01	0.01	0.08	0.08	0.10

Table 10.4.3 Cumulative National Full-fuel Cycle Energy Savings, 30 years of Shipments (2027 – 2056)

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Liquid-immersed	0.43	2.09	4.07	5.22	5.74
Low-voltage Dry-type	0.04	0.07	0.55	0.96	1.13
Medium-voltage Dry-Type 45 BIL	0.00	0.00	0.01	0.01	0.01
Medium-voltage Dry-Type 95 BIL	0.01	0.02	0.11	0.12	0.14
Medium-voltage Dry-Type 125 BIL	0.01	0.01	0.08	0.09	0.10

Table 10.4.4 Cumulative National Site Energy Savings, 9 years of Shipments (2027 – 2035)

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Liquid-immersed	0.06	0.27	0.52	0.68	0.79
Low-voltage Dry-type	0.01	0.02	0.11	0.19	0.23
Medium-voltage Dry-Type 45 BIL	0.00	0.00	0.00	0.00	0.00
Medium-voltage Dry-Type 95 BIL	0.00	0.01	0.03	0.03	0.04
Medium-voltage Dry-Type 125 BIL	0.00	0.00	0.02	0.02	0.02

Table 10.4.5 Cumulative National Primary Energy, 9 years of Shipments (2027 – 2035)

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Liquid-immersed	0.11	0.55	1.07	1.37	1.50
Low-voltage Dry-type	0.01	0.02	0.15	0.26	0.30
Medium-voltage Dry-Type 45 BIL	0.00	0.00	0.00	0.00	0.00
Medium-voltage Dry-Type 95 BIL	0.00	0.01	0.03	0.03	0.04
Medium-voltage Dry-Type 125 BIL	0.00	0.00	0.02	0.02	0.03

Table 10.4.6 Cumulative National Full-fuel Cycle Energy Savings, 9 years of Shipments (2027 – 2035)

	Candidate Standard Level				
	1	**2**	**3**	**4**	**5**
Liquid-immersed	0.12	0.57	1.11	1.42	1.56
Low-voltage Dry-type	0.01	0.02	0.15	0.27	0.31
Medium-voltage Dry-Type 45 BIL	0.00	0.00	0.00	0.00	0.00
Medium-voltage Dry-Type 95 BIL	0.00	0.01	0.03	0.03	0.04
Medium-voltage Dry-Type 125 BIL	0.00	0.00	0.02	0.02	0.03

10.4.2 Net Present Value

This section provides results of calculating the NPV of consumer benefits for each CSL considered for transformers. Results, which are cumulative, are shown as the discounted value of the net savings in dollar terms. DOE based the inputs to the NIA model on weighted-average values, yielding results that are discrete point values, rather than a distribution of values as in the LCC and payback period analysis.

Figure 10.4.1 illustrates the basic components for calculating the NPV under a specific CSL for the non-discounted annual increases in installed cost and annual savings in operating cost for transformers. The figure also shows an example of the relationships between net savings, which is the difference between the savings and costs for each year. The NPV is the difference between the cumulative annual discounted savings and the cumulative annual discounted costs.

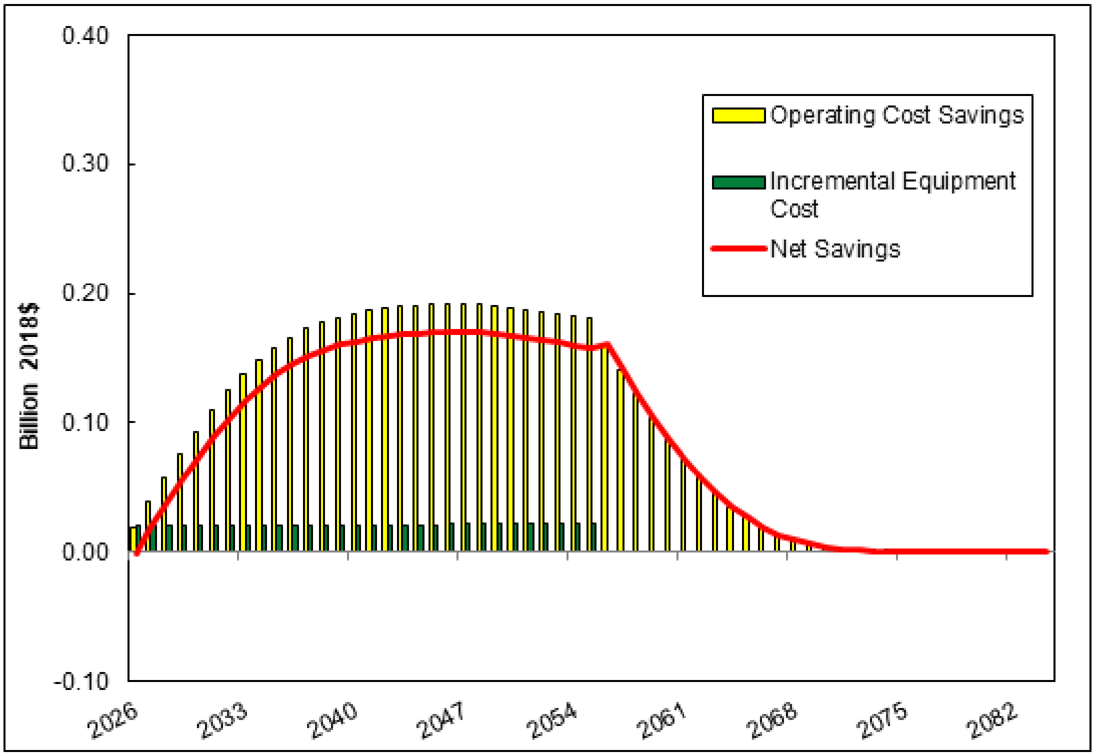


Figure 10.4.1 Example Non-Discounted Changes in Annual Installed Cost and Operating Costs for an Example Efficiency Level

Table 10.4.7 shows the results of calculating the NPV for the CSLs analyzed for transformers, at both a 3-percent and a 7-percent discount rate.

Table 10.4.7 Cumulative Consumer Net Present Value for Each Candidate Standard Level

CSL	at 3% Discount Rate, Billion 2020$	at 7% Discount Rate, Billion 2020$
Liquid-immersed		
1	0.57	(0.11)
2	1.36	(0.00)
3	2.82	0.02
4	3.90	(0.18)
5	(1.25)	(4.37)
Low-voltage Dry-type		
1	0.27	0.08
2	0.44	0.12
3	1.74	0.10
4	6.04	1.41
5	6.93	1.60
Medium-voltage Dry-Type 45 BIL		
1	0.00	0.00
2	0.00	(0.00)
3	0.04	0.01
4	0.06	0.01
5	0.05	0.00
Medium-voltage Dry-Type 95 BIL		
1	(0.03)	(0.03)
2	(0.04)	(0.05)
3	0.30	(0.04)
4	0.29	(0.05)
5	0.06	(0.19)
Medium-voltage Dry-Type 125 BIL		
1	0.01	(0.01)
2	(0.01)	(0.03)
3	0.41	0.05
4	0.41	0.04
5	0.28	(0.04)

REFERENCES

1. Hopkinson, P. & Puri, J. *Distribution Transformer Market Shipment Estimates for 2001*. (HVOLT Consultants Inc.: Washington DC, 2003).

2. Hopkinson, P. & Puri, J. *Distribution Transformer Market Shipment Estimates for 2009*. (HVOLT Consultants Inc.: Washington DC, 2010).

3. U.S Department of Commerce-Bureau of Economic Analysis *Industry Economic Accounts Information Guide. Annual industry accounts: gross domestic product (GDP) by industry*. (2018).

4. U.S. Energy Information Administration *Annual Energy Outlook 2021, With Projections to 2050*. (U.S. Department of Energy: Washington DC, 2021).

6. Energy Information Administration - Office of Integrated Analysis and Forecasting *The National Energy Modeling System (NEMS): An Overview*. (U.S. Department of Energy: Washington DC, 2019.

7. Institute of Electrical and Electronic Engineers (IEEE) *Draft Guide for Distribution Transfomer Loss Evaluation*. (IEEE: 2001).

8. Institute of Electrical and Electronic Engineers (IEEE) *Guide for Loading Mineral Oil-Immersed Transformers*. (Transformer Committee of the IEEE Power Engineering Society: 1995).

9. U.S. Office of Management and Budget *Circular A-4: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs*. (2003).

CHAPTER 11. LIFE-CYCLE COST SUBGROUP ANALYSIS

TABLE OF CONTENTS

CHAPTER 11. LIFE-CYCLE COST SUBGROUP ANALYSIS

11.1 INTRODUCTION

The consumer subgroup analysis evaluates potential impacts from new standards on any identifiable groups of consumers who may be disproportionately affected by a national energy conservation standard. When appropriate, DOE will conduct this analysis as one of the analyses for the notice of proposed rulemaking (NOPR) should DOE determine to issue a NOPR. DOE will accomplish this, in part, by analyzing the life-cycle costs (LCCs) and payback periods (PBPs) for the identified consumer subgroups. DOE will evaluate variations in regional energy prices, energy use, and installation and operational costs that might affect the impacts of a standard to consumer subgroups. To the extent possible, DOE will obtain estimates of each input parameter's variability and will consider this variability in its calculation of consumer impacts.

The Department will conduct 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 differences in operating and installation costs. The specific consumer subgroup that the Department will analyze is utilities that install distribution transformers in vaults or other space-constrained sites and utilities that server very low population densities, *i.e.* those with fewer, on average, connected customers per distribution transformer.

11.2 ANALYSIS APPROACH FOR MUNICIPAL UTILITIES AND RURAL ELECTRIC COOPERATIVES

As part of the regular life-cycle cost analysis, the Department built 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. While 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, for the NOPR analysis DOE intends to isolate these consumers for specific evaluation.

11.3 ANALYSIS APPROACH FOR PURCHASERS OF VAULT INTALLED TRANSFORMERS

DOE intends to calculate the volumes of those transformers selected by the LCC model, as a function of EL, for the two representative units (RUs) as proxies for which transformer vault constraints are most likely to be an issue: RU4 and RU5. DOE will examine the impacts of increasing transformer volume with regard to costs for vault enlargement. DOE will assume that if the volume of a transformer in a standard case is larger than the volume of the unit in the no-new standards case, above an assumed threshold, a vault modification would be warranted.

CHAPTER 12. PRELIMINARY ANALYSIS MANUFACTURER IMPACT ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

CHAPTER 12. PRELIMINARY ANALYSIS MANUFACTURER IMPACT ANALYSIS

12.1 INTRODUCTION

The purpose of the manufacturer impact analysis ("MIA") is to identify and quantify the impacts of any potential new and/or amended energy conservation standards on manufacturers. The Process Rule provides guidance for conducting this analysis with input from manufacturers and other interested parties. The U.S. Department of Energy ("DOE") will apply this methodology to its evaluation of any energy conservation standards for distribution transformers. DOE will consider a wide range of quantitative and qualitative industry impacts. For example, a particular standard level could require changes to manufacturing practices, production equipment, raw materials, *etc*. DOE will identify and analyze these manufacturer impacts during the notice of proposed rulemaking ("NOPR") stage of the analysis.

DOE announced changes to the MIA format through a report issued to Congress in January 2006 entitled "Energy Conservation Standards Activities." (as required by section 141 of the Energy Policy Act of 2005 ("EPACT 2005"))[1] Previously, DOE did not report any MIA results before the NOPR phase; however, under this new format, DOE collects, evaluates, and reports preliminary information and data.

12.2 METHODOLOGY

DOE conducts the MIA in three phases, and further tailors the analytical framework based on the comments it receives. In Phase I, DOE creates an industry profile to characterize the industry and identify important issues that require consideration. In Phase II, DOE prepares an industry cash-flow model and considers what information it might gather in manufacturer interviews. In Phase III, DOE interviews manufacturers and assesses the impacts of standards both quantitatively and qualitatively. DOE assesses industry and subgroup cash flows and industry net present value ("INPV") using the Government Regulatory Impact Model ("GRIM"). DOE then assesses impacts on competition, manufacturing capacity, employment, and cumulative regulatory burden.

12.2.1 Phase I: Industry Profile

In Phase I of the MIA, DOE collects pertinent qualitative and quantitative information about the market and manufacturer financials. This includes research and development ("R&D") expenses; selling, general, and administrative ("SG&A") expenses; capital expenditures; property, plant, and equipment expenses; tax rate; and depreciation rate for distribution transformer manufacturers, as well as wages, employment, and industry costs for distribution

---

[1] This report is available on the DOE website at *www1.eere.energy.gov/buildings/appliance_standards/pdfs/congressional_report_013106.pdf*

transformers. Sources of information include reports published by industry groups, trade journals, the U.S. Census Bureau, and Securities Exchange Commission ("SEC") 10-K filings, and prior DOE distribution transformer rulemakings. The initial estimates of financial parameters are presented in section 12.3.1.

In addition, DOE develops a comprehensive manufacturer list, develops market share estimates, and evaluates consolidation trends, as presented in the market and technology assessment. Characterizations of the current equipment offerings and market efficiency distributions are presented in the engineering analysis and shipment analysis.

12.2.2 Phase II: Industry Cash Flow Analysis and Interview Guide

Phase II activities occur after publication of the preliminary analysis. In Phase II, DOE performs a preliminary industry cash-flow analysis and prepares an interview guide for manufacturer interviews, if conducted.

12.2.2.1 Industry Cash Flow Analysis

DOE uses the GRIM to analyze the financial impacts of potential new and/or amended energy conservation standards. The implementation of these standards may require manufacturer investments, raise manufacturer production costs ("MPCs"), and/or affect revenue possibly through higher prices and lower shipments. The GRIM uses a suite factors to determine annual cash flows for the years leading up to the compliance date of new and/or amended energy conservation standards and for 30 years after implementation. These factors include industry financial parameters, annual expected revenues, costs of goods sold, SG&A expenses, taxes, and capital expenditures. Inputs to the GRIM include financial information, MPCs, shipment forecasts, and price forecasts developed in other analyses. Financial parameters are based on publicly available data and any confidentially submitted manufacturer information. DOE compares the GRIM results for potential standard levels against the results for the no-new-standards case, in which energy conservation standards are not established and/or amended. The financial impact of analyzed new and/or amended energy conservation standards is the difference between the two sets of discounted annual cash flows.

12.2.2.2 Interview Guide

When feasible, DOE conducts interviews with manufacturers to gather information on the effects new and/or amended energy conservation standards could have on revenues and finances, direct employment, capital assets, and industry competitiveness. These interviews take place during Phase III of the MIA. Before the interviews, DOE distributes an interview guide that will help identify the impacts of potential standard levels on individual manufacturers or subgroups of manufacturers within the distribution transformer industry. The interview guide covers financial parameters, MPCs, shipment projections, market share, equipment mix, conversion costs, markups and profitability, assessment of the impact on competition, manufacturing capacity, and other relevant topics.

12.2.3 Phase III: Industry and Subgroup Analysis

Phase III activities occur after publication of the preliminary analysis. These activities include manufacturer interviews, if conducted; revision of the industry cash flow analysis; manufacturer subgroup analyses, where appropriate; an assessment of the impacts on industry competition, manufacturing capacity, direct employment, and the cumulative regulatory burden; and other qualitative impacts.

12.2.3.1 Manufacturer Interviews

DOE supplements the information gathered in Phase I and the cash-flow analysis constructed in Phase II with information gathered through interviews with manufacturers and written comments from stakeholders during Phase III.

DOE conducts detailed interviews with manufacturers to gain insight into the potential impacts of any new and/or amended energy conservation standards on sales, direct employment, capital assets, and industry competitiveness. Generally, interviews are scheduled well in advance to provide every opportunity for key individuals to be available for comment. Although a written response to the questionnaire is acceptable, DOE prefers interactive interviews, if possible, which help clarify responses and provide the opportunity to identify additional issues.

A non-disclosure agreement allows DOE to consider confidential or sensitive information in the decision-making process. Confidential information, however, is not made available in the public record. At most, sensitive or confidential information may be aggregated and presented in the form of industry-wide representations.

12.2.3.2 Revised Industry Cash Flow Analysis

During interviews, DOE requests information about profitability impacts, necessary plant changes, and other manufacturing impacts. Following any such interviews, DOE revises the preliminary cash-flow prepared in Phase II based on the feedback it receives during interviews.

12.2.3.3 Manufacturer Subgroup Analysis

The use of average cost assumptions to develop an industry cash flow estimate may not adequately assess differential impacts of potential new and/or amended energy conservation standards among manufacturer subgroups. Smaller manufacturers, niche players, and manufacturers exhibiting a cost structure that differs largely from the industry average could be more negatively or positively affected. DOE customarily uses the results of the industry characterization to group manufacturers with similar characteristics. When possible, DOE discusses the potential subgroups that have been identified for the analysis in manufacturer interviews. DOE asks manufacturers and other interested parties to suggest what subgroups or characteristics are most appropriate for the analysis. One subgroup commonly identified is small business manufacturers.

12.2.3.4 Competitive Impact Assessment

EPCA directs DOE to consider the impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from a proposed standard. (42 U.S.C. 6295(o)(2)(B)(i)(V)) It also directs the Attorney General to determine the impact, if any, of any lessening of competition likely to result from a proposed standard and to transmit such determination to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6295(o)(2)(B)(ii)) Furthermore, as part of the MIA, DOE evaluates the potential impact of standards to create asymmetric cost increases for manufacturer sub-groups, shifts in competition due to proprietary technologies, and business risks due to limited supplier availability or raw material constraints.

12.2.3.5 Manufacturing Capacity Impact

One of the potential outcomes of new and/or amended energy conservation standards is the obsolescence of existing manufacturing assets, including tooling and other investments. The manufacturer interview guide has a series of questions to help identify impacts on manufacturing capacity, specifically capacity utilization and plant location decisions in the U.S. with and without new and/or amended energy conservation 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 restructuring or other charges, where applicable.

12.2.3.6 Direct Employment Impacts

The impact of potential new and/or amended energy conservation standards on direct employment is an important consideration in DOE's analysis. Manufacturer interviews aid in assessing how domestic employment patterns might be impacted by new and/or amended energy conservation standards. Typically, the interview guide contains a series of questions that are designed to explore current employment trends in the distribution transformer industry and to solicit manufacturers' views on changes in direct employment patterns that may result from increased standard levels. These questions focus on current employment levels at production facilities, expected future direct employment levels with and without changes in energy conservation standards, differences in workforce skills, and employee retraining.

12.2.3.7 Cumulative Regulatory Burden

DOE seeks to mitigate the overlapping effects on manufacturers of potential new and/or amended energy conservation standards and other Federal regulatory actions affecting the same products/equipment or companies within a short timeframe. DOE analyzes and considers the impact of multiple, equipment-specific regulatory actions on manufacturers.

12.3 PRELIMINARY FINDINGS

The following section summarizes information gathered for the preliminary MIA that are not already presented in the market and technology analysis, engineering analysis, or shipments analysis.

12.3.1 Initial Financial Parameters

For distribution transformers, DOE identified 12 publicly listed manufacturers of the distribution transformers covered by this rulemaking. Five of these publicly traded manufacturers are listed on the New York Stock Exchange, the others are listed on foreign stock exchanges. DOE chose to begin the analysis of industry financial parameters with values presented in the April 2013 Final Rule. [2] The April 2013 Final Rule financial parameters were vetted by multiple manufacturers in confidential interviews and went through public notice and comment. The results for distribution transformers are the most robust equipment-specific estimates that are publicly available. DOE compared those values with the financials of the five publicly listed companies on the New York Stock Exchange to confirm that the parameters were still relevant. DOE noted that tax rates estimates from before 2018 are not relevant for modeling future cash-flows due to the Tax Cuts and Jobs Act of 2017,[3] which was signed into law in December 2017 and changed the maximum Federal corporate tax rate from 35 percent to 21 percent. Table 12.3.1 below shows DOE's initial financial parameter estimates. DOE will further refine these values using feedback from manufacturer and public comments.

Table 12.3.1 Initial Financial Metrics

Financial Metric	Initial Estimates		
	Liquid	Medium Voltage Dry	Low Voltage Dry
Tax Rate *(% of Taxable Income)*[4]	21.0	21.0	21.0
Working Capital *(% of Revenue)*	19.4	18.0	16.0
SG&A *(% of Revenue)*	13.4	12.5	13.0
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 Property, Plant, and Equipment *(% of Revenues)*	14.4	14.4	14.4

The manufacturer selling price ("MSP") is the price manufacturers charge their first customers. The MSP equals the MPC multiplied by the manufacturer markup. The manufacturer markup covers all distribution transformer manufacturer's non-production costs (*e.g.*, SG&A, R&D, and interest) and profit. The MSP is different from the cost the end-user pays because

[2] 78 FR 23336 (April 18, 2013).

[3] www.congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf

[4] The tax rate used in the April 2013 Final Rule was 23.0 percent.

there are additional markups from entities along the distribution chain between the manufacturer and the end-user.

DOE considered the average manufacturer markup from the April 2013 Final Rule to be the most robust equipment-specific data available. DOE estimated the industry average manufacturer markup to be 1.25.

12.3.2 Manufacturer Subgroups

DOE performed a preliminary investigation into small business manufacturers as a subgroup for consideration in subsequent stages of the distribution transformer rulemaking. DOE relied on the Small Business Association ("SBA") size standards for determining the threshold for an entity to be a small business. The SBA size standards are set based on the North American Classification System ("NAICS") code. For NAICS code 335311, described as "power, distribution, and specialty transformer manufacturing," the size threshold is 750 employees for an entity to be a small business. The size threshold is based on enterprise-wide employment, which includes enterprise subsidiaries and branches, as well as unrelated establishments of the parent company.

DOE identify seven potential companies that meet the SBA definition of a small businesses and that manufacture distribution transformers in the United States. DOE will continue its investigation of small business manufacturers in future phases of the MIA through manufacturer interviews and the notice and comment process.

12.3.3 Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of several impending regulations may have significant consequences for individual manufacturers, groups of manufacturers, or entire industries. In the cumulative regulatory burden analysis, DOE considers expenditures associated with meeting other Federal, equipment-specific regulations that occur within the cumulative regulatory burden analysis timeframe. The cumulative regulatory burden analysis timeframe is a seven-year period that covers the three years before the compliance year, the compliance year, and the three years after the compliance year of any new and/or amended energy conservation standards for distribution transformers.

In the MIA's Phase III (as described in section 12.2.3 of this TSD), which is conducted prior to the NOPR publication, manufacturer interviews help DOE identify potential opportunities to coordinate regulatory actions in a manner that mitigates cumulative impacts, such as multiple successive redesigns of the same equipment with a short period of time. Some distribution transformer manufacturers might produce other products or equipment that are regulated by other DOE energy conservation standards. The exact regulations contributing to cumulative regulatory burden will be determined once a compliance date is proposed in the NOPR phase of the energy conservation standards rulemaking.

CHAPTER 13. EMISSIONS IMPACT ANALYSIS

TABLE OF CONTENTS

CHAPTER 13. EMISSIONS IMPACT ANALYSIS

13.1 OVERVIEW

The U.S. Department of Energy (DOE) conducts an emissions analysis for the notice of proposed rulemaking (NOPR) stage should DOE determine to issue a NOPR. In the emissions analysis, DOE estimates the reduction in power sector combustion emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), sulfur dioxide (SO_2), mercury (Hg), methane (CH_4) and nitrous oxide (N_2O) from potential energy conservation standards for the considered products, as well as emissions at the building site if applicable. In addition, DOE estimates emissions impacts in production activities (extracting, processing, and transporting fuels) that provide the energy inputs to power plants and for site combustion. These are referred to as "upstream" emissions. Together, these emissions account for the full-fuel-cycle (FFC). In accordance with DOE's FFC Statement of Policy (76 FR 51282 (August 18, 2011)), the FFC analysis includes impacts on emissions of methane and nitrous oxide, both of which are recognized as greenhouse gases.

DOE conducts the emissions analysis using marginal emissions factors that are primarily derived from data in the latest version of the Energy Information Administration's (EIA's) *Annual Energy Outlook* (*AEO)*, supplemented by data from other sources. EIA prepares the *AEO* using the National Energy Modeling System (NEMS).[a] Each annual version of NEMS incorporates the projected impacts of existing air quality regulations on emissions.

Site emissions of CO_2 and NO_X are estimated using emissions intensity factors from a publication of the Environmental Protection Agency (EPA).[1] Combustion emissions of CH_4 and N_2O are estimated using emissions intensity factors published by the EPA GHG Emissions Factors Hub.[b] The FFC upstream emissions are estimated based on the methodology developed by Coughlin (2013).[2] The upstream emissions include both emissions from fuel combustion during extraction, processing and transportation of fuel, and "fugitive" emissions (direct leakage to the atmosphere) of CH_4 and CO_2.

[a] For more information about NEMS, please refer to the U.S. Department of Energy, Energy Information Administration documentation. A useful summary is National Energy Modeling System: An Overview 2009, DOE/EIA-0581 (October 2009), available at: https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2009).pdf

[b] https://www.epa.gov/sites/production/files/2016-09/documents/emission-factors_nov_2015_v2.pdf

REFERENCES

1. U.S. Environmental Protection Agency. *AP-42: Compilation of Air Pollutant Emissions Factors*. 1998. Washington, D.C. (Last accessed March 31, 2021.) https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emission-factors.

2. Coughlin, K. *Projections of Full-Fuel-Cycle Energy and Emissions Metrics*. 2013. Lawrence Berkeley National Laboratory: Berkeley, CA. Report No. LBNL-6025E. (Last accessed March 31, 2021.) https://eta-publications.lbl.gov/sites/default/files/lbnl6025e_ffc.pdf.

CHAPTER 14. MONETIZATION OF EMISSIONS REDUCTIONS BENEFITS

TABLE OF CONTENTS

CHAPTER 14. MONETIZATION OF EMISSIONS REDUCTIONS BENEFITS

14.1 OVERVIEW

The U.S. Department of Energy (DOE) estimates the monetary benefits associated with the reduced emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and nitrogen oxides (NO_X) that are expected to result from the considered standard levels in the notice of proposed rulemaking (NOPR) stage, should DOE determine to issue a NOPR. To make this calculation similar to the calculation of the net present value (NPV) of consumer benefit, DOE considers the reduced emissions expected to result over the lifetime of products shipped in the projection period for each standard level.

DOE estimates the monetized benefits of the reductions in emissions of CO_2, CH_4, and N_2O by using a measure of the social cost of each pollutant. These estimates represent the monetary value of the net harm to society associated with a marginal increase in emissions of these pollutants in a given year, or the benefit of avoiding that increase. These estimates are intended to include (but are not limited to) climate-change-related changes in net agricultural productivity, human health, property damages from increased flood risk, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The social cost estimates used by DOE are consistent with the interim estimates issued by an Interagency Working Group on the Social Cost of Greenhouse Gases under Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis," 86 FR 7037 (Jan. 25, 2021).

To estimate the monetary value of reduced NO_X emissions from electricity generation attributable to the standard levels it considers, DOE uses benefit-per-ton estimates for NO_X associated with particulate matter ($PM_{2.5}$) derived from the scientific literature. DOE multiplies the NO_X emissions reduction estimated for each year by the NO_X value for that year under each discount rate. To calculate a present value of the stream of monetary values, DOE discounts the values using 3% and 7% discount rates.

CHAPTER 15. UTILITY IMPACT ANALYSIS

TABLE OF CONTENTS

CHAPTER 15. UTILITY IMPACT ANALYSIS

15.1 OVERVIEW

The U.S. Department of Energy (DOE) analyzes the changes in electric installed capacity and power generation that result for each considered trial standard level for the notice of proposed rulemaking (NOPR) stage should DOE determine to issue a NOPR.

The utility impact analysis is based on output of the DOE/Energy Information Administration (EIA)'s National Energy Modeling System (NEMS).[1] NEMS is a public domain, multi-sectored, partial equilibrium model of the U.S. energy sector. Each year, DOE/EIA uses NEMS to produce an energy forecast for the United States, the Annual Energy Outlook (AEO). The EIA publishes a reference case, which incorporates all existing energy-related policies at the time of publication, and a variety of side cases which analyze the impact of different policies, energy price and market trends.

DOE's methodology is based on results published for the most recent *Annual Energy Outlook (AEO)* Reference case, as well as a number of side cases that estimate the economy-wide impacts of changes to energy supply and demand. DOE estimates the marginal impacts of reduction in energy demand on the energy supply sector. In principle, marginal values should provide a better estimate of the actual impact of energy conservation standards. DOE uses the side cases to estimate the marginal impacts of reduced energy demand on the utility sector. These marginal factors are estimated based on the changes to electricity sector generation, installed capacity, fuel consumption and emissions in the *AEO* Reference case and various side cases. The methodology is described in more detail in K. Coughlin, "Utility Sector Impacts of Reduced Electricity Demand."[2,3]

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

REFERENCES

1. U.S. Department of Energy–Energy Information Administration. *The National Energy Modeling System: An Overview 2009*. 2009. Report No. DOE/EIA-0581(2009). (Last accessed March 31, 2021.) http://www.eia.gov/forecasts/archive/0581(2009).pdf.

2. Coughlin, K. *Utility Sector Impacts of Reduced Electricity Demand*. 2014. Lawrence Berkeley National Laboratory: Berkeley, CA. Report No. LBNL-6864E. (Last accessed March 31, 2021.) http://www.osti.gov/scitech/servlets/purl/1165372.

3. Coughlin, K. *Utility Sector Impacts of Reduced Electricity Demand: Updates to Methodology and Results*. 2019. Lawrence Berkeley National Laboratory: Berkeley, CA. Report No. LBNL-2001256. (Last accessed May 24, 2021.) https://www.osti.gov/servlets/purl/1580427/.

CHAPTER 16. EMPLOYMENT IMPACT ANALYSIS

TABLE OF CONTENTS

CHAPTER 16. EMPLOYMENT IMPACT ANALYSIS

16.1 OVERVIEW

Energy conservation standards can impact employment both directly and indirectly. Direct employment impacts are changes in the number of employees at the plants that produce the covered equipment resulting from standards, and are evaluated in the manufacturer impact analysis, as described in chapter 12 of this Technical Support Document. The employment impact analysis described in this chapter covers indirect employment impacts which may result from expenditures shifting between goods (the substitution effect) and changes in income and overall expenditure levels (the income effect) that occur due to the implementation of standards. The U.S. Department of Energy (DOE) DOE conducts this analysis in the notice of proposed rulemaking (NOPR) stage should DOE determine to issue a NOPR.

DOE expects new or amended energy conservation standards to decrease energy consumption and, therefore, reduce expenditures for energy. In turn, savings in energy expenditures may be redirected for new investment and other items. Notwithstanding, energy conservation standards may potentially increase the purchase price of equipment, including the retail price plus sales tax, and may increase installation costs.

Using an input-output model of the U.S. economy, the employment impact analysis seeks to estimate the year-to-year effect of these expenditure impacts on net national employment. DOE intends the employment impact analysis to quantify the indirect employment impacts of these expenditure changes.

To investigate the direct and indirect employment impacts, DOE uses the Pacific Northwest National Laboratory's (PNNL's) "Impact of Sector Energy Technologies" (ImSET 3.1.1) model.[1] PNNL developed ImSET, a spreadsheet model of the U.S. economy that focuses on 187 sectors most relevant to industrial, commercial, and residential building energy use, for DOE's Office of Energy Efficiency and Renewable Energy. ImSET is a special-purpose version of the U.S. Benchmark National Input-Output (I-O) model, which has been designed to estimate the national employment and income effects of energy saving technologies that are deployed by DOE's Office of Energy Efficiency and Renewable Energy. In comparison with the previous versions of the model used in earlier rulemakings, this version allows for more complete and automated analysis of the essential features of energy efficiency investments in buildings, industry, transportation, and the electric power sectors.

The ImSET software includes a computer-based I-O model with structural coefficients to characterize economic flows among the 187 sectors. ImSET's national economic I-O structure is based on the 2002 Benchmark U.S. table, specially aggregated to 187 sectors.[2]

REFERENCES

1. Roop, J. M., M. J. Scott, and R. W. Schultz. *ImSET: Impact of Sector Energy Technologies*. 2005. Pacific Northwest National Laboratory: Richland, WA. Report No. PNNL-15273. (Last accessed March 31, 2021.) http://www.pnl.gov/main/publications/external/technical_reports/PNNL-15273.pdf.

2. Lawson, A. M., K. S. Bersani, M. Fahim-Nader, and J. Guo. Benchmark Input-Output Accounts of the U. S. Economy, 1997. *Survey of Current Business*. 2002. 82 pp. 19–117.

CHAPTER 17. REGULATORY IMPACT ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

CHAPTER 17. REGULATORY IMPACT ANALYSIS

17.1 INTRODUCTION

Under appendix A to subpart C of Title 10 of the Code of Federal Regulations, Part 430, *Procedures for Consideration of New or Revised Energy Conservation Standards for Consumer Products* (Process Rule) the U.S. Department of Energy (DOE) is committed to explore non-regulatory alternatives to energy conservation standards. Accordingly, DOE will prepare a draft regulatory impact analysis pursuant to Executive Order 12866, "Regulatory Planning and Review," which will be subject to review by the Office of Management and Budget's Office of Information and Regulatory Affairs for the notice of proposed rulemaking (NOPR). Pursuant to the Process Rule, DOE has identified five major alternatives to standards that represent feasible policy options to reduce the energy consumption of distribution transformers. It will evaluate each alternative in terms of its ability to achieve significant energy savings at a reasonable cost, and will compare the effectiveness of each alternative to the effectiveness of the proposed standard.

Table 17.1.1 lists the non-regulatory means of achieving energy savings that DOE proposes to analyze. The technical support document (TSD) prepared in support of DOE's NOPR will include a complete quantitative analysis of each alternative, the methodology for which is briefly addressed below.

Table 17.1.1 Non-Regulatory Alternatives to Standards

No New Regulatory Action
Consumer Rebates
Consumer Tax Credits
Manufacturer Tax Credits
Voluntary Energy Efficiency Targets
Bulk Government Purchases

17.2 METHODOLOGY

DOE will use the national impact analysis (NIA) spreadsheet model for distribution transformers to calculate the national energy savings and the net present value (NPV) corresponding to each candidate standard. The NIA model is discussed in chapter 10 of the TSD. To compare each alternative quantitatively to the proposed energy conservation standards, DOE will need to quantify the effect of each alternative on the purchase and use of energy efficient distribution transformers. DOE will create an integrated NIA-RIA model, built upon the NIA model, where DOE will make the appropriate revisions to the inputs in the NIA models. Key inputs that DOE may revise in the NIA-RIA model are:

- Distribution transformer market shares meeting target efficiency levels (identical to the trial standard levels for the mandatory standards)

- Shipments of distribution transformers, when those are affected by the proposed energy conservation standards.

The following are the key measures of the impact of each alternative:

- *Energy use*: Cumulative energy use of equipment from the compliance date of the new standard to 2056. DOE will report electricity consumption as primary energy.
- *National energy savings*: Cumulative national energy use from the no-new-standards case projection minus the alternative-policy-case projection.
- *Net present value*: The value of future operating cost savings from the equipment bought during the period from the required compliance date of the new standard 2027 to 2056. DOE will calculate the NPV as the difference between the present value of equipment and operating expenditures (including energy) in the no-new-standards case, and the present value of expenditures under each alternative-policy case. DOE will calculate operating expenses (including energy costs) for the life of the equipment. It will discount future operating and equipment expenditures to 2021 using a 7-percent and 3-percent real discount rate.

APPENDIX 3A. CORE STEEL MARKET ANALYSIS

TABLE OF CONTENTS

LIST OF FIGURES

APPENDIX 3A. CORE STEEL MARKET ANALYSIS

3A.1 OVERVIEW

Grain-oriented electrical steel (GOES), the primary core steel used in distribution transformer cores, is a unique product. It has a high silicon content, which complicates its manufacture. It must be carefully processed, rolled to the correct thickness, and heated and cooled at controlled rates to facilitate the growth of steel grains. Electrical steel in generally, has seen an increase in capacity in recent years as other non-oriented electrical steel and cold rolled motor lamination steel have increased production to serve the electric motors industry. Regarding grain-oriented electrical steel specifically, estimates from experts in the steel industry suggest the total GOES production, as of 2019, what around 3 million metric tons (tonnes). Regarding the North American market specifically, estimates for total GOES usage ranged from around 250,000 tonnes for the US market specifically to 375,000 tonnes for all of North America. (AK Steel, Docket No. BIS-2020-0015-0075 at p. 153; WEG, Government of Canada, Docket No. BIS-2020-0015-0101 at p. 7-8; Docket No. BIS-2020-0015-0031 at p. 2). These estimates are for all GOES and not only GOES used in distribution transformers.

3A.1.1 Overall U.S. Steel Market History

Extreme volatility has characterized the U.S. steel market over the last four decades. During the 1980s and the 1990s steel mills 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.[1] 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.[2] 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.[1]

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.[3] 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 considerably.

Beginning around 2011, China transitioned from a net electrical steel importer to a net electrical steel exporter.[4] Between 2005 and 2011, an estimated 253,000 to 353,000 tonnes were imported to China. During this time, China increased its domestic capacity significantly, such that from 2016 to 2019 only about 22,000 tonnnes were imported to China annually. China also began exporting nearly 200,000 tonnes of electric steel.

Many of the imports formerly serving China, sought new markets around 2011, namely the United States. The rise in imports to the U.S. around this time hurt US steel manufacturers, such that in 2013, domestic steel stakeholders filed anti-dumping and countervailing duty petitions with the U.S. International Trade Commission.[5] The resulting investigation found that "an industry in the United States is neither materially injured nor threatened with material injury by reason of imports of grain-oriented electrical steel…to be sold in the United States at less than fair value."[5]

Beginning in 2018, the US government instituted a series of import duties on, among other items, aluminum and steel articles. Steel and aluminum articles were generally subject to respective import duties of 25% and 10% *ad valorem*[a]. 83 FR 11619; 83 FR 11625. Since March 2018, several presidential proclamations have created or modified steel and aluminum tariffs, including changes to the products covered, countries subject to the tariffs, exclusions, etc.[6] Given the recency of several publications, combined with the supply chain disruptions caused by the Covid-19 pandemic, many of the price effects that, directly or indirectly, impact the pricing of distribution transformers may still be in flux.

Another recent trend in distribution transformer manufacturing is an increase in distribution transformers importing or purchasing finished core products. The impact of electrical steel tariffs on manufacturer's costs varies widely depending on if manufacturers are purchasing raw electrical steel, and therefore either paying a 25% tariff or purchasing domestically produced steel, or if they are importing cores which, along with distribution transformer core laminations and finished transformer imports, are not subject to the tariffs. Some stakeholders have argued that this trend toward importing distribution transformer cores, primarily from Mexico and Canada, is a method of circumventing tariffs, as electrical steel sold in the global market is less expensive than domestic electrical steel. Conversely, other stakeholders commented that this

[a] *Ad valorem* tariffs are assessed in proportion to an item's monetary value.

trend predated the electrical steel tariffs and is consistent with the general trend of offshoring certain manufacturing businesses.

On May 19, 2020, the U.S. Department of Commerce opened an investigation into the potential circumvention of tariffs via imports of finished distribution transformer cores and lamination but has not yet released the results of that investigation and no trade action has been taken. 85 FR 29926

3A.1.2 U.S. Electrical Steel Market Key Players

Cleveland-Cliffs Inc. ("Cliffs") entered the US grain-oriented electrical steel market in 2020 through purchase of AK Steel[b]. Cliffs is the single domestic manufacturer of grain-oriented electrical steel. Formerly, Allegheny Technologies Incorporated ("ATI") also manufactured electrical steel in the United States but ceased production in 2016.[c]

Cliffs produces a range of electrical steels, including convention GOES grades, non-oriented electrical steel grades, domain-refined, and domain-refined laser scribed electrical steel grades.

Metglas, Inc. ("Metglas") is a subsidiary of Hitachi, which is headquartered in Tokyo, Japan, and a 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 than 45,000 tonnes from its U.S. facility. (Metglas, No. 11 at p. 3-4) Several additional amorphous metal producers are based in China and have begun exporting to the US market.

Other key participants in the U.S. core steel market include core steel wholesalers and processors. National Material 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., 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.2 ELECTRICAL STEEL QUALITY

3A.2.1 Conventional Electrical Steel Quality

In the previous decade, distribution transformers manufacturers have sought higher efficiency core steels in an effort to meet mandatory efficiency standards and voluntary energy efficiency goals. This demand has encouraged electrical steel producers to produce low loss core steels in higher volumes, particularly high-permeability steels and domain-refined, high-permeability steels, as opposed to conventional GOES. Figure 3A.4.1 shows the shift in

[b] In 2020, Cleveland-Cliffs Inc. acquired AK Steel.
[c] http://ir.atimetals.com/~/media/Files/A/ATIMetals-IR/annual-reports/ati2016ar.pdf

customer steel demand for high-permeability and amorphous steel grades as compared to conventional GOES from 2010 through 2019.

This shift toward higher-permeability grades of GOES suggests that from a global perspective, there are fewer barriers to using lower-core loss steels than there were during the April 2013 Final Rule. However, given the aforementioned electrical steel tariffs, some manufacturers may be limited to only grades of steel available from domestic steel manufacturers or subject to 25 percent price increases to import higher grades of steels.

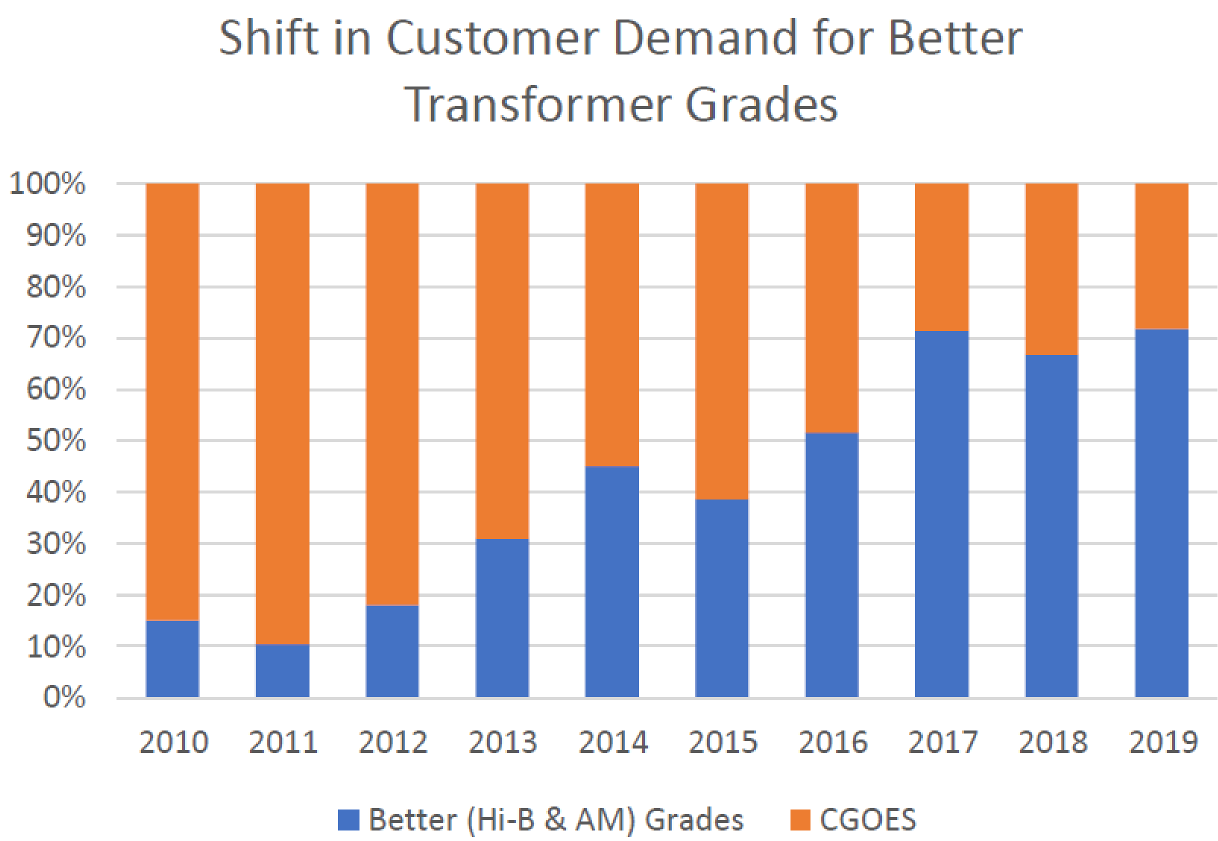


Figure 3A.4.1 Shift in Customer Steel Demand[7]

In addition to an increase in customer demand for high-efficiency GOES, there has also been a notable increase in the high-end quality of GOES available for both wound and stacked cores. Stakeholders identified laser domain-refined, high-permeability grain-oriented electrical steels with a guaranteed core loss of 70 W/kg at 1.7T and 50 Hz available on the market today for use in stacked core applications.[7] In the April 2013 Final Rule, the lowest loss GOES used in DOE’s analysis had a guaranteed core loss 80 W/kg at 1.7T and 50 Hz, indicating that significant progress in less than a decade. 78 FR 23335. Regarding wound core distribution transformers, stakeholder identified heat-proof, permanently domain-refined, high-permeability GOES with a guaranteed core loss of 75 W/kg at 1.7T and 50 Hz.[7] In the April 2013 Final Rule, the lowest loss GOES used in DOE’s analysis had a guaranteed core loss 85 W/kg at 1.7T and 50 Hz. 78 FR 23335.

3A.3 ELECTRICAL STEEL PRICING

While the price of steel often moves with the commodity market, electrical steel tends to move separately and independently. Manufacturers stressed that the price of electrical steel is largely based on annual contracts. And, for a given steel grade, the price can vary widely between manufacturers depending on the electrical steel supplier, quantity ordered, and other contract specifications.

3A.3.1 U.S. Electrical Steel Pricing

As mentioned above, there is currently only one domestic producer of GOES. Manufacturers have claimed that the prices of GOES in the global market are 25 percent or more below the prices of domestic GOES. They have claimed that even with the 25 percent tariffs, foreign manufactured steel is sometimes cheaper.[8] This can lead to dramatically different GOES prices depending on if a manufacturers is using domestic steel, imported foreign steel, or if they are importing products made of foreign steel (which are not subject to tariffs).

Manufacturers who produce their own distribution transformer cores domestically have limited options in regards to electrical steel suppliers. They could supply all of their GOES from the single domestic supplier of GOES, however, this supplier does not currently have the capacity to produce high-permeability electrical steel in sufficient quantities to supply the US market.[9] As such, these manufacturers would be limited to primarily conventional grain-oriented electrical steel and be subject to prices above what foreign competitors are paying.

Alternatively, these manufacturers could pay a 25 percent tariff and import GOES. They could also begin importing distribution transformer cores, which would not be subject to tariffs. However, this would result in significant capital in core manufacturing equipment going unused. Lastly, they could transition to amorphous steel, which is also available domestically, however, would require significant capital investment to transition their current GOES core production to amorphous and would still be reliant on a single domestic producer.

Through market research and conversations with manufacturers, DOE has learned that companies have been able to partially mitigate the impacts of the tariffs, such that prices for steel has not gone up 25 percent across the board. In the preliminary analysis, DOE assumed the average electrical steel price was reflective of an 18.8 percent increase in price relative to what the foreign price would be. However, certain manufacturers may be paying significantly more or less than this depending on their particular supply chains.

In the amorphous steel market, there has been a similar trend toward increased foreign suppliers. Prior to tariffs, stakeholders commented that as much as 50 percent of amorphous distribution transformers used foreign steel. (NEMA, No. 13 at p. 5) Metglas commented that imports from China have driven prices of amorphous steel down. (Metglas, No. 11 at p. 2) Similar options exist for those manufacturing amorphous cores in that they can either use domestic steel and pay the higher prices, pay the tariff to import foreign steel or import finished cores to avoid paying the tariffs. DOE applied an identical price increase for amorphous cores of 18.8 percent.

3A.3.2 Material Price Sensitivity Analysis

Future, prices are somewhat uncertain given the potential for future trade action, the possibility of the sole domestic producer of GOES exiting the market, as they have commented they might[10], and ongoing supply chain uncertainties associated with the Covid-19 pandemic.

It is unclear the extent to which tariffs, and the way manufacturers respond to tariffs will impact future prices of electrical steel. As mentioned, on May 19, 2020, the U.S. Department of Commerce opened an investigation into the potential circumvention of tariffs via imports of finished distribution transformer cores and lamination but has not yet released the results of that investigation and no trade action has been taken. 85 FR 29926 To account for the possibility that tariffs are expanded, DOE included a sensitivity analysis in which the 25 percent tariff applied to all electrical steel prices. Alternatively, it is possible that tariffs are either lifted or manufacturers shift production outside the US such that their products are not subject to tariffs. To account for this possibility, DOE conducted an analysis without tariffs.

3A.4 ELECTRICAL STEEL MANUFACTURER PROFILES

DOE has outlined some of the major global electrical steel manufacturers.

3A.4.1 Cleveland-Cliffs Inc. (Formerly AK Steel)

In March 2020, Cliffs testified that approximately 1400 workers are employed in the production of electrical steel across two locations in Ohio and Pennsylvania.[d] Cliffs entered the domestic electrical steel manufacturing business when it acquired AK steel in 2020. Cliffs is North America's largest producer of iron ore pallets and through the acquisition now produce flat rolled carbon, stainless, and electrical steel products. Cliffs electrical steels include: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES; and (4) non-heat proof, laser domain refined, high-permeability GOES. In 2019, then-AK Steel claimed they has capacity to produce approximately 250,000 short tons of GOES.[e]

3A.4.2 ATI

ATI Corporation, headquartered in Pittsburgh, PA operates specialty metals manufacturing facilities in Pennsylvania, Connecticut, Massachusetts, Indiana, and Ohio. ATI formerly produced conventional GOES. However, in 2016 they ceased production of GOES and exited the GOES market.

3A.4.3 Nippon Steel Corporation

In 1970, Yawata Iron and Steel and Fuji Steel merged to form Nippon Steel Corporation. Headquartered in Tokyo, Japan, Nippon Steel has about 26,570 employees[11] and produced an estimated 41 million tonnes of steel in 2020.[12] Nippon is Japan's top steelmaker, producing about 47% of the Japan's crude steels. Nippon produces a range of electrical steels including: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES; (4)

[d] (AK Steel, Docket No. BIS-2020-0015-0075, p. 77)
[e] (AK Steel, Docket No. BIS-2020-0015-0075, p. 87)

non-heat proof, laser domain refined, high-permeability GOES; and (5) heat-proof, permanently domain-refined, high-permeability GOES.

3A.4.4 JFE Steel Corporation

Another Japanese company, JFE Steel Corporation, was formed in December 2001 through a merger of Kawasaki Steel and NKK Corporation. It is a subsidiary of JFE Holdings. JFE Steel Corporation has about 45,844 employees and produced a total of 28.09 million tonnes of crude steel in 2019.[13] JFE Steel produces a range of electrical steels including: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES; (4) non-heat proof, laser domain refined, high-permeability GOES; and (5) heat-proof, permanently domain-refined, high-permeability GOES. In 2019, JFE acquired the Canada based electrical steel processing company, Cogent Power Inc., from Tata Steel.[14]

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 one of the largest steel sheet producers in Russia, with operations in Russia, the USA and the EU. In 2020 NMLK sold over 14.2 million metric tons of crude steel including 0.3 million metric tons of both non-oriented electrical steel and GOES.[15] NMLK produces a range of electrical steels including: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES; and (4) non-heat proof, laser domain refined, high-permeability GOES.

3A.4.6 Metglas (Hitachi)

Metglas is a subsidiary of Hitachi, which is headquartered in Tokyo, Japan, and is the major global supplier of amorphous ribbon. The company operates a U.S. plant in South Carolina. As of 2015, Metglas had an installed capacity of 45,000 metric tons annually from its United States production facility and 100,000 metric tons globally.[16] Metglas offers a range of amorphous electrical steels including: (1) traditional amorphous steel; (2) high-permeability amorphous steel; and (3) in 2020 Metglas launched domain-refined, high-permeability amorphous metal.[17]

3A.4.7 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. TKES produces a range of electrical steels including: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES and (4) non-heat proof, laser domain refined, high-permeability GOES. TKES is headquartered in Essen, Germany and has plants in Germany, India, Deutschland, Italy and France. ThyssenKrupp produces approximately 11 million tonnes of electrical steel annually, making it one of the largest electrical steel producer in Europe.[18]

3A.4.8 Pohang Iron and Steel (POSCO)

POSCO, located in the port city of Pohang, South Korea, was founded in 1958, produced 41 million tonnes of steel annually.[19] POSO has grown to become a global business with production and sales in 53 countries in the world. POSCO produces a range of electrical steels including: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES; (4) non-heat proof, laser domain refined, high-permeability GOES; and (5) heat-proof, permanently domain-refined, high-permeability GOES.

3A.4.9 China Baowu Steel Group (Baowu)

In February 2017, Baosteel merged with Wuhan Iron and Steel Company (WISCO) to form Baowu, making them the largest steelmaker in China.[20] Boawu produces a range of electrical steels including: (1) non-oriented electrical steel grades; (2) conventional GOES; (3) high-permeability GOES; and (4) non-heat proof, laser domain refined, high-permeability GOES. Baowu is the world's largest steel producer with an annual production capacity of over 115 million tonnes.[12]

3A.4.10 Big River Steel (BRS)

BRS, founded in 2014 and headquartered in northeast Arkansas, employs about 647 people. They are a subsidiary of U.S. Steel. Big River Big River Steel recently began producing cold rolled motor lamination electrical steel and claims their mill has the infrastructure to add fully processed non-oriented and grain-oriented electrical steel and high-permeability, grain-oriented electrical steel in the future.[21]

REFERENCES

1 U.S. Department of Commerce - International Trade Administration, *Global Steel Trade: Structural Problems and Future Solutions, Chapter 2: The U.S. Steel Import Crisis*, 2000, Washington D.C.

2 Association for Iron & Steel Technology. *Steel Industry Bankruptcies: Bankruptcy filings and other major events, 1998-2003*, 2003. (Last accessed August 8, 2005.) <http://www.steelnews.org/companies/steel_bankruptcies.htm>. This material is available in Docket # 83. Contact Ms. Brenda Edwards-Jones, U.S. Department of Energy, Building Technologies Program, Mailstop EE-2J, 1000 Independence Avenue, SW, Washington, DC, 20585-0121, telephone (202) 586-2945 for more information.

3 MEPS. *Steel Capacity Utilisation Starting to Rise*, 2009. (Last accessed September 16, 2010.) <http://www.meps.co.uk/steelcapacitynews.htm>.

4 Capital Trade Incorporated, *Effective Trade Relief on Transformer Cores and Laminations*, 2020. Submitted as part of AK Steel comment at Docket No. BIS-2020-0015-0075 at p. 168.

5 U.S. International Trade Commission, *Grain-Oriented Electrical Steel from Germany, Japan, and Poland*, Investigation Nos. 731-TA-1233, 1234, and 1236. September 2014.

6 Congressional Research Service, *Section 232 Investigations: Overview and Issues for Congress*, May 18, 2021, Available online at: https://fas.org/sgp/crs/misc/R45249.pdf

7 Cogent Power, Docket No. BIS-2020-0015-0103 at p. 6-7

8 Core Coalition, Docket No. BIS-2020-0015-0085 at p. 5

9 AK Steel, Docket No. BIS-2020-0015-0112 at p. 21

10 AK Steel, Docket No. BIS-2020-0015-0115 at p. 9

11 Nippon Steel, *Securing of Personnel*, (Last accessed August 03, 2021), Available online at: https://www.nipponsteel.com/en/csr/employees/human.html

12 World Steel Association, *Top Steel-Producing Companies 2020*, 2020 (Last accessed August 03, 2021) Available online at: https://www.worldsteel.org/steel-by-topic/statistics/top-producers.html

13 JFE, *JFE Group Report 2020*, 2020. (Last accessed on August 03, 2021), Available online at: http://www.jfe-holdings.co.jp/en/investor/library/group-report/2020/pdf/all_A4.pdf

14 JFE Shoji Trade Corporation, *Acquisition of Electrical Steel Processing Company in Canada*, 2019, (Last accessed on August 03, 2021), Available online at: https://www.jfe-shoji.co.jp/en/wp-content/uploads/sites/7/2019/09/edb9c03cf739e6a7a3499bc12ec176ed.pdf

15 Novolipetsk Steel, *2020 Annual Report*, 2021. (Last accessed on August 03, 2021), Available online at: https://nlmk.com/en/ir/reporting-center/annual-reports/

16 Metglas, Inc., Docket No. EERE-2019-BT-STD-0018-0011, p. 3-4.

17 Metglas, Inc., *Metglas HB1M-LL Transformer Core Alloy*, 2020. (Last accessed on August 03, 2021). Available at: https://metglas.com/metglas-launches-a-new-domain-refined-amorphous-metal/

18 ThyssenKrupp Steel, *Our Company – an Overview*, (Last accessed on August 03, 2021), Available online at: https://www.thyssenkrupp-steel.com/en/company/

19 Posco, *About POSCO*, (Last accessed on August 03, 2021), Available online at: https://www.posco.co.kr/homepage/docs/eng6/jsp/company/posco/s91a1000060c.jsp

20 BaoSteel, *Baosteel Co., Ltd. Consolidated by Merger with WISCO,Crude Steel Production Volume after Consolidation was Ranked Top 3 among Global Listed Steel Enterprises*, 2016, (Last accessed on August 03, 2021), Available online at: https://www.baosteel.com/group_en/contents/2863/93962.html

21 Big River Steel, *Electrical*, (Last accessed on August 3, 2021). Available online at: https://bigriversteel.com/products/electrical

APPENDIX 5A. ADDITIONAL ENGINEERING ANALYSIS RESULTS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

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. These results include the following:

1. No-load losses versus manufacturer's selling price
2. Load-losses versus manufacturer's selling price
3. Transformer weight versus efficiency

Error! Reference source not found. is reproduced from chapter 5 for reference, and provides a summary of the engineering representative units.

Table 5A.1.1 Engineering Representative Units (RUs) for Analysis

RU	EC	Group	Phase Count	kVA	BIL (kV)	Primary (kV)	Secondary (V)	Rise (°C)	Shape
1	1	LI	1	50	95	14.4	240/120V	65	Rectangular
2		LI	1	25	125	14.4	120/240V	65	Round
3		LI	1	500	150	14.4	277V	65	Round
4	2	LI	3	150	95	12.47Y/7.2	208Y/120	65	Rectangular
5		LI	3	1500	125	29.4GrdY/14.4	480Y/277	65	Rectangular
6	3	LVDT	1	25	10	.48	120/240V	150	Rectangular
7	4	LVDT	3	75	10	.48	208Y/120	150	Rectangular
8		LVDT	3	300	10	.48	208Y/120	150	Rectangular
9	6	MVDT	3	300	45	4.16	480Y/277	150	Rectangular
10		MVDT	3	1500	45	4.16	480Y/277	150	Rectangular
11	8	MVDT	3	300	95	12.47	480Y/277	150	Rectangular
12		MVDT	3	1500	95	4.16	480Y/277	150	Rectangular
13	10	MVDT	3	300	125	4.16	480Y/277	150	Rectangular
14		MVDT	3	2000	125	4.16	480Y/277	150	Rectangular

* "EC" stands for "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.
** All representative units are designed for operation at 60 Hz

5A.2 REPRESENTATIVE UNITS

5A.2.1 Representative Unit 1

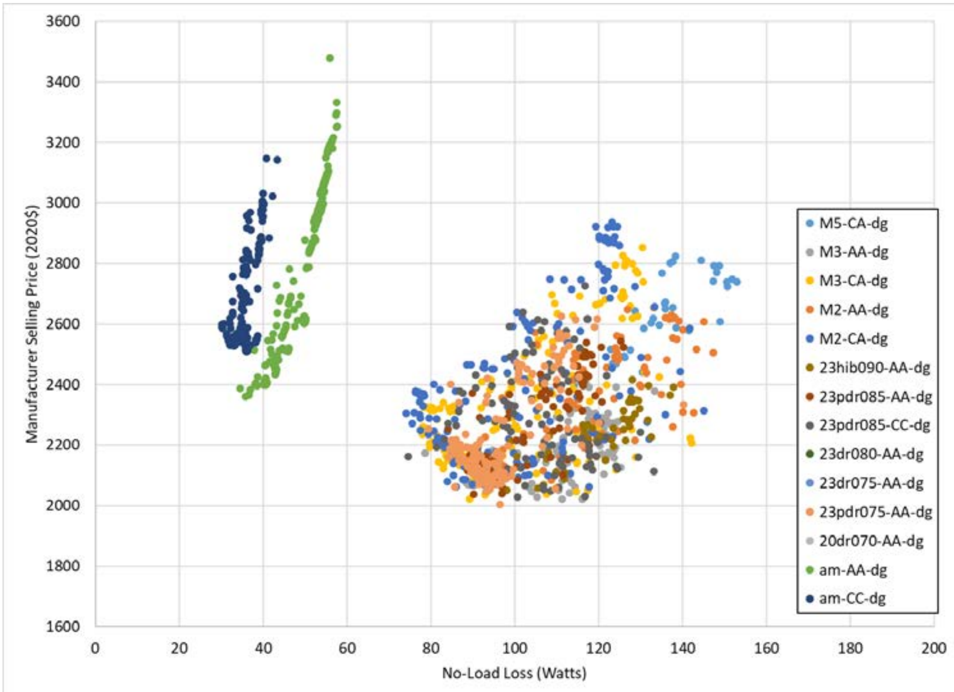


Figure 5A.2.1 Plot of Manufacturer Selling Price and No-Load Loss for RU1

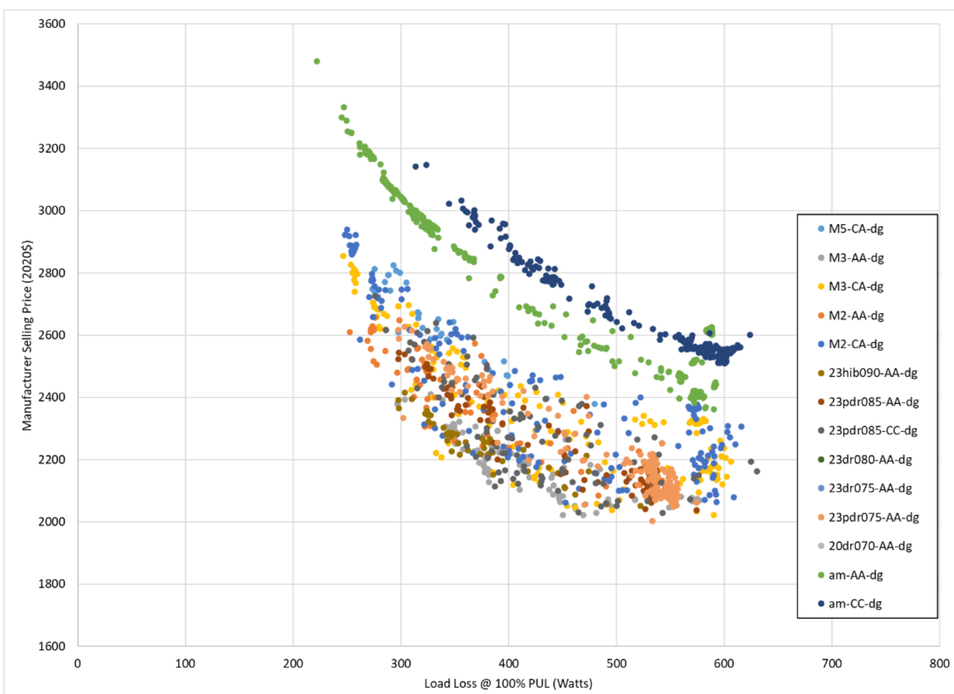


Figure 5A.2.2 Plot of Manufacturer Selling Price and Load Loss for RU1

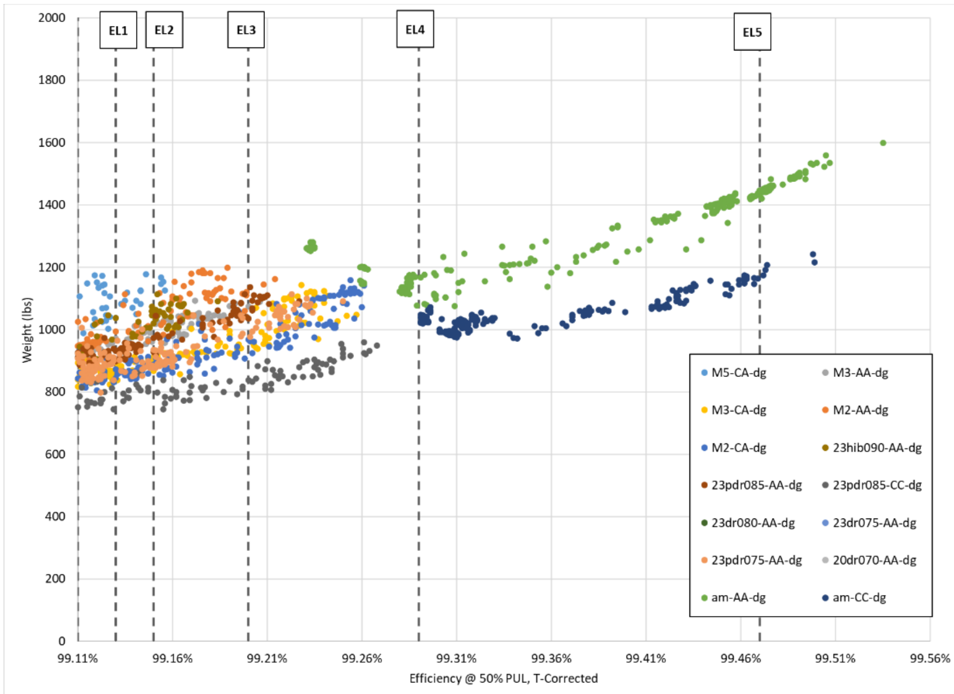


Figure 5A.2.3 Plot of Weight and Efficiency for RU1

5A.2.2 Representative Unit 2

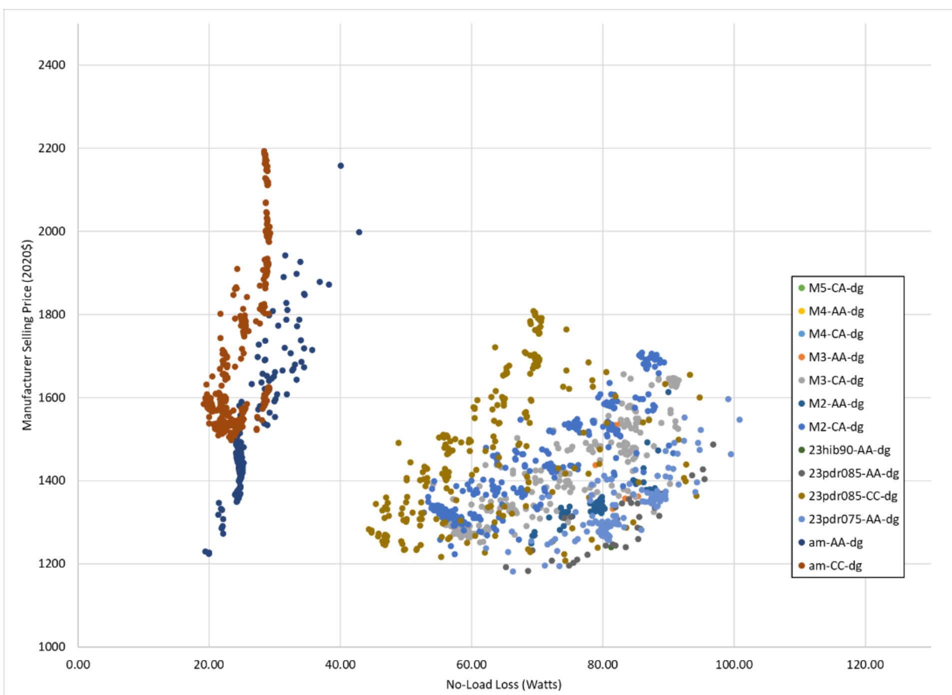


Figure 5A.2.4 Plot of Manufacturer Selling Price and No-Load Loss for RU2

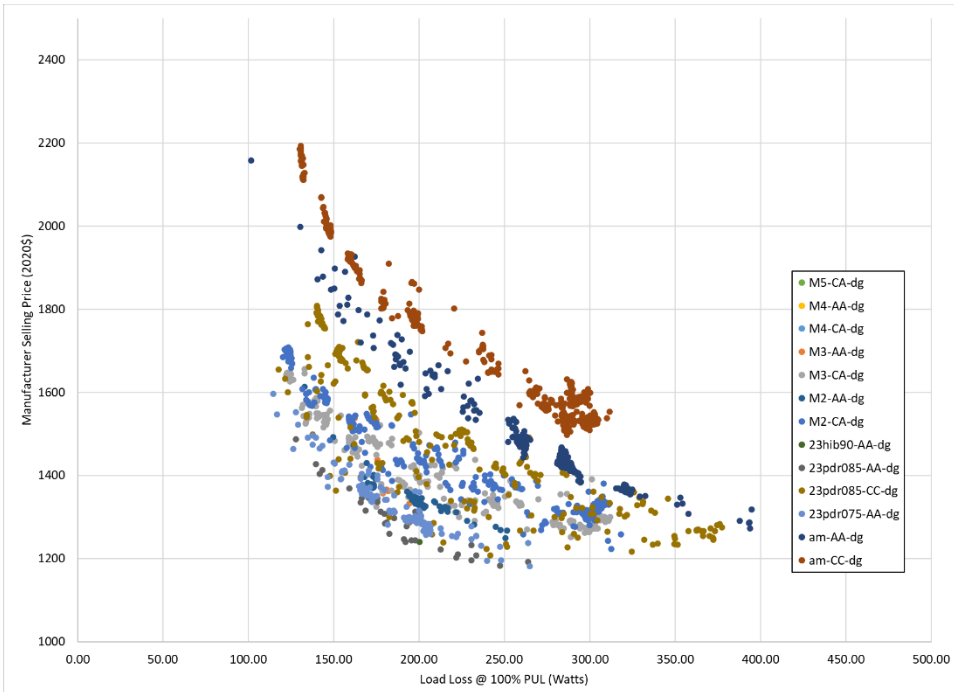


Figure 5A.2.5 Plot of Manufacturer Selling Price and Load Loss for RU2

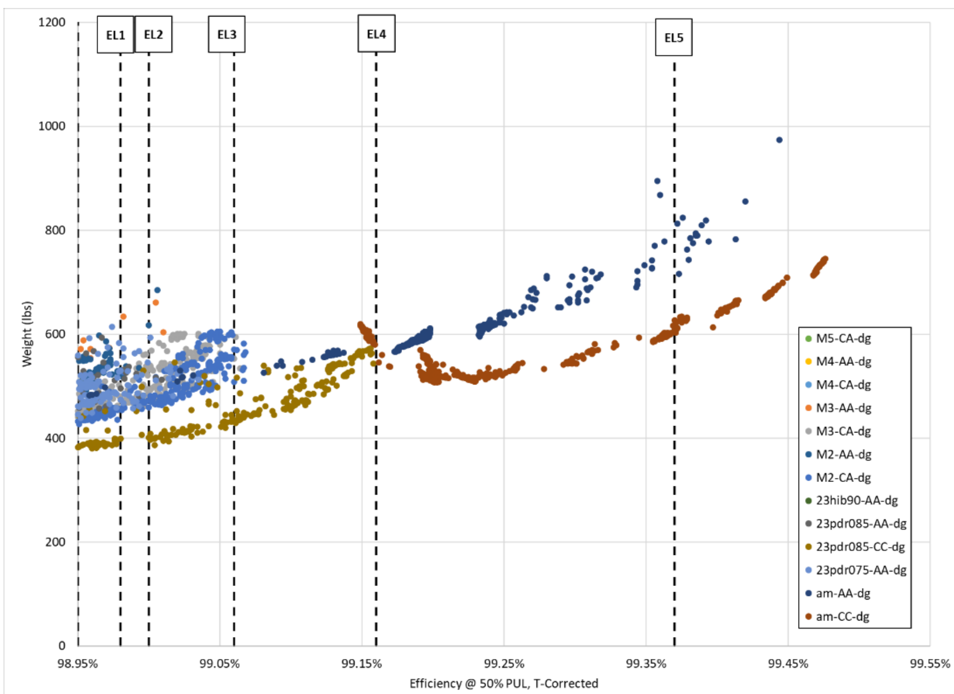


Figure 5A.2.6 Plot of Weight and Efficiency for RU2

5A.2.3 Representative Unit 3

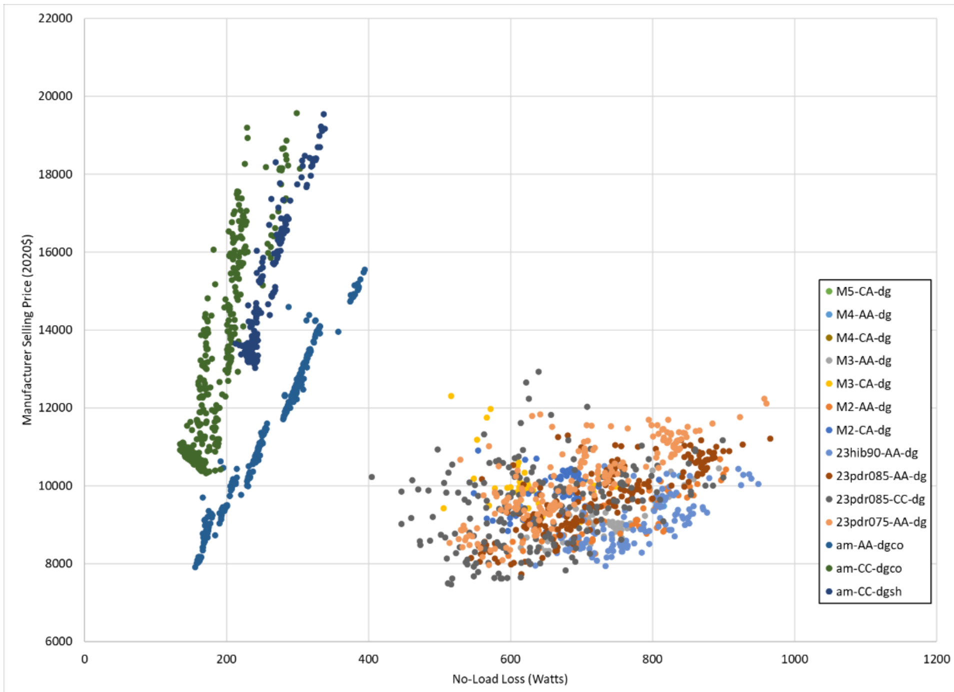


Figure 5A.2.7 Plot of Manufacturer Selling Price and No-Load Loss for RU3

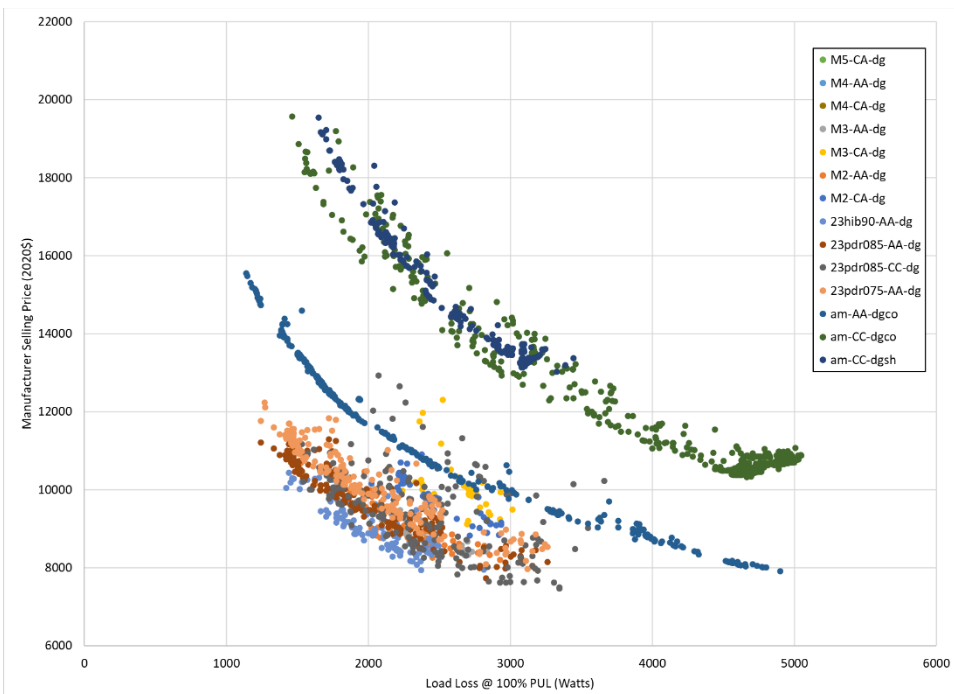


Figure 5A.2.8 Plot of Manufacturer Selling Price and Load Loss for RU3

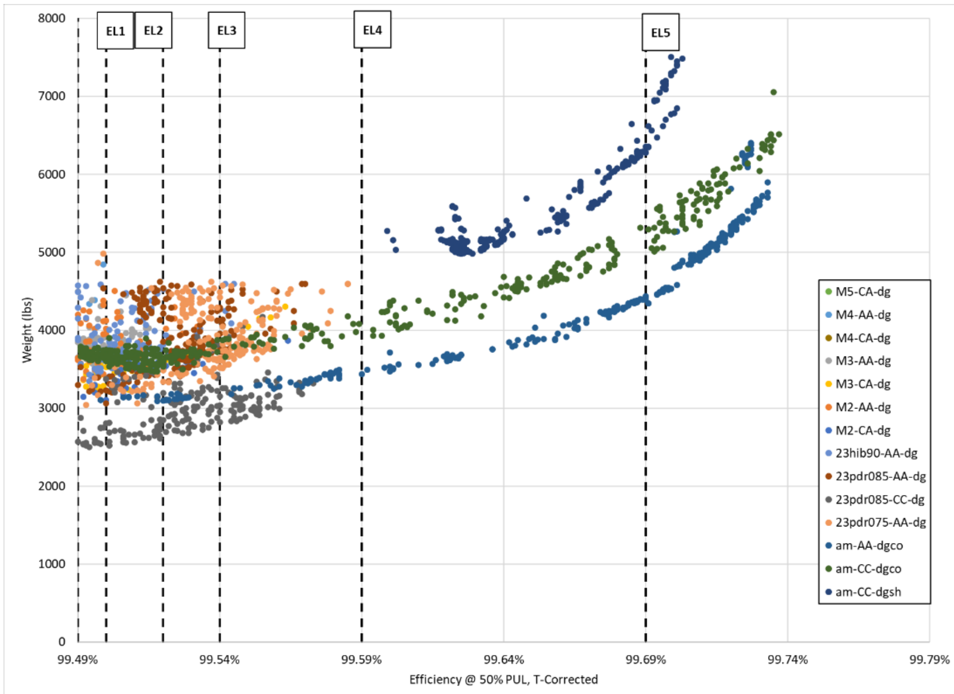


Figure 5A.2.9 Plot of Weight and Efficiency for RU3

5A.2.4 Representative Unit 4

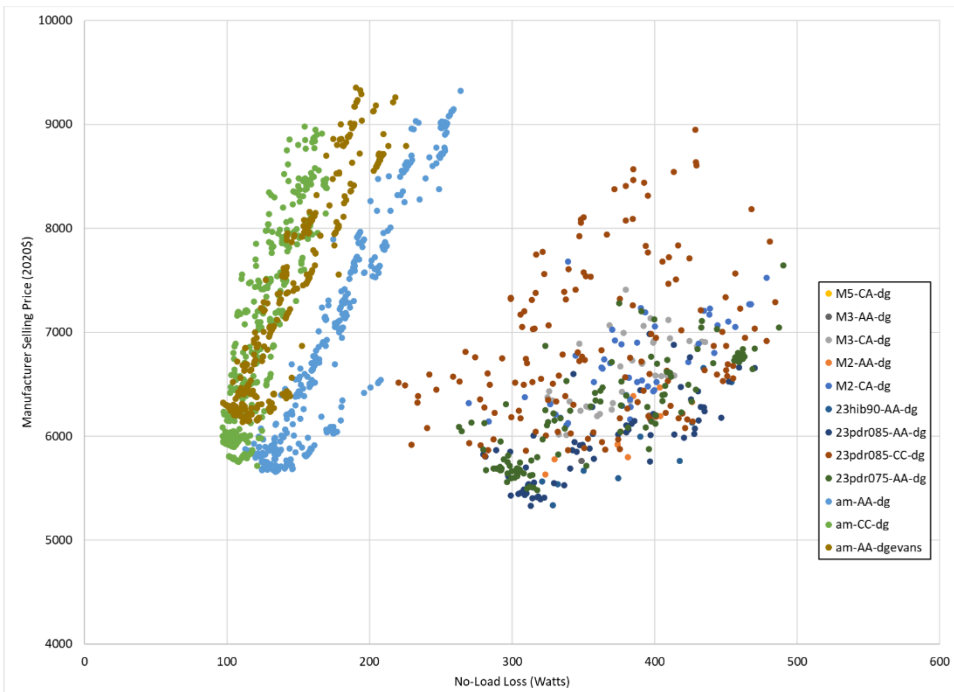


Figure 5A.2.10 Plot of Manufacturer Selling Price and No-Load Loss for RU4

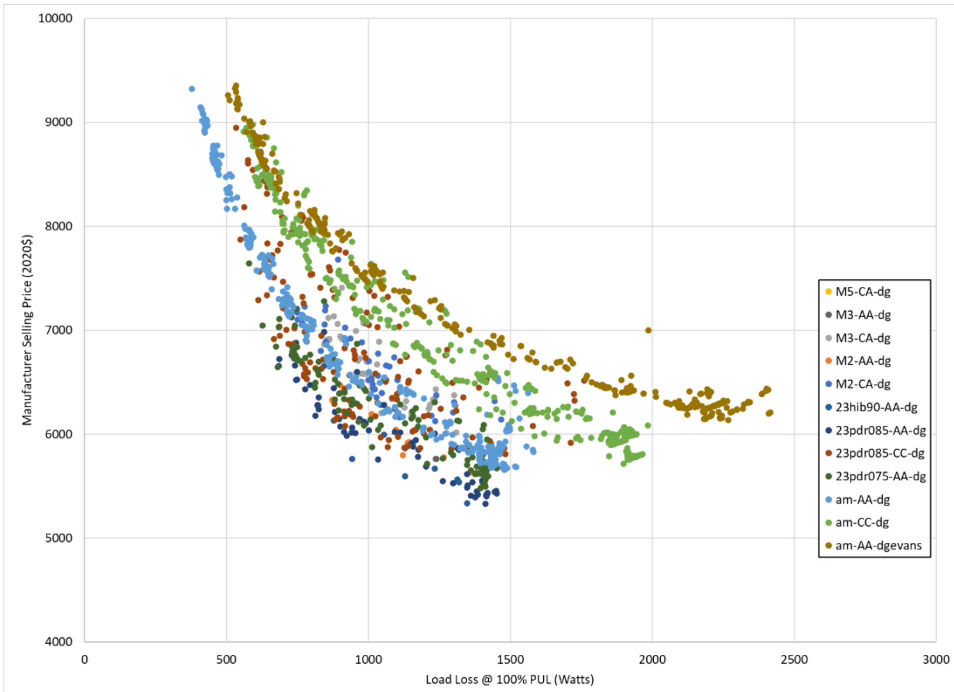


Figure 5A.2.11 Plot of Manufacturer Selling Price and Load Loss for RU4

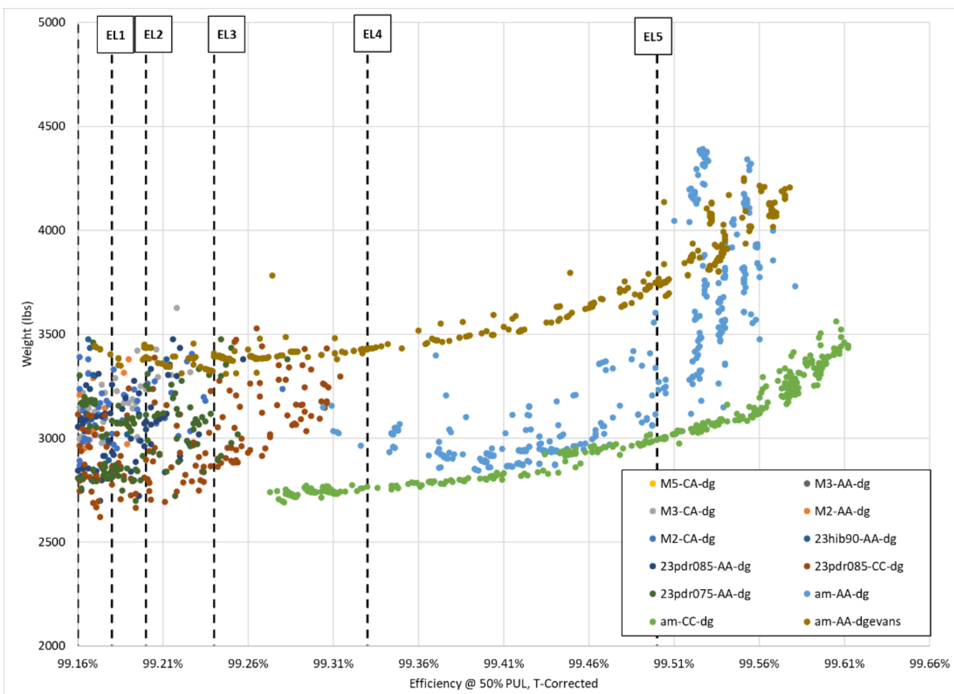


Figure 5A.2.12 Plot of Weight and Efficiency for RU4

5A.2.5 Representative Unit 5

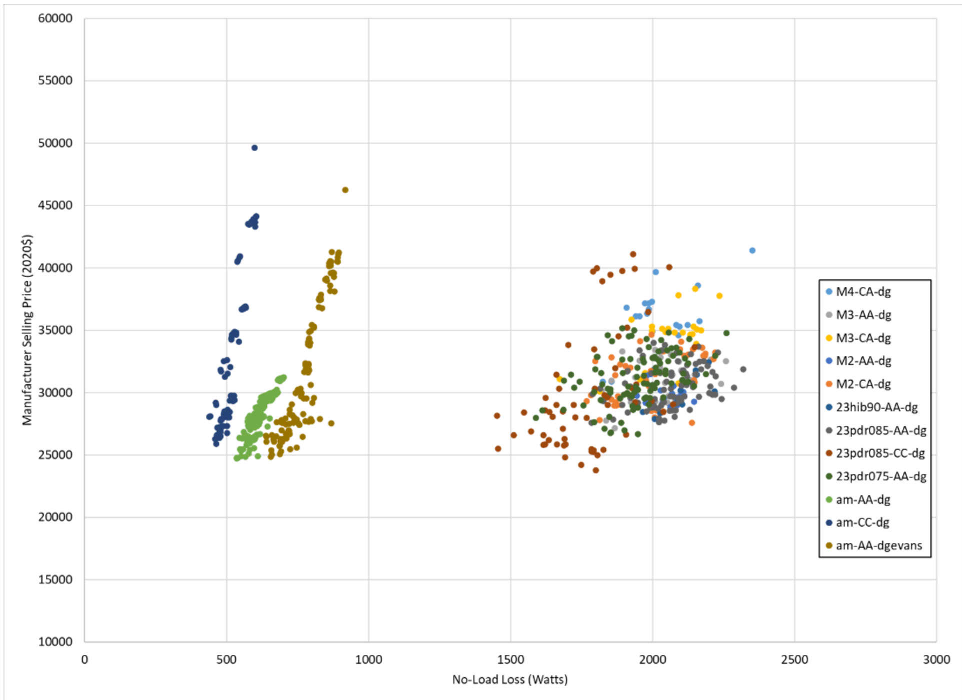


Figure 5A.2.13 Plot of Manufacturer Selling Price and No-Load Loss for RU5

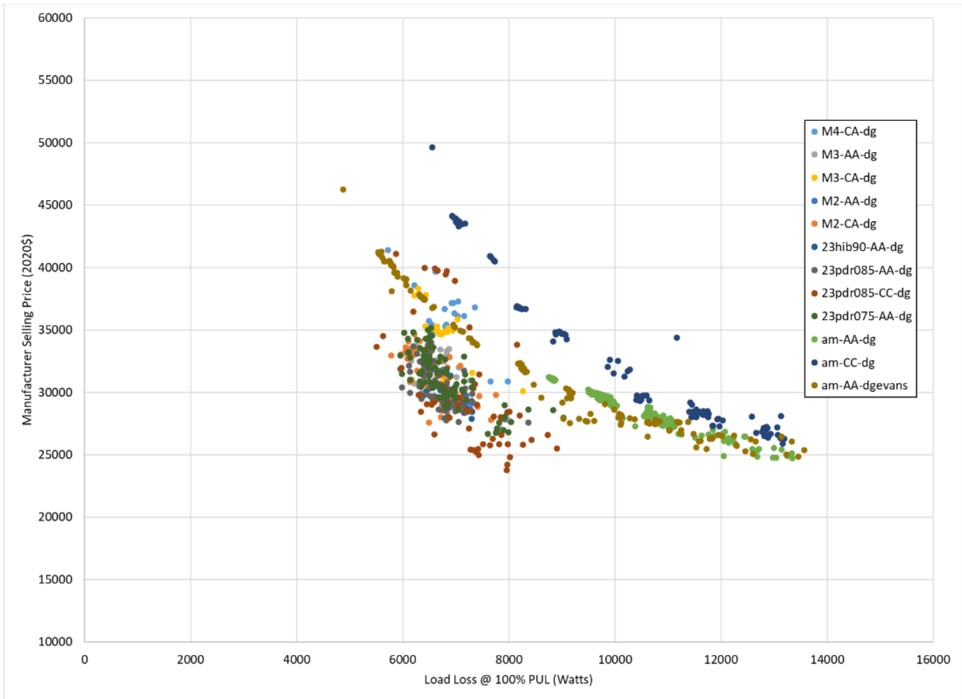


Figure 5A.2.14 Plot of Manufacturer Selling Price and Load Loss for RU5

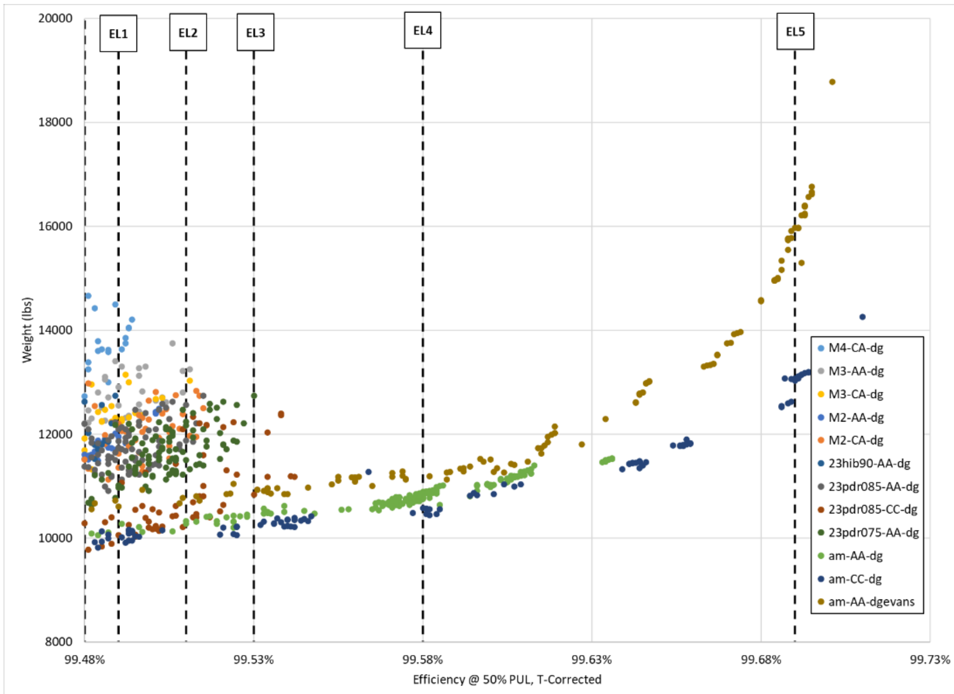


Figure 5A.2.15 Plot of Weight and Efficiency for RU5

5A.2.6 Representative Unit 6

Figure 5A.2.16 Plot of Manufacturer Selling Price and No-Load Loss for RU6

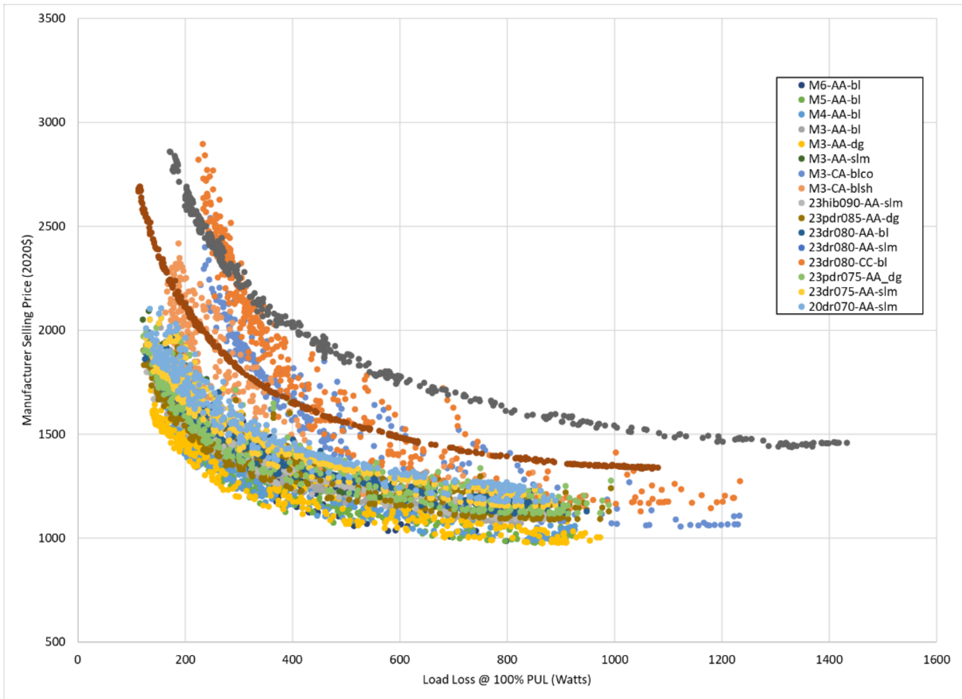


Figure 5A.2.17 Plot of Manufacturer Selling Price and Load Loss for RU6

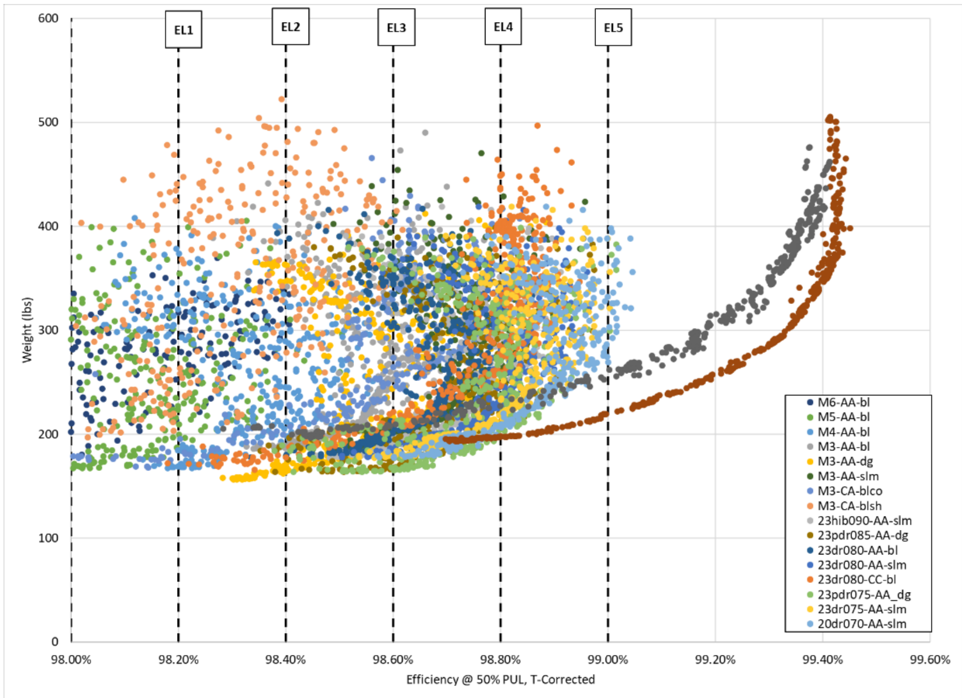


Figure 5A.2.18 Plot of Weight and Efficiency for RU6

5A.2.7 Representative Unit 7

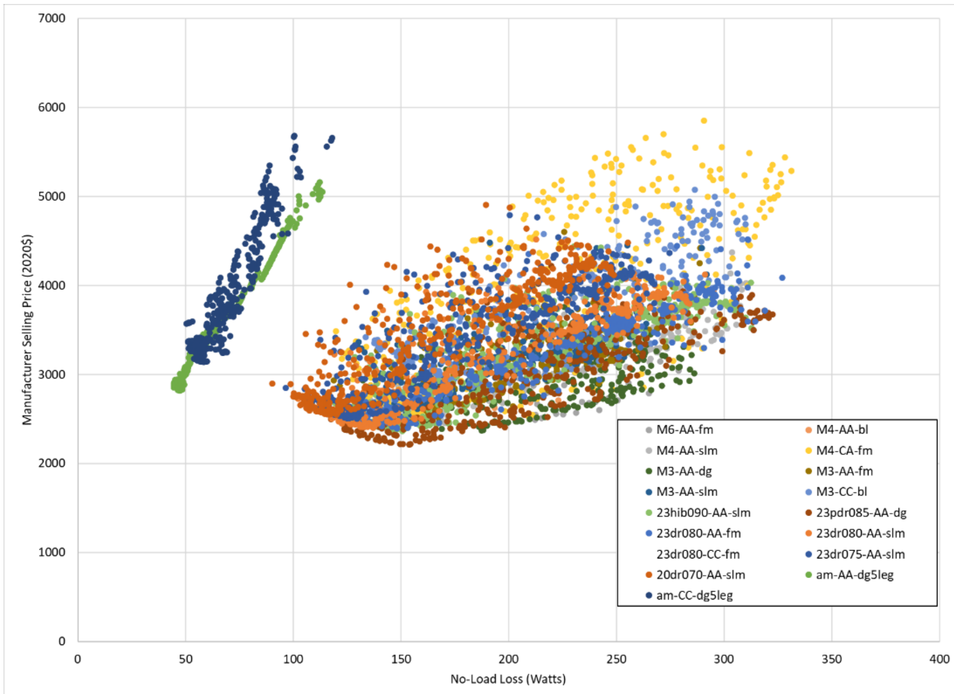


Figure 5A.2.19 Plot of Manufacturer Selling Price and No-Load Loss for RU7

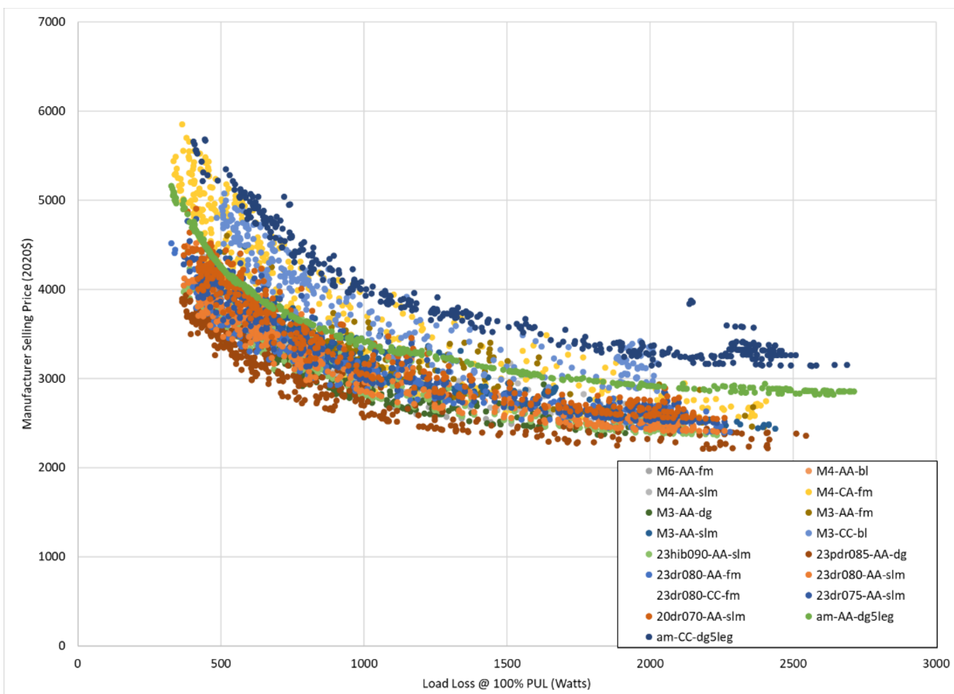


Figure 5A.2.20 Plot of Manufacturer Selling Price and Load Loss for RU7

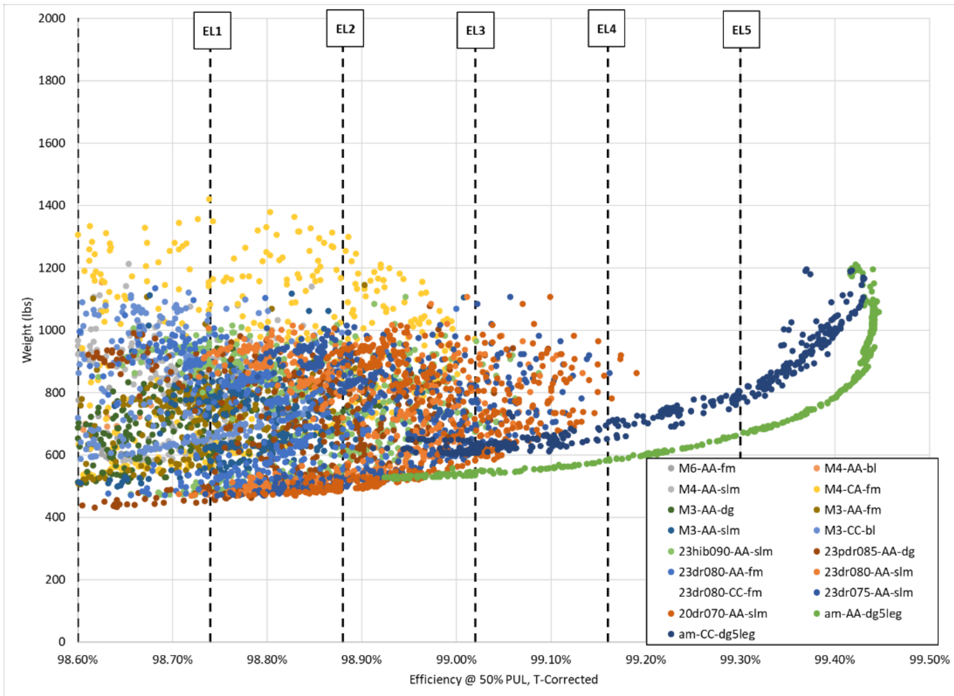


Figure 5A.2.21 Plot of Weight and Efficiency for RU7

5A.2.8 Representative Unit 8

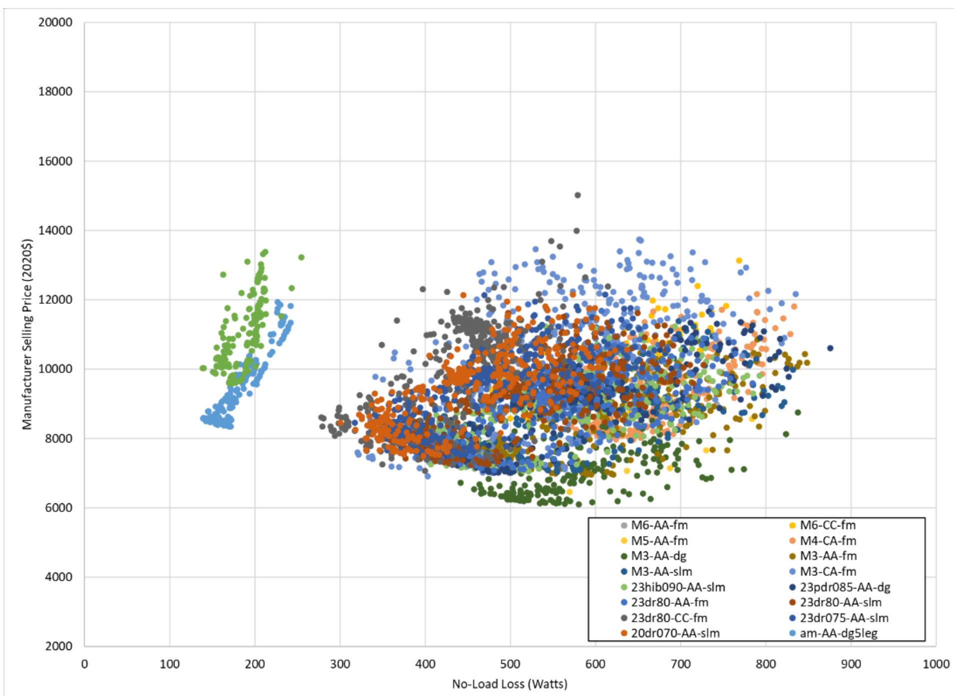


Figure 5A.2.22 Plot of Manufacturer Selling Price and No-Load Loss for RU8

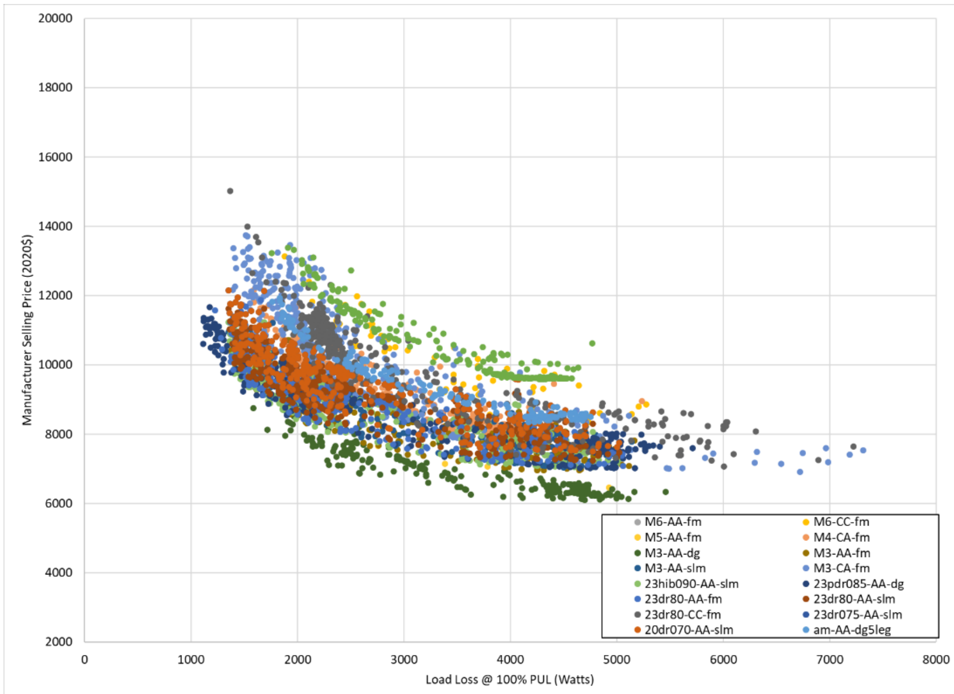


Figure 5A.2.23 Plot of Manufacturer Selling Price and Load Loss for RU8

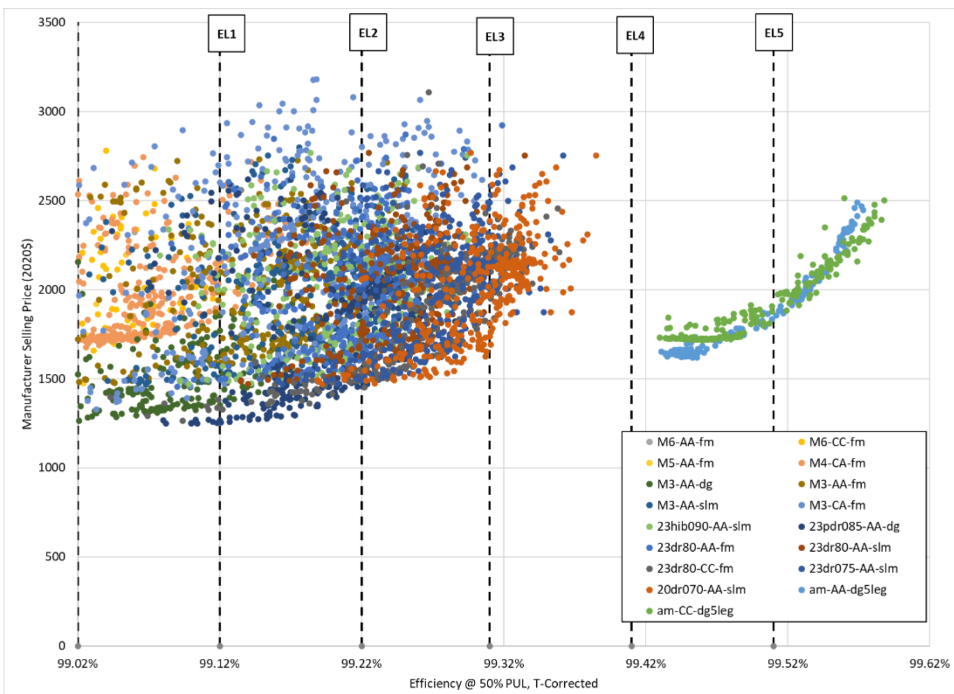


Figure 5A.2.24 Plot of Weight and Efficiency for RU8

5A.2.9 Representative Unit 9

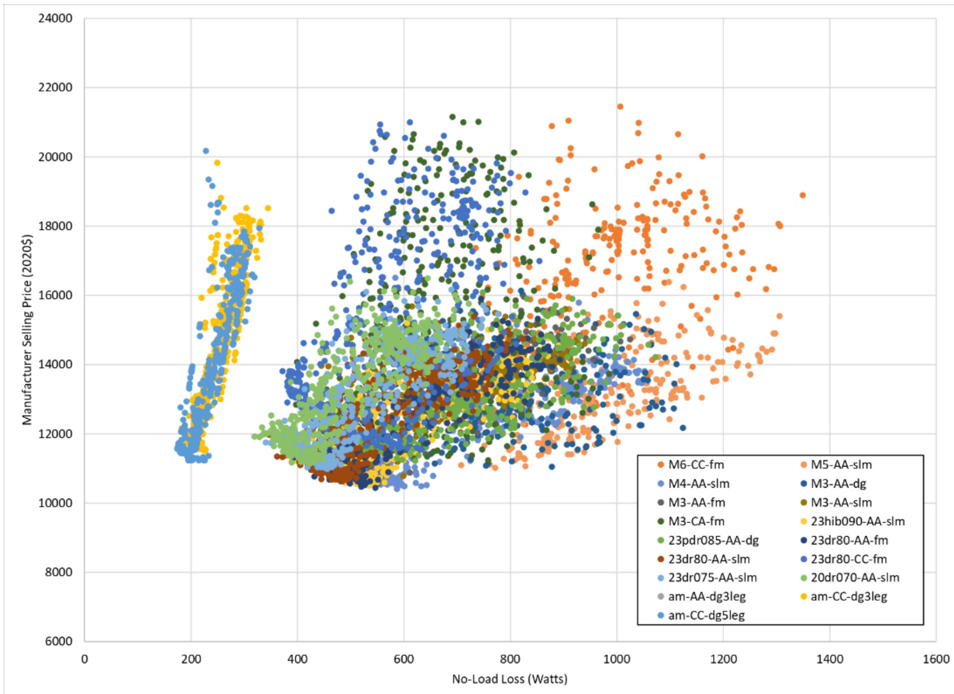


Figure 5A.2.25 Plot of Manufacturer Selling Price and No-Load Loss for RU9

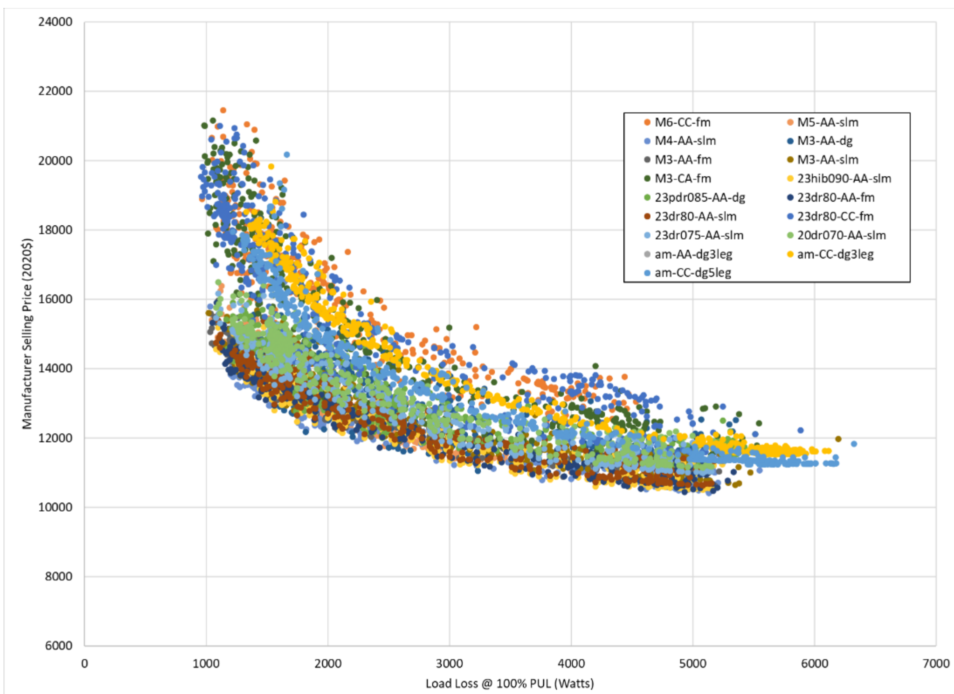


Figure 5A.2.26 Plot of Manufacturer Selling Price and Load Loss for RU9

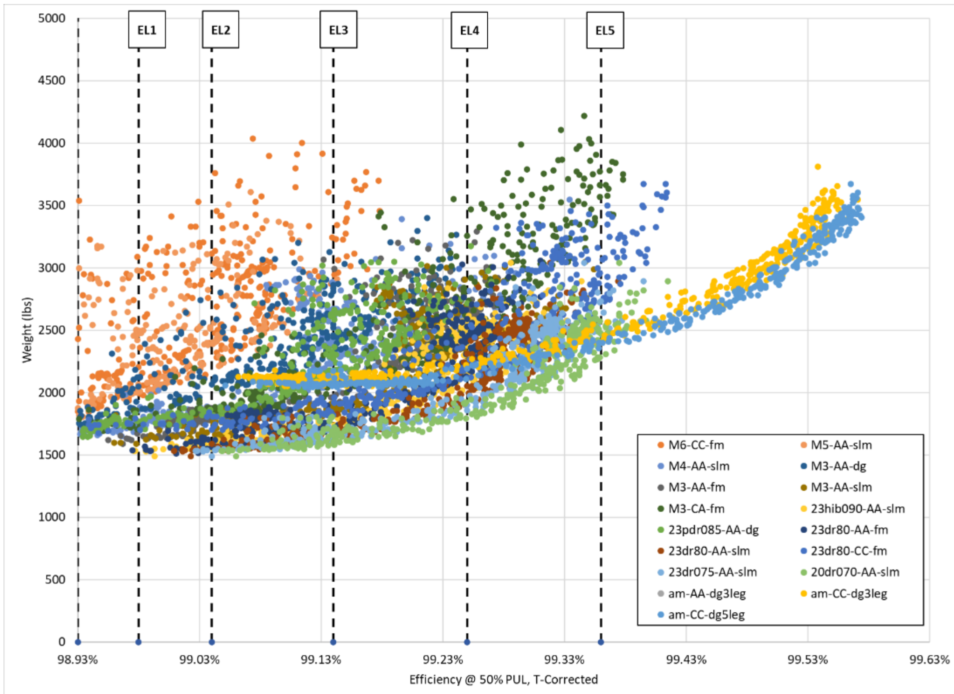


Figure 5A.2.27 Plot of Weight and Efficiency for RU9

5A.2.10 Representative Unit 10

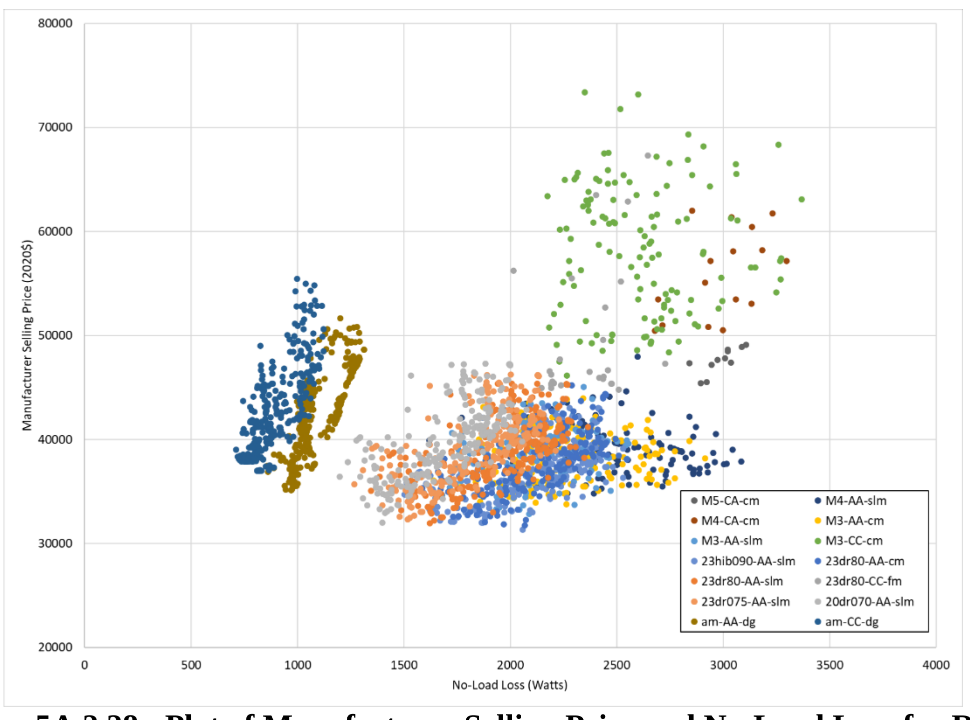


Figure 5A.2.28 Plot of Manufacturer Selling Price and No-Load Loss for RU10

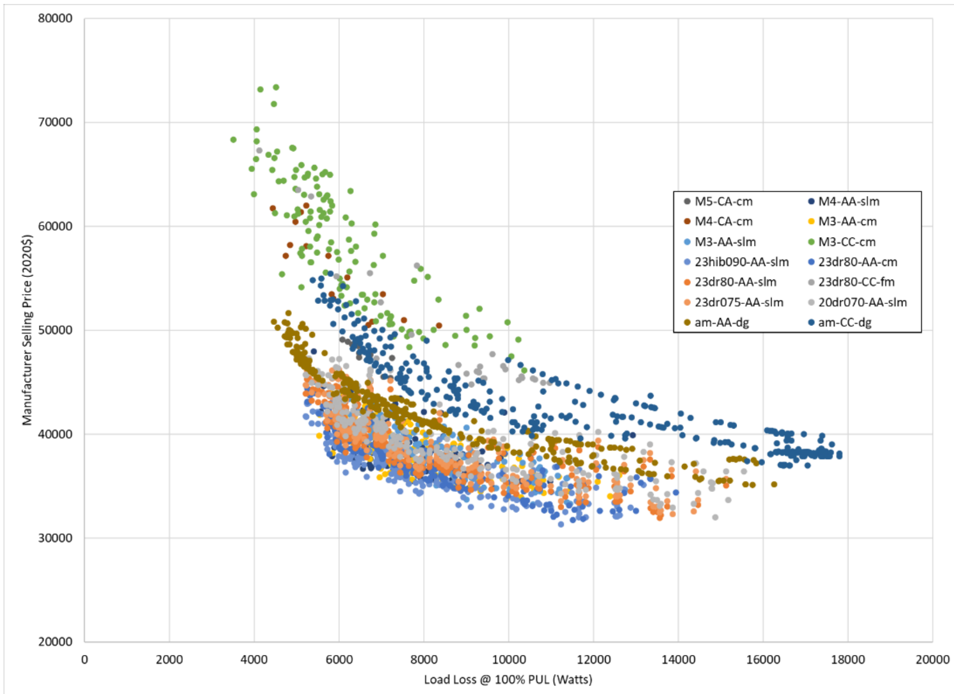


Figure 5A.2.29 Plot of Manufacturer Selling Price and Load Loss for RU10

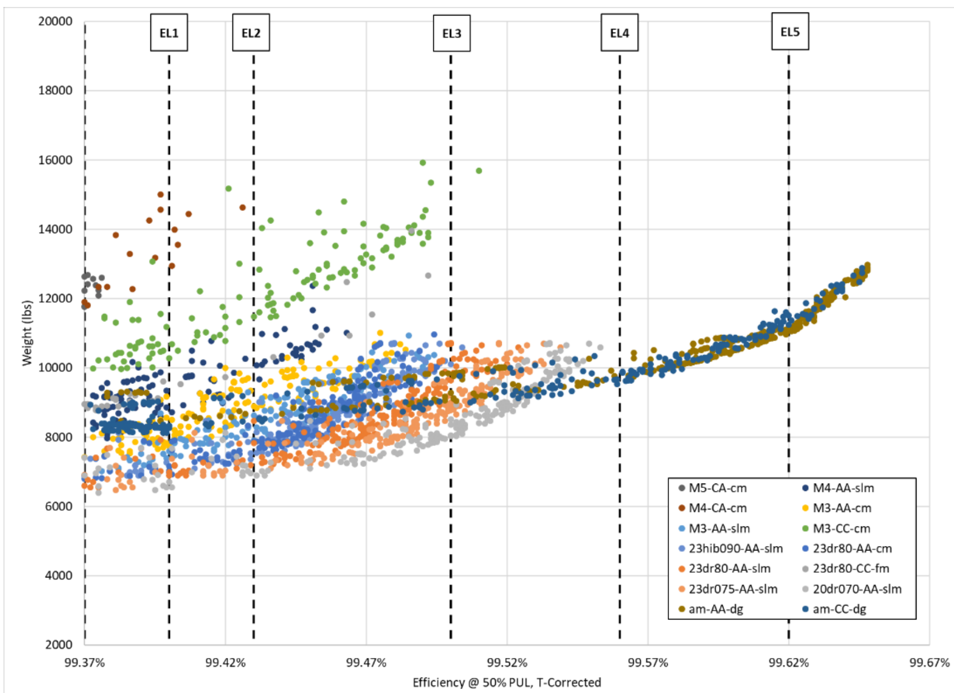


Figure 5A.2.30 Plot of Weight and Efficiency for RU10

5A.2.11 Representative Unit 11

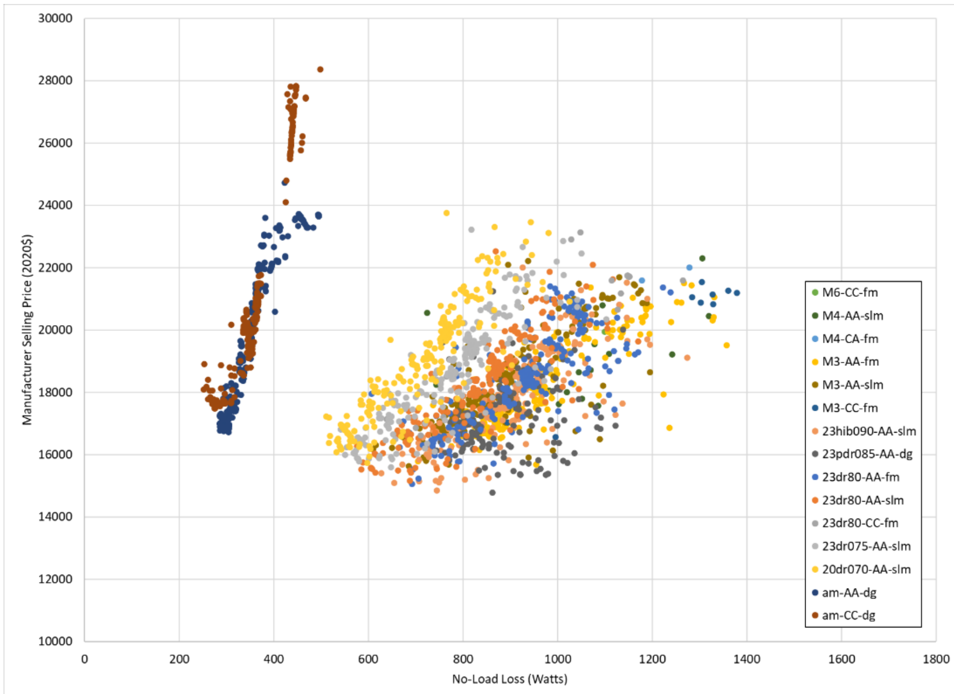


Figure 5A.2.31 Plot of Manufacturer Selling Price and No-Load Loss for RU11

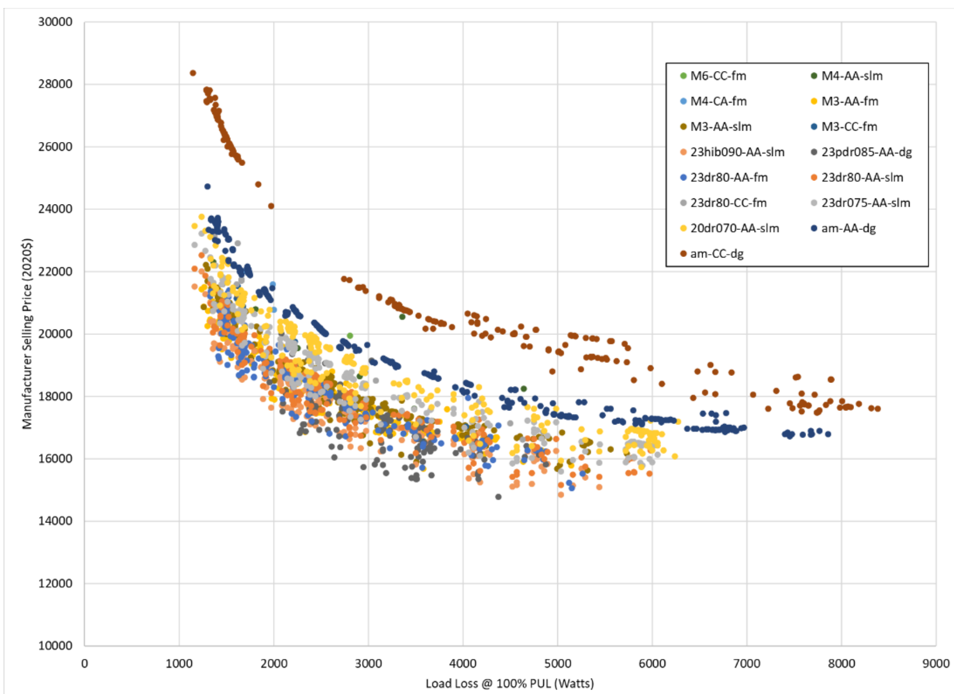


Figure 5A.2.32 Plot of Manufacturer Selling Price and Load Loss for RU11

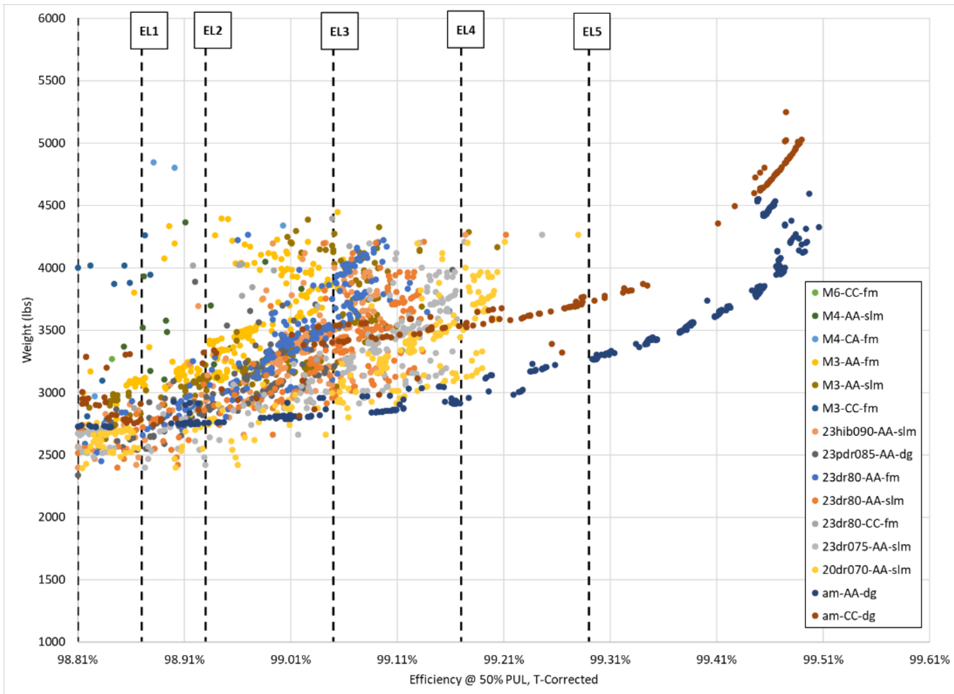


Figure 5A.2.33 Plot of Weight and Efficiency for RU11

5A.2.12 Representative Unit 12

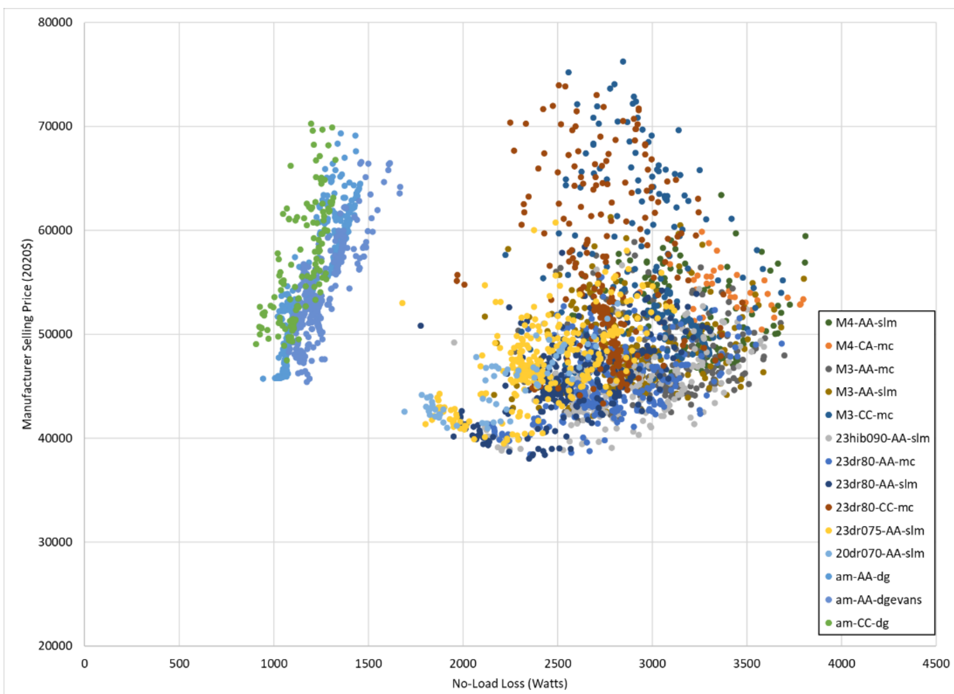


Figure 5A.2.34 Plot of Manufacturer Selling Price and No-Load Loss for RU12

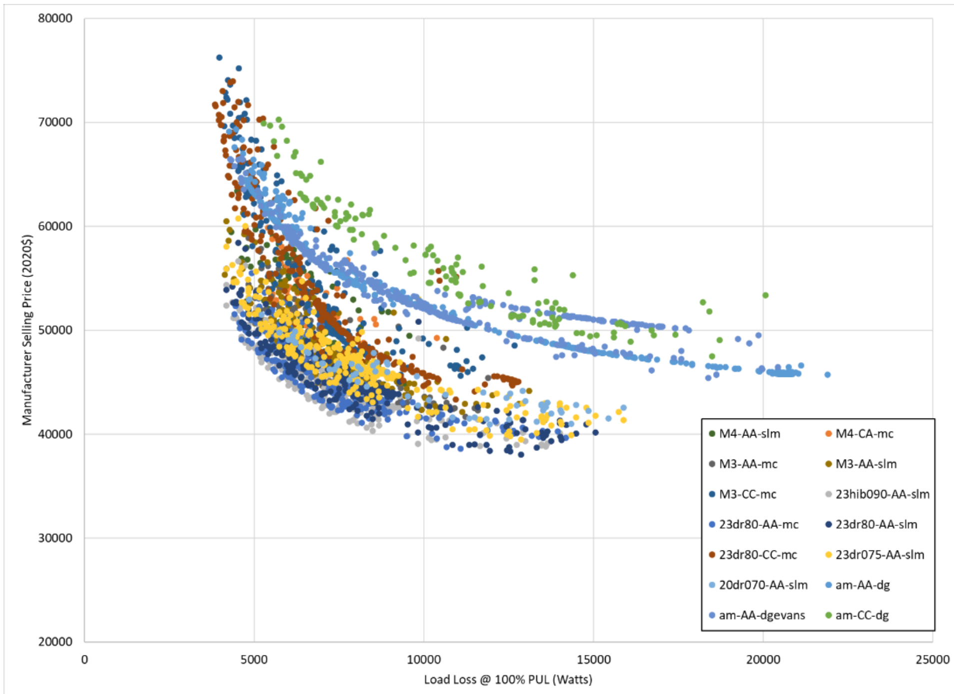


Figure 5A.2.35 Plot of Manufacturer Selling Price and Load Loss for RU12

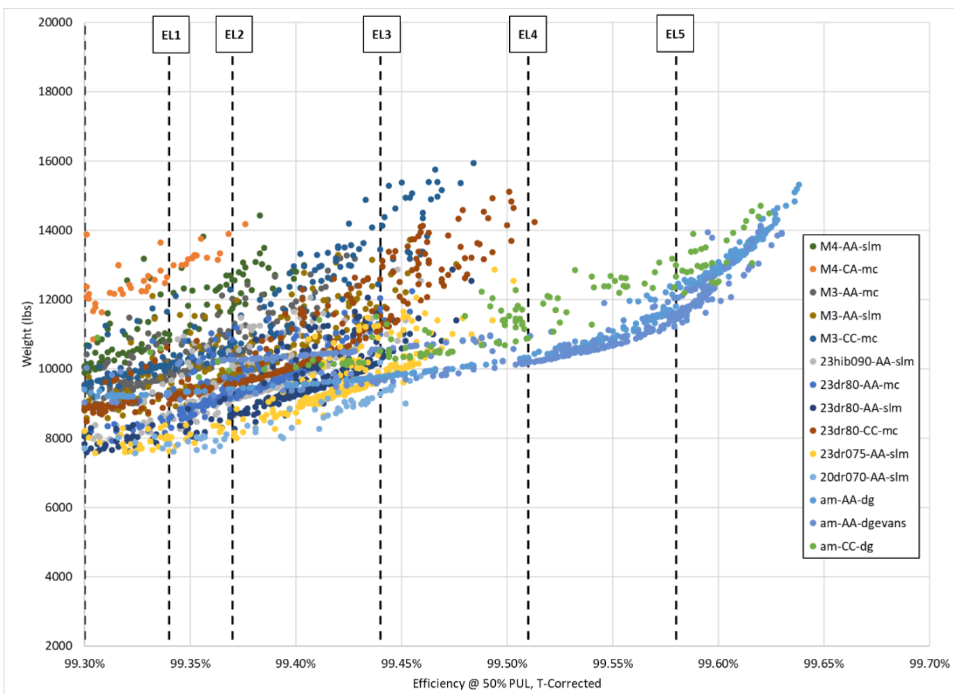


Figure 5A.2.36 Plot of Weight and Efficiency for RU12

5A.2.13 Representative Unit 13

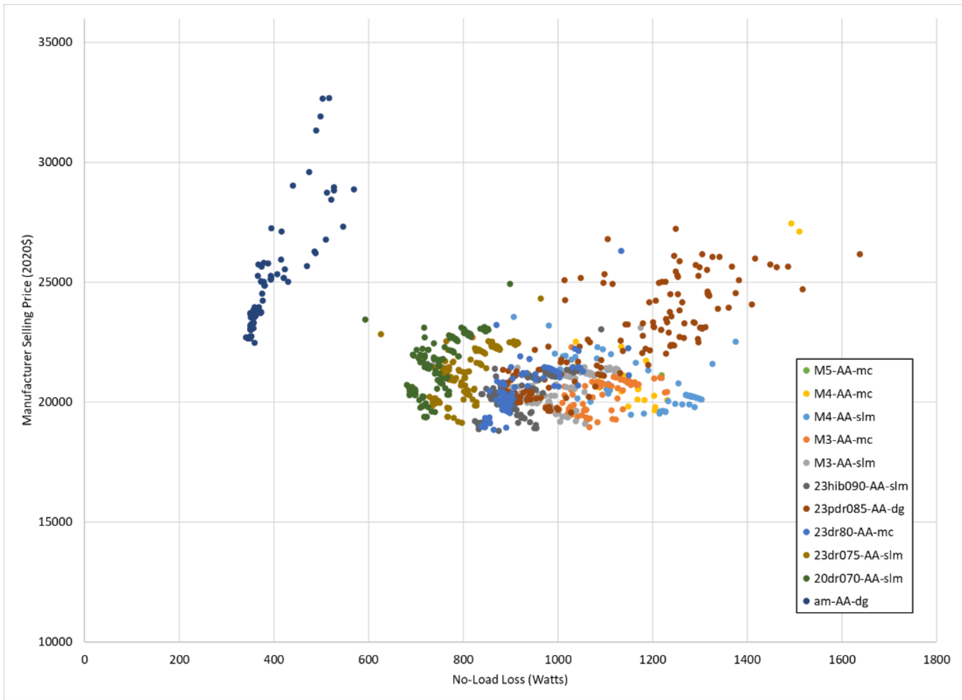


Figure 5A.2.37 Plot of Manufacturer Selling Price and No-Load Loss for RU13

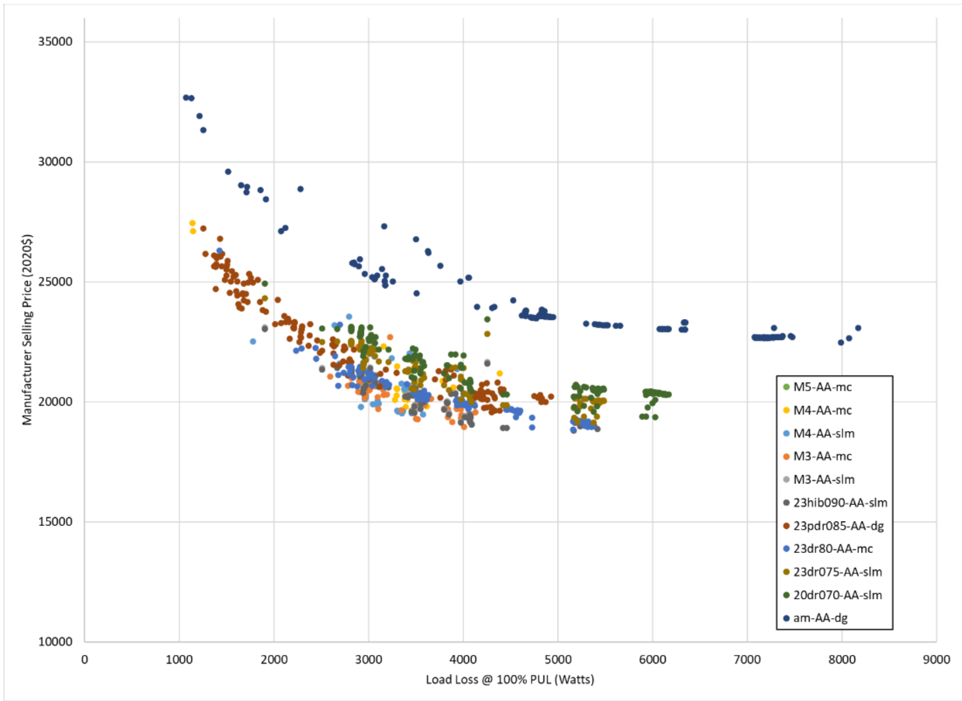


Figure 5A.2.38 Plot of Manufacturer Selling Price and Load Loss for RU13

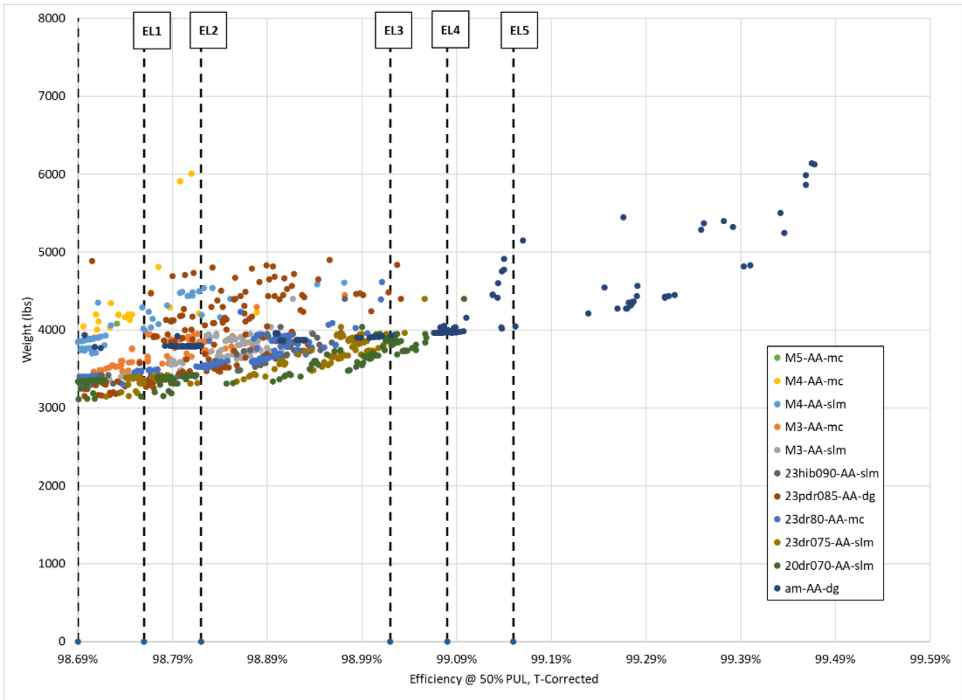


Figure 5A.2.39 Plot of Weight and Efficiency for RU13

5A.2.14 Representative Unit 14

Figure 5A.2.40 Plot of Manufacturer Selling Price and No-Load Loss for RU14

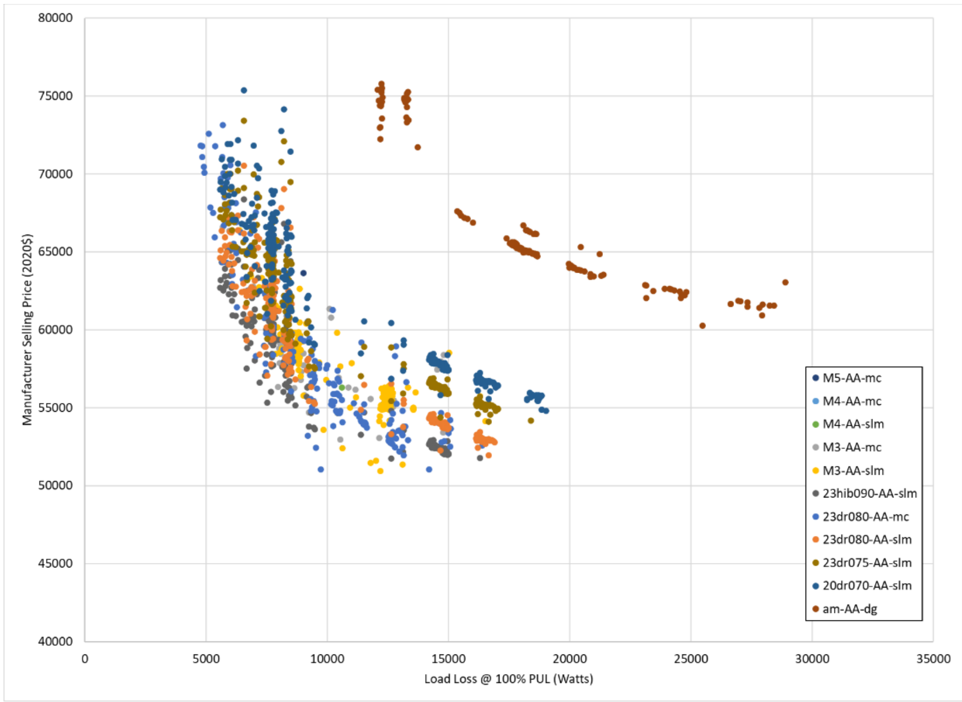


Figure 5A.2.41 Plot of Manufacturer Selling Price and Load Loss for RU14

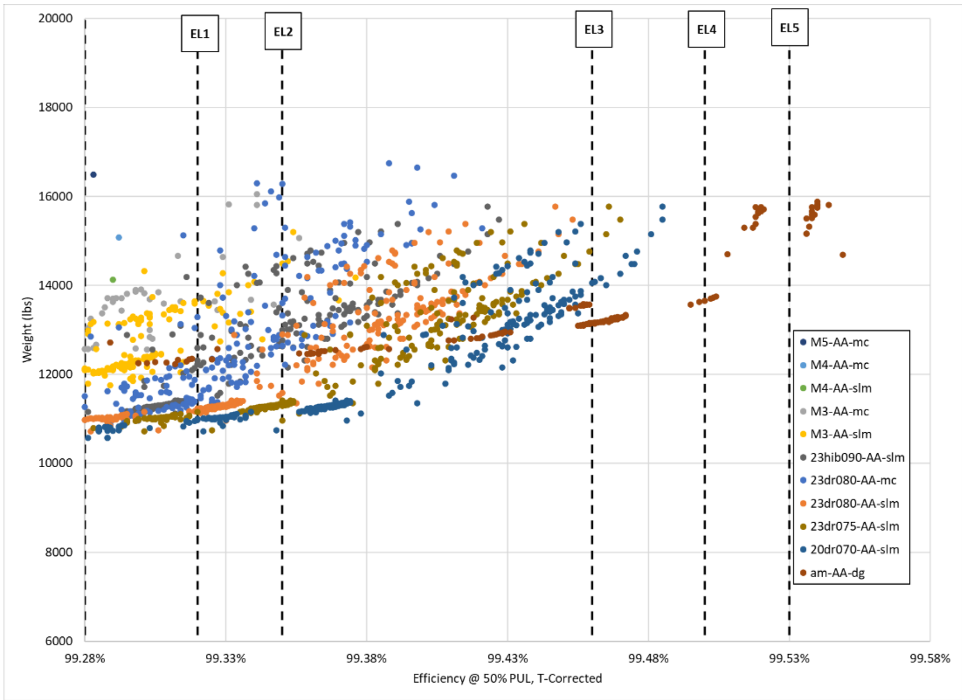


Figure 5A.2.42 Plot of Weight and Efficiency for RU14

APPENDIX 5B. MATERIAL PRICE SENSITIVITY ENGINEERING RESULTS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDIX 5B. MATERIAL PRICE SENSITIVITY ENGINEERING RESULTS

5B.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. As described in chapter 3 and chapter 5 of the technical support document (TSD), tariffs, and the way manufacturers have responded to tariffs have a notable impact on distribution transformer prices. Therefore, in addition to its analysis using the current 2020 material price, which assumes a partial mitigation of the tariffs, the Department of Energy (DOE) conducted two sensitivity analysis. The first using material prices in which tariffs are expanded to finished cores (Expanded Core Tariff Case) and the second using material prices in which no tariffs are applied (No Tariff Case). The results of the reference case is presented in chapter 5. The results of the material price sensitivity analyses are presented in this appendix. All material prices are expressed in terms of 2020$.

The life-cycle cost (LCC) results for the material price sensitivity analyses can be found in TSD Appendix 8E, which presents DOE's sensitivity analyses conducted on various LCC inputs, including material prices. These material prices used in the base case and the sensitivity analysis are reproduced from chapter 5 for reference.

Table 5B.1.1 Conductor Prices

Item and description	Base Case ($/lb)	No Tariffs Case ($/lb)	Expanded Core Tariff Case ($/lb)
Copper wire, formvar, round #10-20	$3.89	$3.89	$3.89
Copper wire, enameled, round #7-10	$4.03	$4.03	$4.03
Copper wire, enameled, rectangular sizes	$4.22	$4.22	$4.22
Copper wire, rectangular 0.1 x 0.2, Nomex wrapped	$3.89	$3.89	$3.89
Copper strip, thickness range 0.02-0.045	$3.75	$3.75	$3.75
Copper strip, thickness range 0.030-0.060	$3.59	$3.59	$3.59
Aluminum wire, formvar, round #9-17	$3.75	$3.49	$3.49
Aluminum wire, formvar, round #7-10	$3.20	$2.97	$2.97
Aluminum wire, rectangular #<7	$3.49	$3.25	$3.25
Aluminum wire, rectangular 0.1 x 0.2, Nomex wrapped	$2.27	$2.12	$2.12
Aluminum strip, thickness range 0.02-0.045	$1.67	$1.55	$1.55
Aluminum strip, thickness range 0.045-0.080	$1.70	$1.58	$1.58

Table 5B.1.2 Electrical Steel Material Prices

Item and description	Base Case ($/lb)	No Tariffs Case ($/lb)	Expanded Core Tariff Case ($/lb)
Grain-Oriented Electrical Steel			
M6	$1.13	$0.95	$1.19
M5	$1.10	$0.92	$1.15
M4	$1.11	$0.93	$1.16
M3	$1.30	$1.10	$1.37
M2	$1.43	$1.20	$1.50
High-Permeability Grain-Oriented Electrical Steel			
23hib090	$1.28	$1.08	$1.35
23pdr085 (permanently domain-refined)	$1.52	$1.28	$1.60
23dr080 (domain-refined)	$1.42	$1.20	$1.50
23pdr075 (permanently domain-refined)	$1.69	$1.43	$1.78
23dr075 (domain-refined)	$1.69	$1.35	$1.69
20dr070 (domain-refined)	$1.71	$1.44	$1.80
Amorphous Electrical Steel (Finished Cores)			
am	$1.84	$1.55	$1.94

Table 5B.1.3 Other Material Prices

Item and description	Base Case ($/lb)	No Tariffs Case ($/lb)	Expanded Core Tariff Case ($/lb)
Nomex Insulation	$28.24	$28.24	$28.24
Kraft insulating paper with diamond adhesive	$2.08	$2.08	$2.08
Mineral oil	$2.76	$2.76	$2.76
Impregnation	$25.99	$25.99	$25.99
Winding Combs	$14.22	$14.22	$14.22
Tank/Enclosure Steel	$0.35	$0.30	$0.37

5B.2 REPRESENTATIVE UNITS

5B.2.1 Representative Unit 1

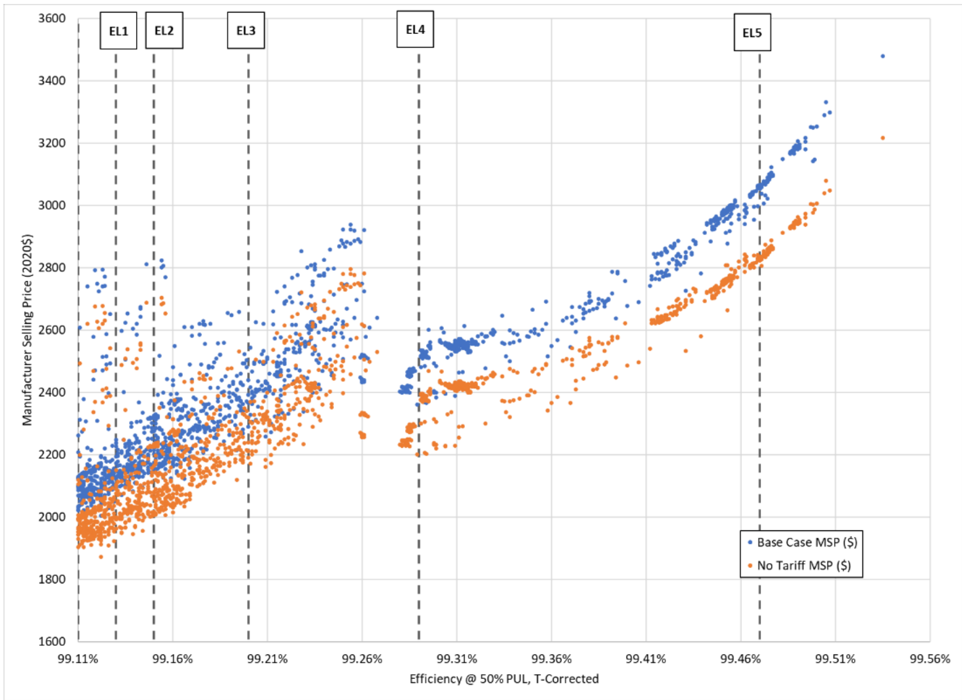


Figure 5B.2.1 No Tariff Material Price Comparison Plot, RU1

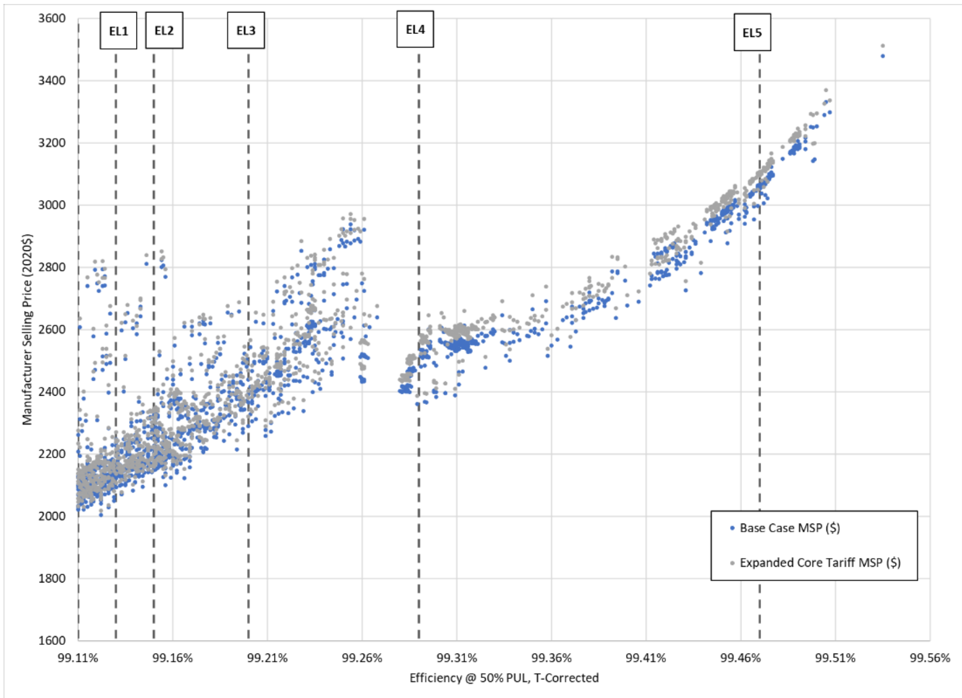


Figure 5B.2.2 Expanded Core Tariff Material Price Comparison Plot, RU1

5B.2.2 Representative Unit 2

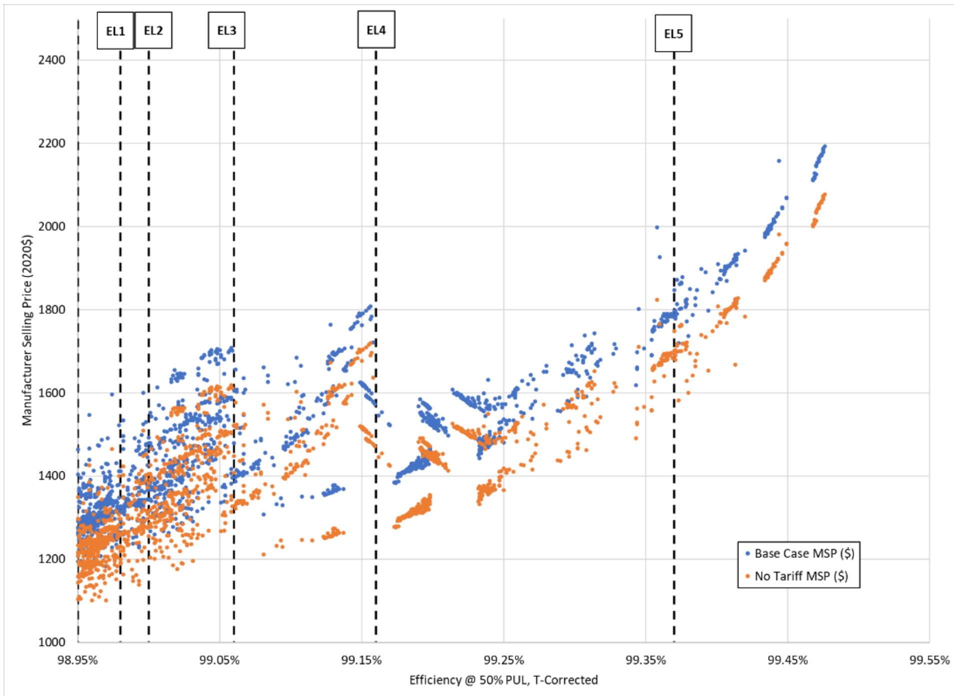


Figure 5B.2.3 No Tariff Material Price Comparison Plot, RU2

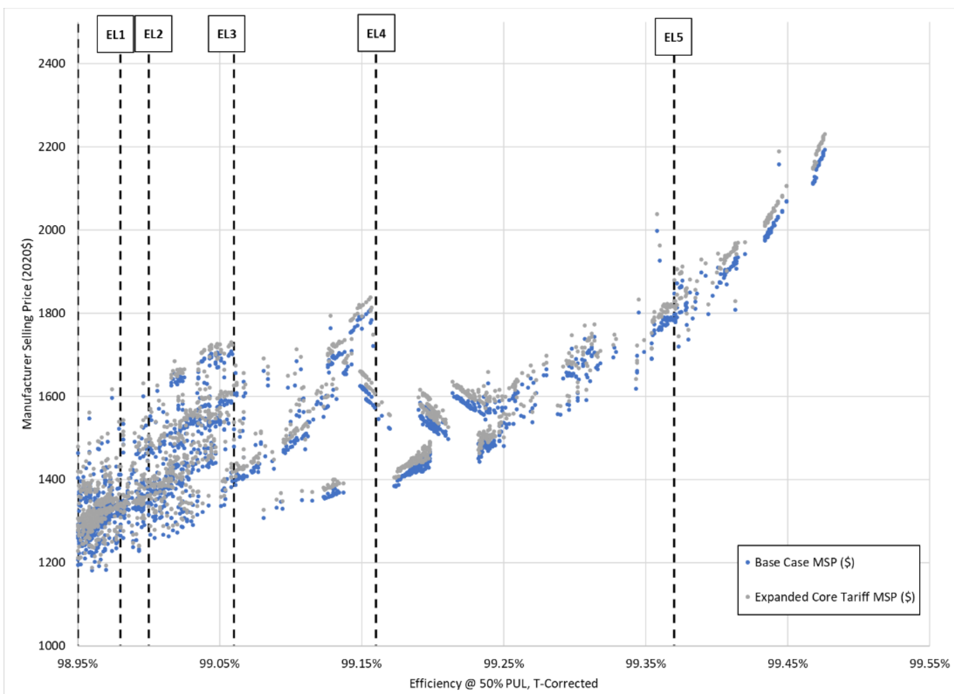


Figure 5B.2.4 Expanded Core Tariff Material Price Comparison Plot, RU2

5B.2.3 Representative Unit 3

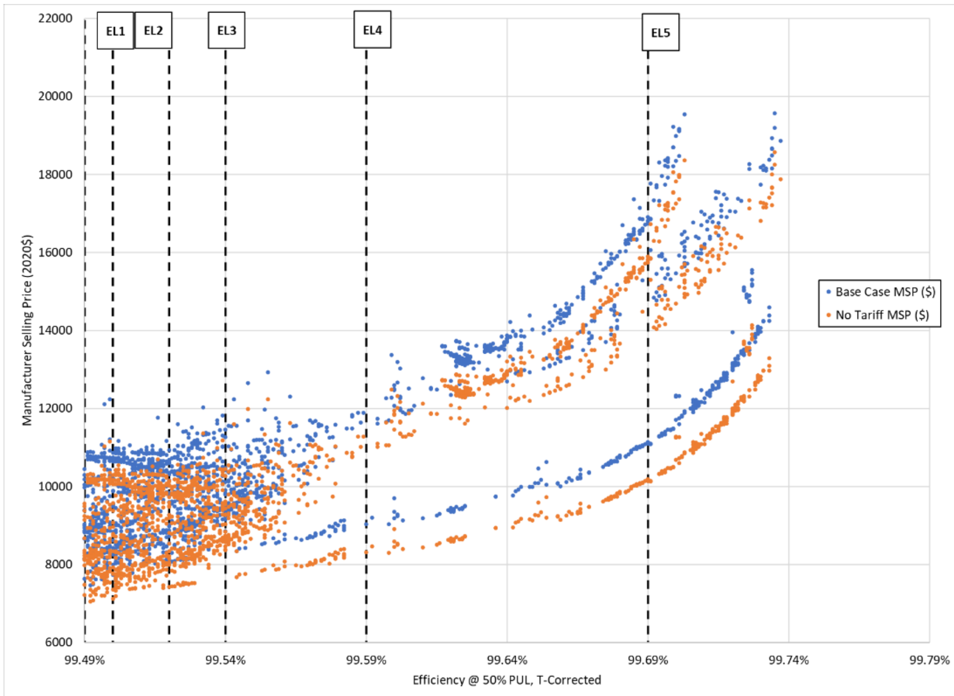


Figure 5B.2.5 No Tariff Material Price Comparison Plot, RU3

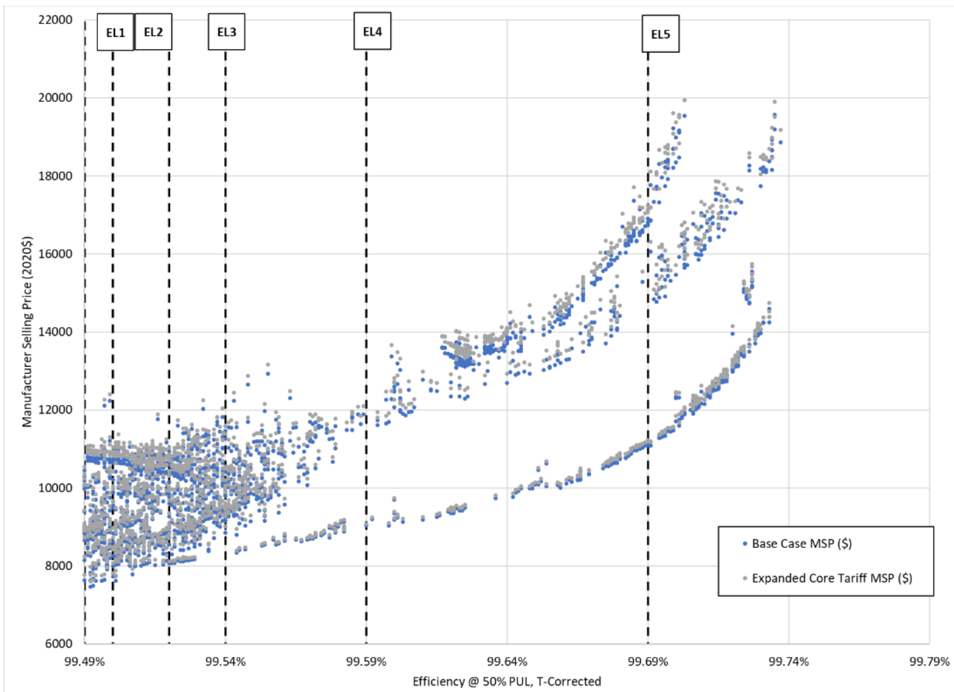


Figure 5B.2.6 Expanded Core Tariff Material Price Comparison Plot, RU3

5B.2.4 Representative Unit 4

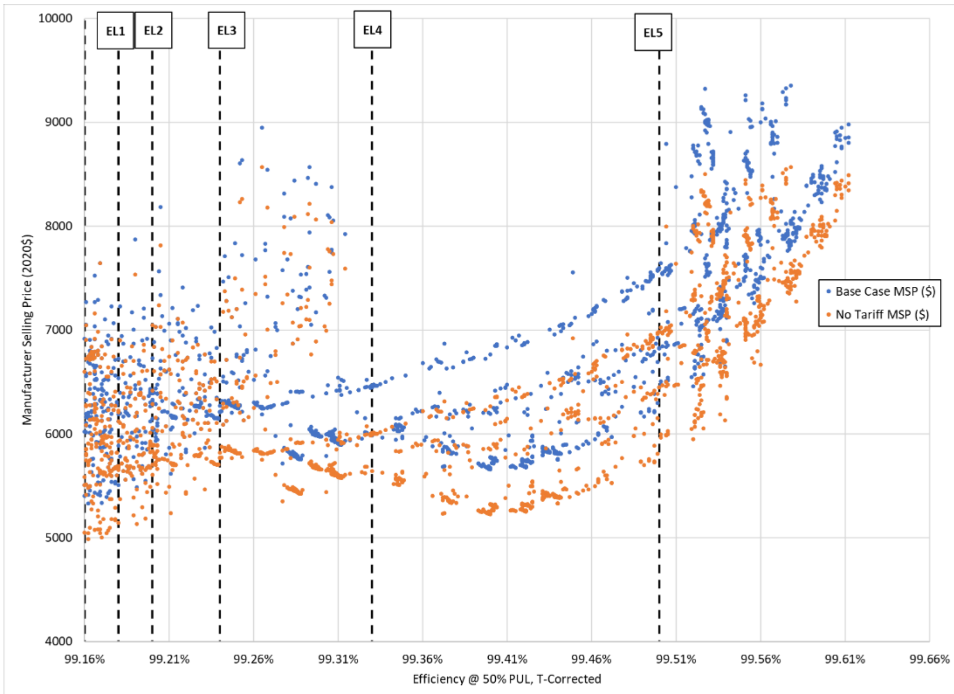


Figure 5B.2.7 No Tariff Material Price Comparison Plot, RU4

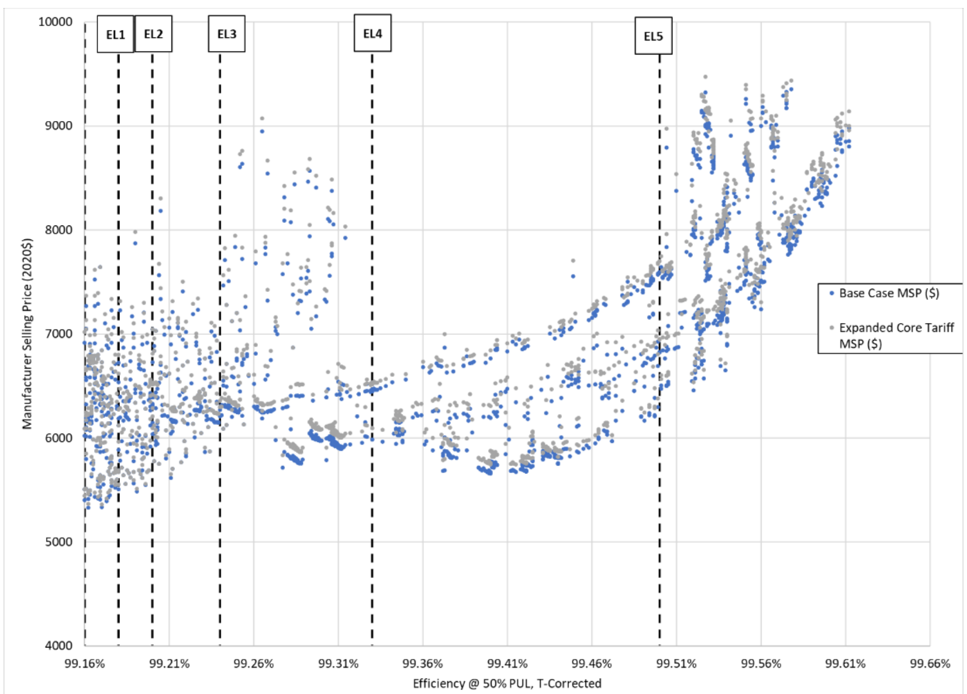


Figure 5B.2.8 Expanded Core Tariff Material Price Comparison Plot, RU4

5B.2.5 Representative Unit 5

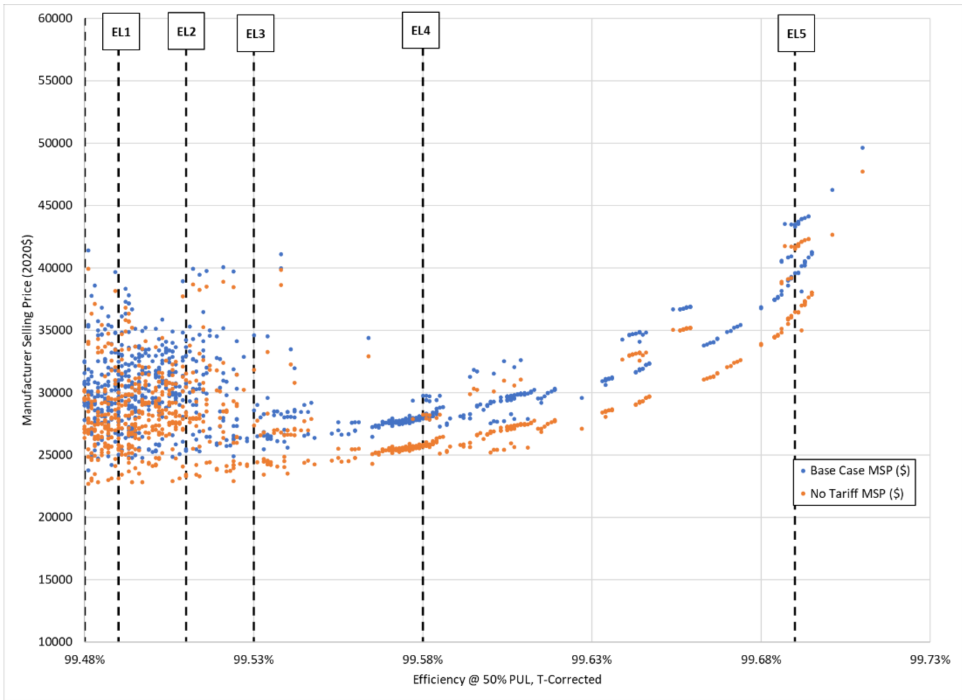


Figure 5B.2.9 No Tariff Material Price Comparison Plot, RU5

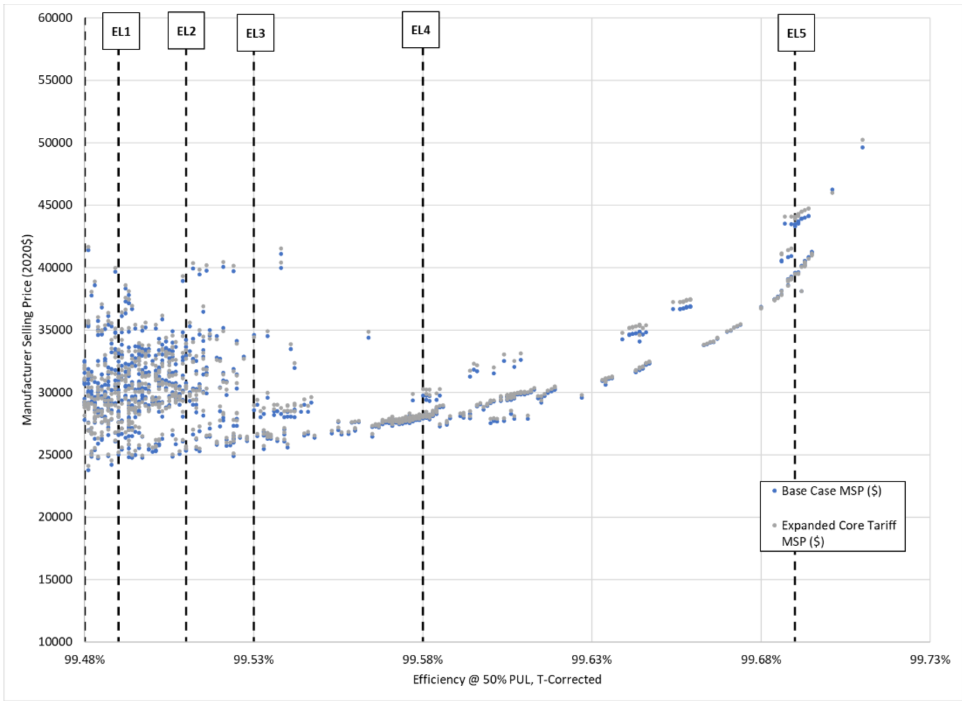


Figure 5B.2.10 Expanded Core Tariff Material Price Comparison Plot, RU5

5B.2.6 Representative Unit 6

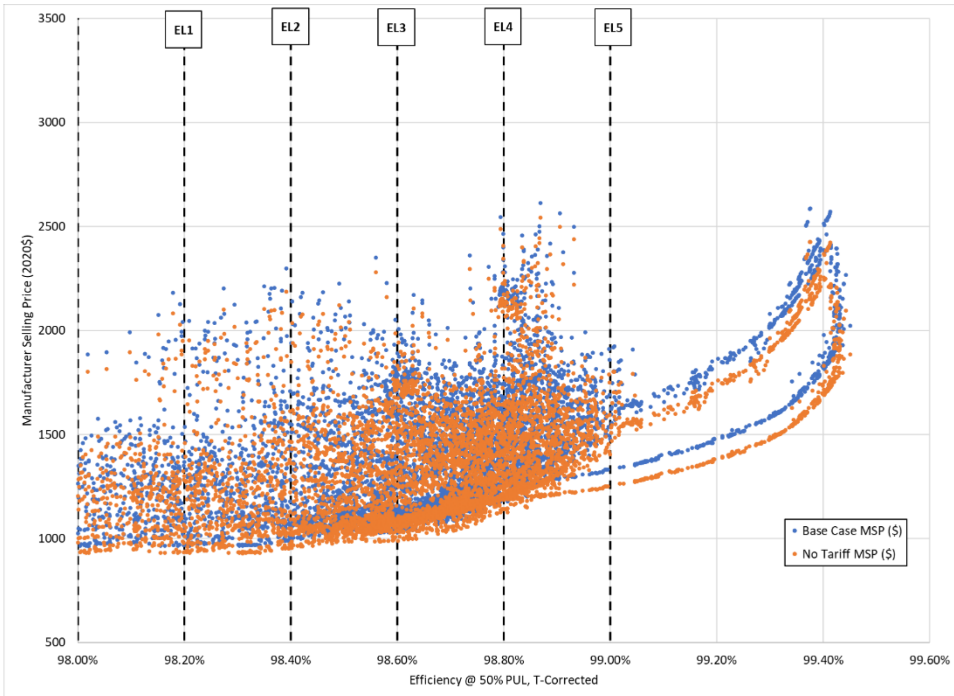


Figure 5B.2.11 No Tariff Material Price Comparison Plot, RU6

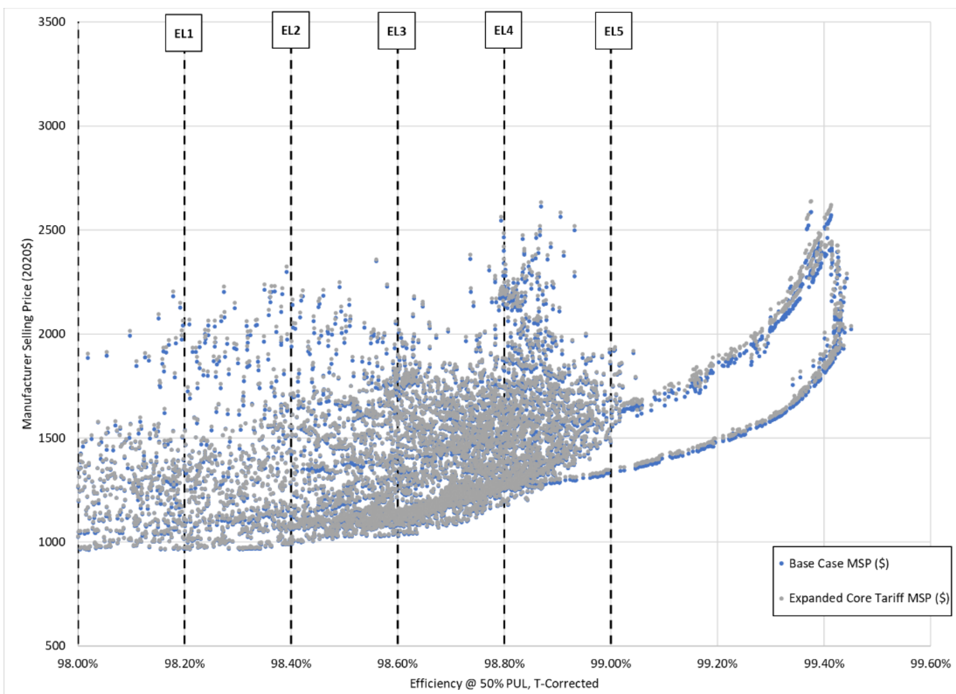


Figure 5B.2.12 Expanded Core Tariff Material Price Comparison Plot, RU6

5B.2.7 Representative Unit 7

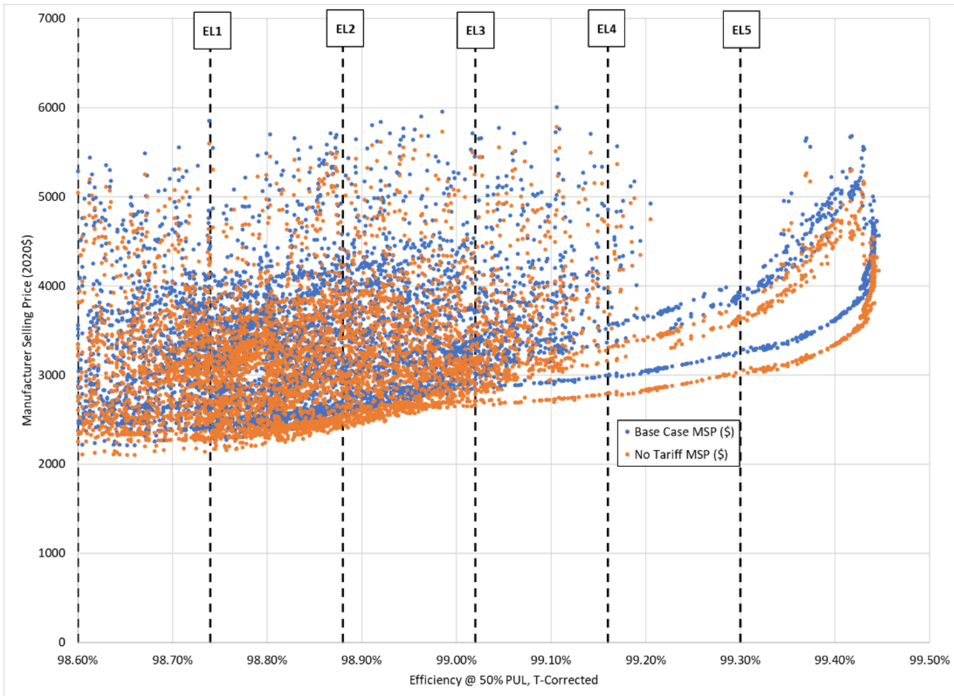


Figure 5B.2.13 No Tariff Material Price Comparison Plot, RU7

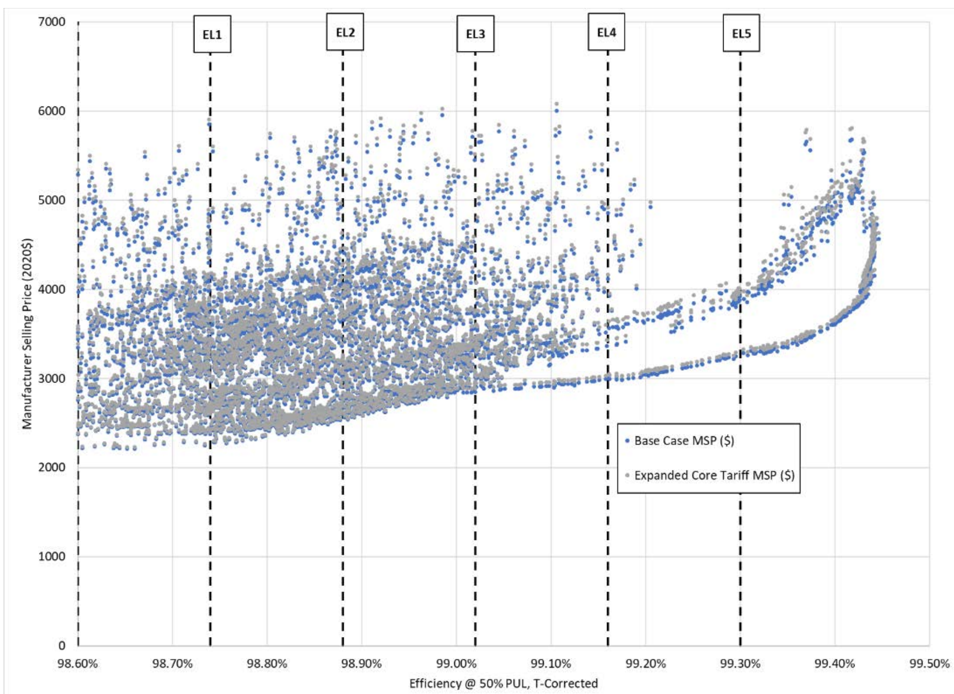


Figure 5B.2.14 Expanded Core Tariff Material Price Comparison Plot, RU7

5B.2.8 Representative Unit 8

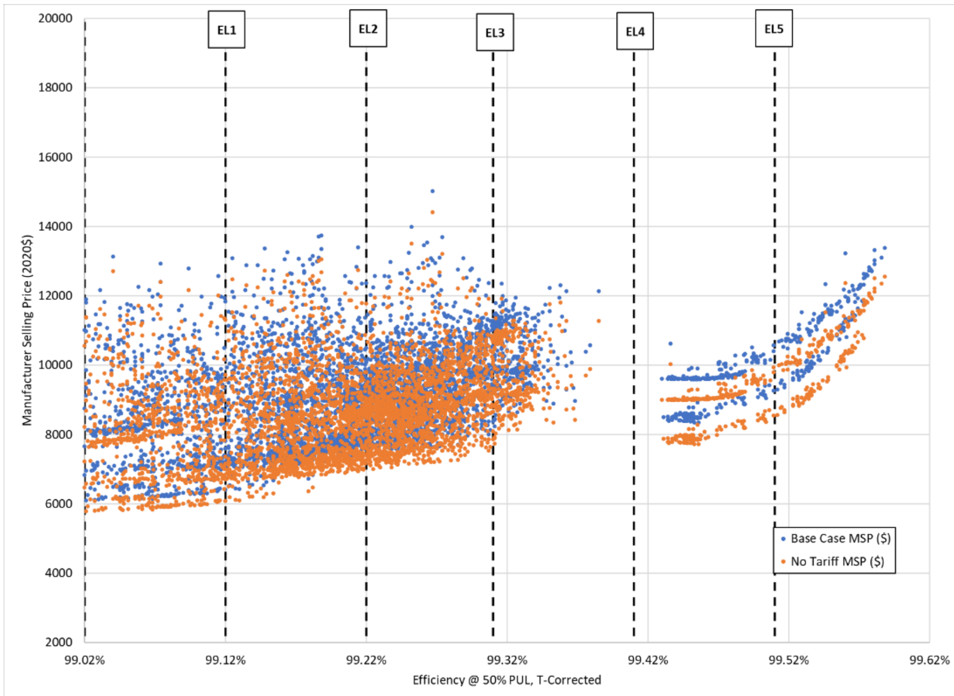


Figure 5B.2.15 No Tariff Material Price Comparison Plot, RU8

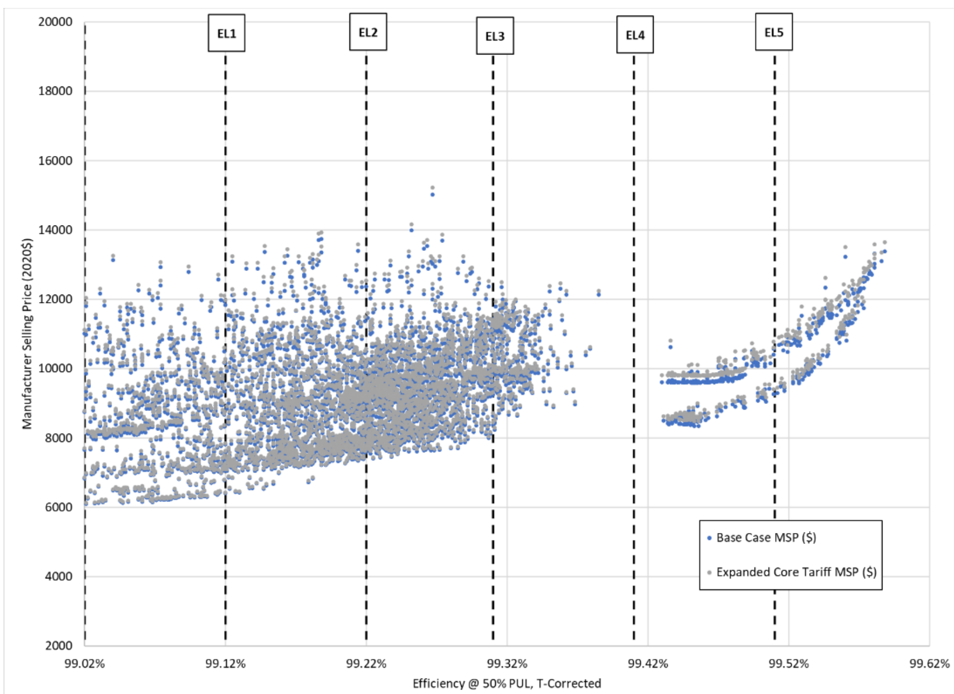


Figure 5B.2.16 Expanded Core Tariff Material Price Comparison Plot, RU8

5B.2.9 Representative Unit 9

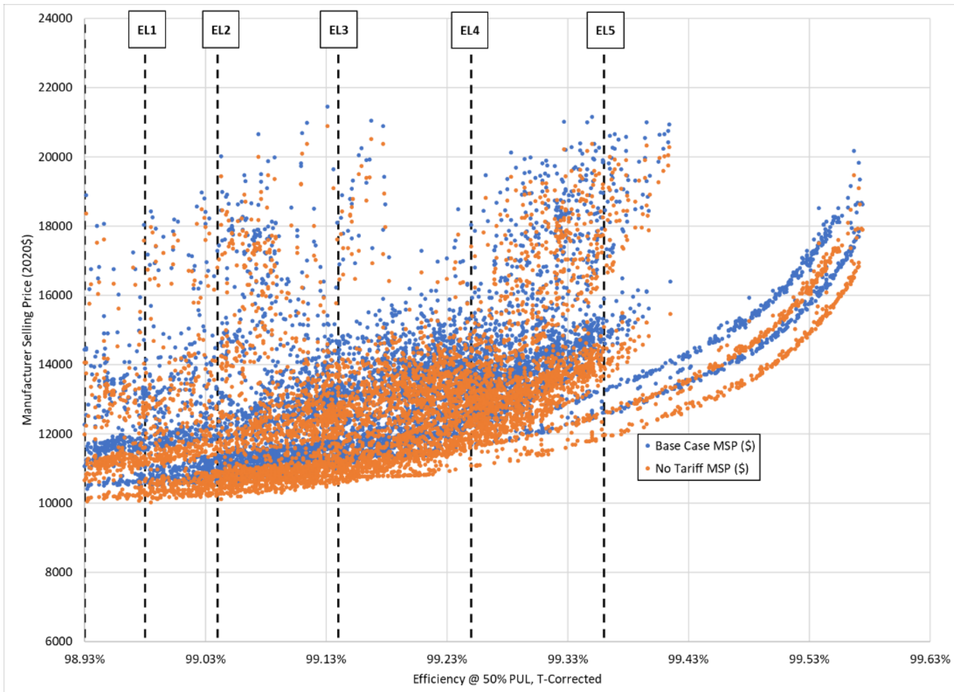


Figure 5B.2.17 No Tariff Material Price Comparison Plot, RU9

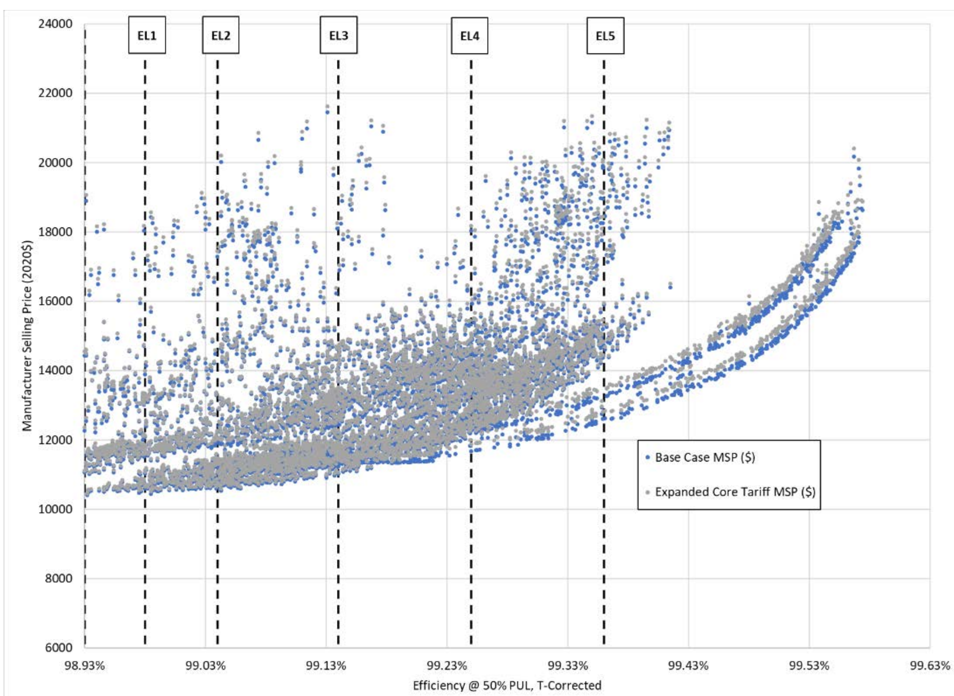


Figure 5B.2.18 Expanded Core Tariff Material Price Comparison Plot, RU9

5B.2.10 Representative Unit 10

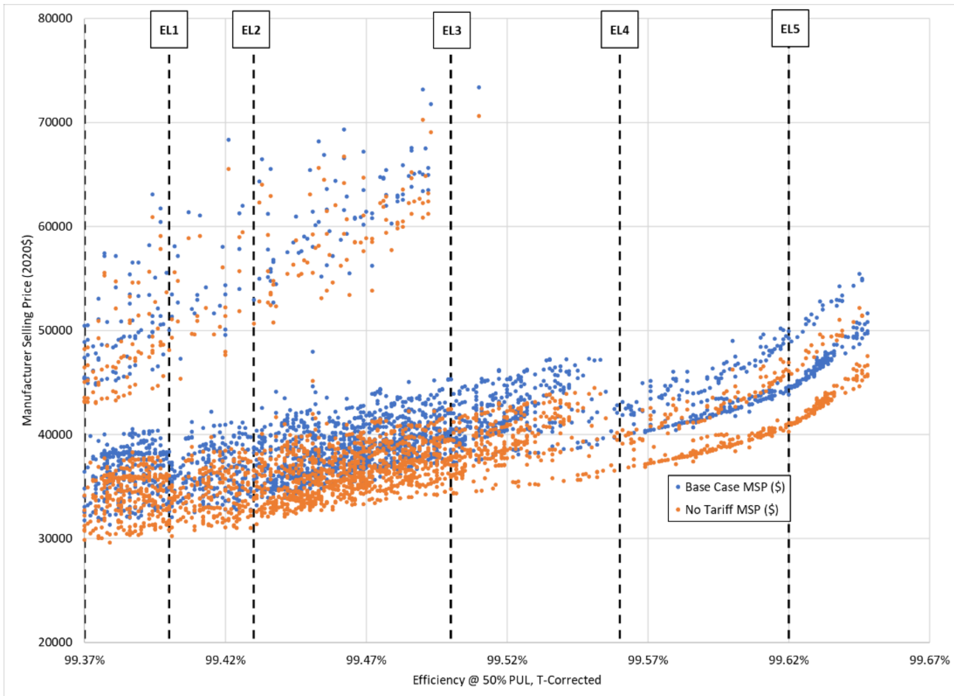


Figure 5B.2.19 No Tariff Material Price Comparison Plot, RU10

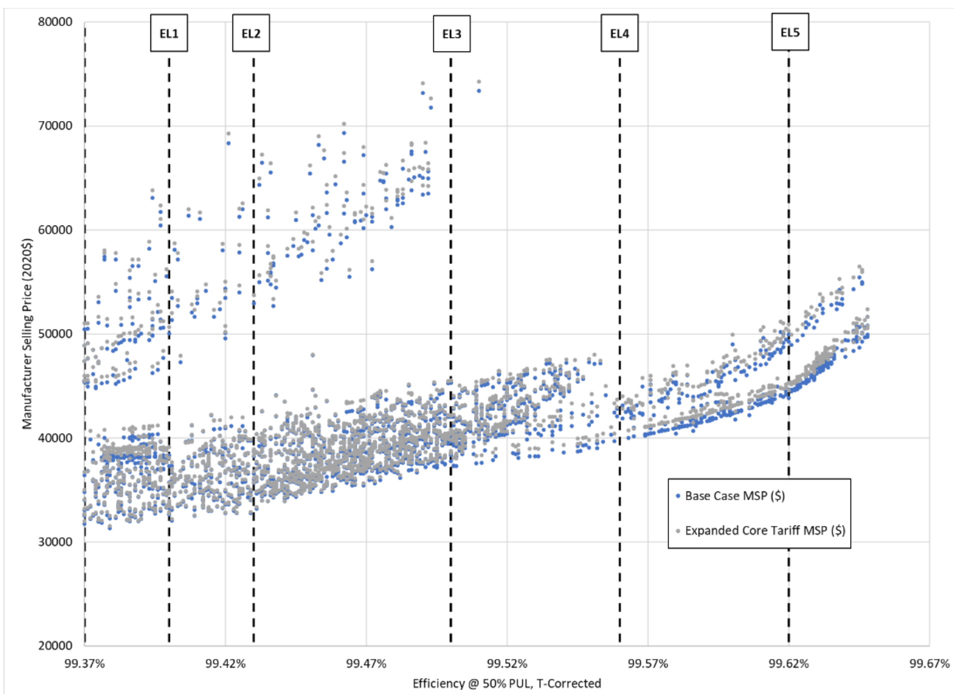


Figure 5B.2.20 Expanded Core Tariff Material Price Comparison Plot, RU10

5B.2.11 Representative Unit 11

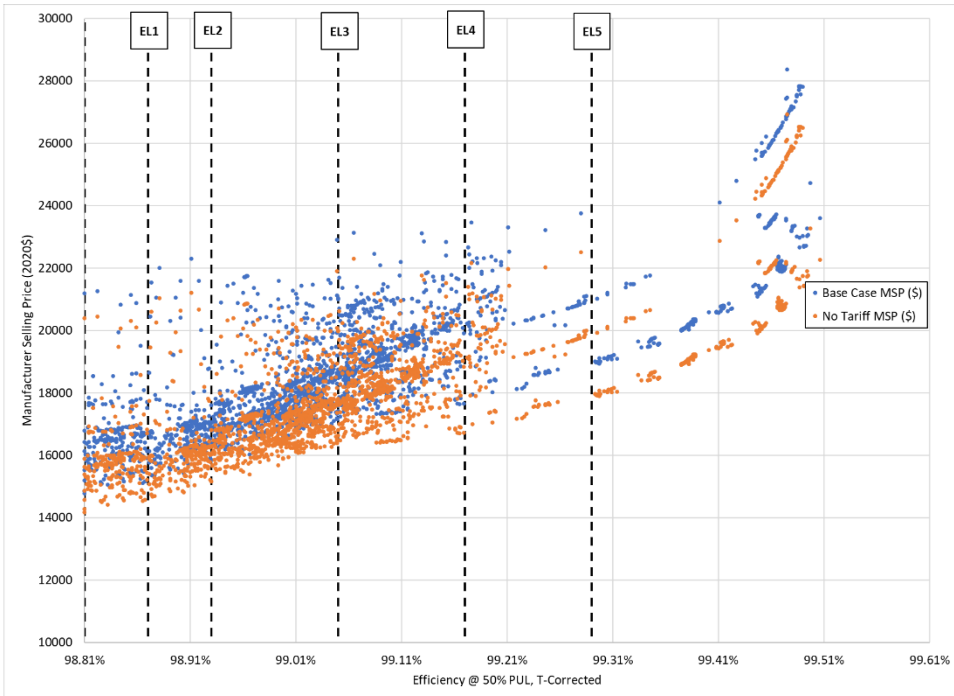


Figure 5B.2.21 No Tariff Material Price Comparison Plot, RU11

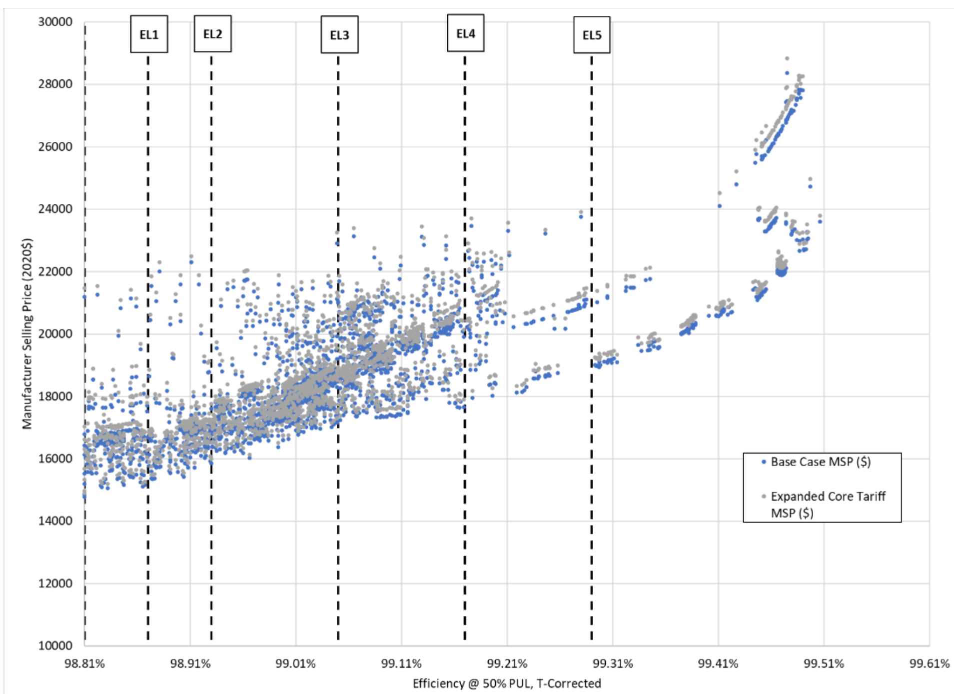


Figure 5B.2.22 Expanded Core Tariff Material Price Comparison Plot, RU11

5B.2.12 Representative Unit 12

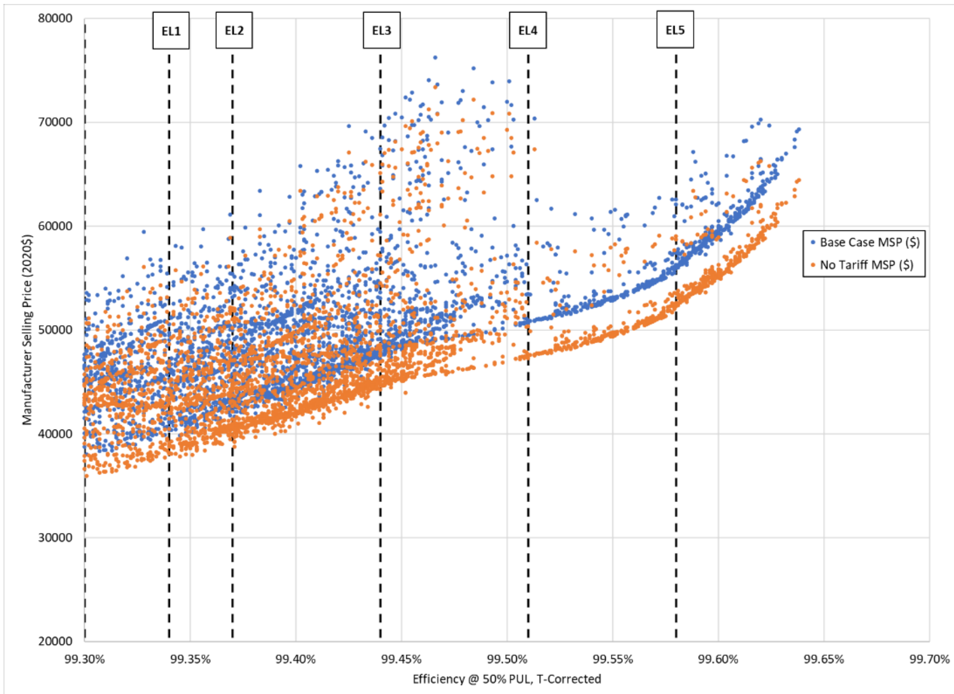


Figure 5B.2.23 No Tariff Material Price Comparison Plot, RU12

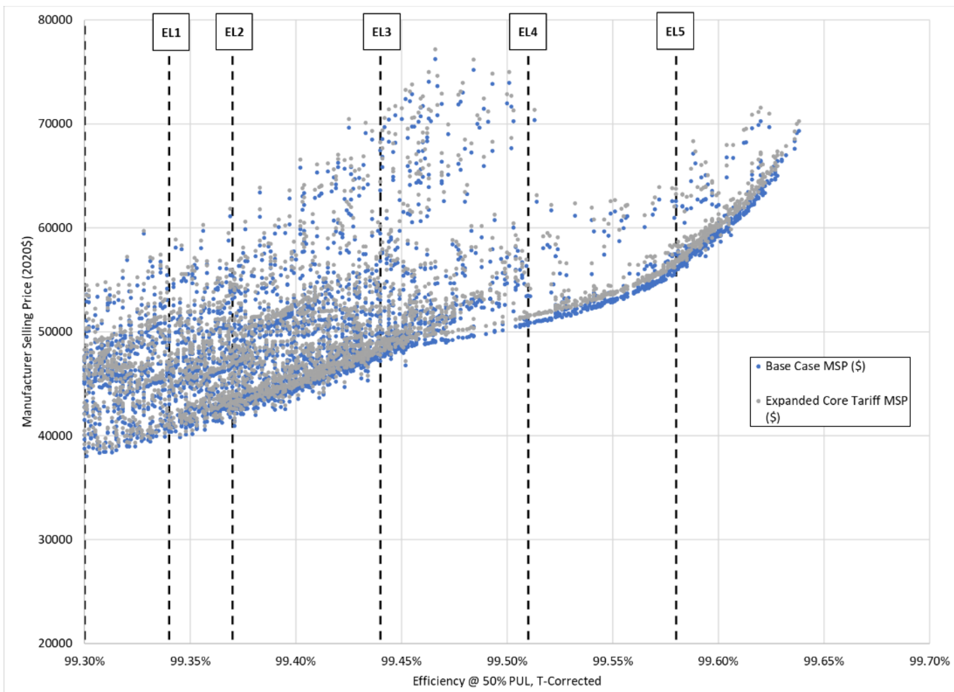


Figure 5B.2.24 Expanded Core Tariff Material Price Comparison Plot, RU12

5B.2.13 Representative Unit 13

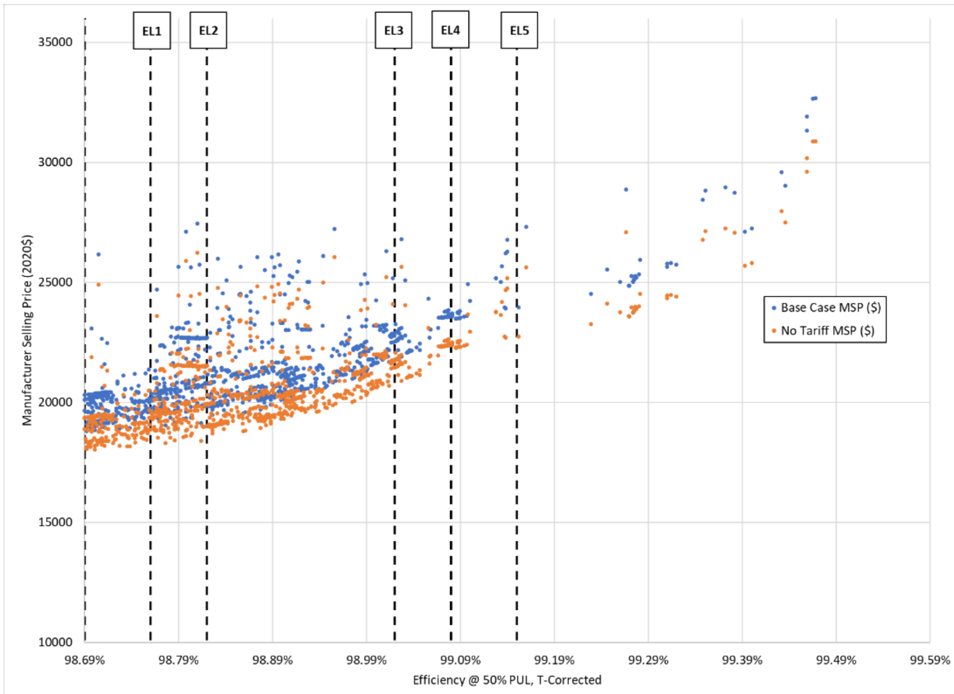


Figure 5B.2.25 No Tariff Material Price Comparison Plot, RU13

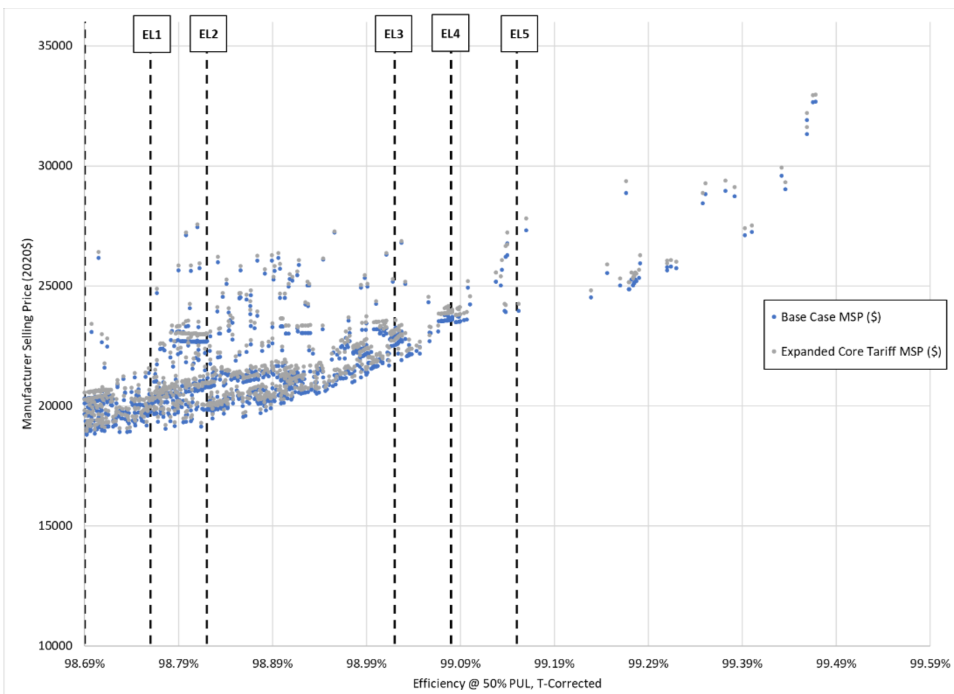


Figure 5B.2.26 Expanded Core Tariff Material Price Comparison Plot, RU13

5B.2.14 Representative Unit 14

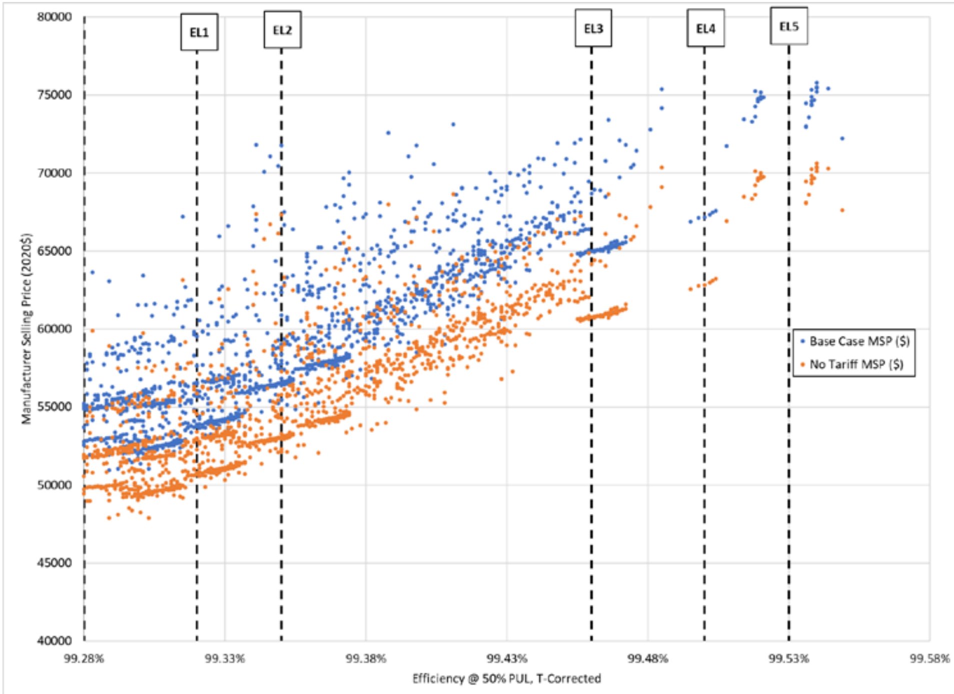


Figure 5B.2.27 No Tariff Material Price Comparison Plot, RU14

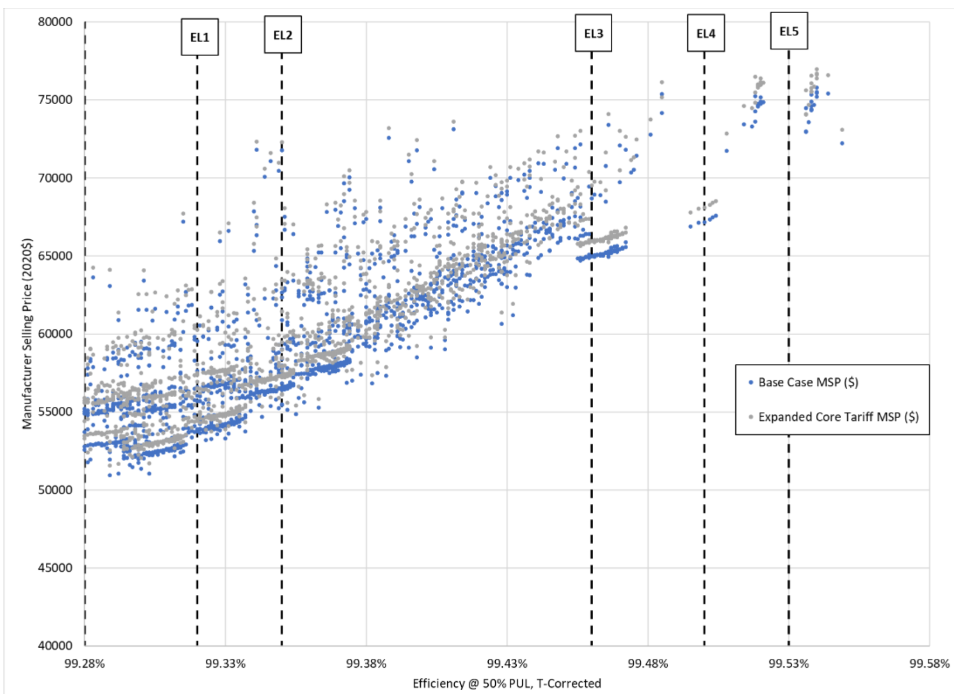


Figure 5B.2.28 Expanded Core Tariff Material Price Comparison Plot, RU14

APPENDIX 5C. SCALING RELATIONSHIPS IN TRANSFORMER MANUFACTURING

TABLE OF CONTENTS (STYLE TOC HEADING)

LIST OF TABLES (STYLE HEADING)

LIST OF FIGURES (STYLE HEADING)

APPENDIX 5C. SCALING RELATIONSHIPS IN TRANSFORMER MANUFACTURING

5C.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 5C.1.1 depicts the most common scaling relationships in transformers.

Table 5C.1.1 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 5C.1.1 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 5C.1.1 for reference.

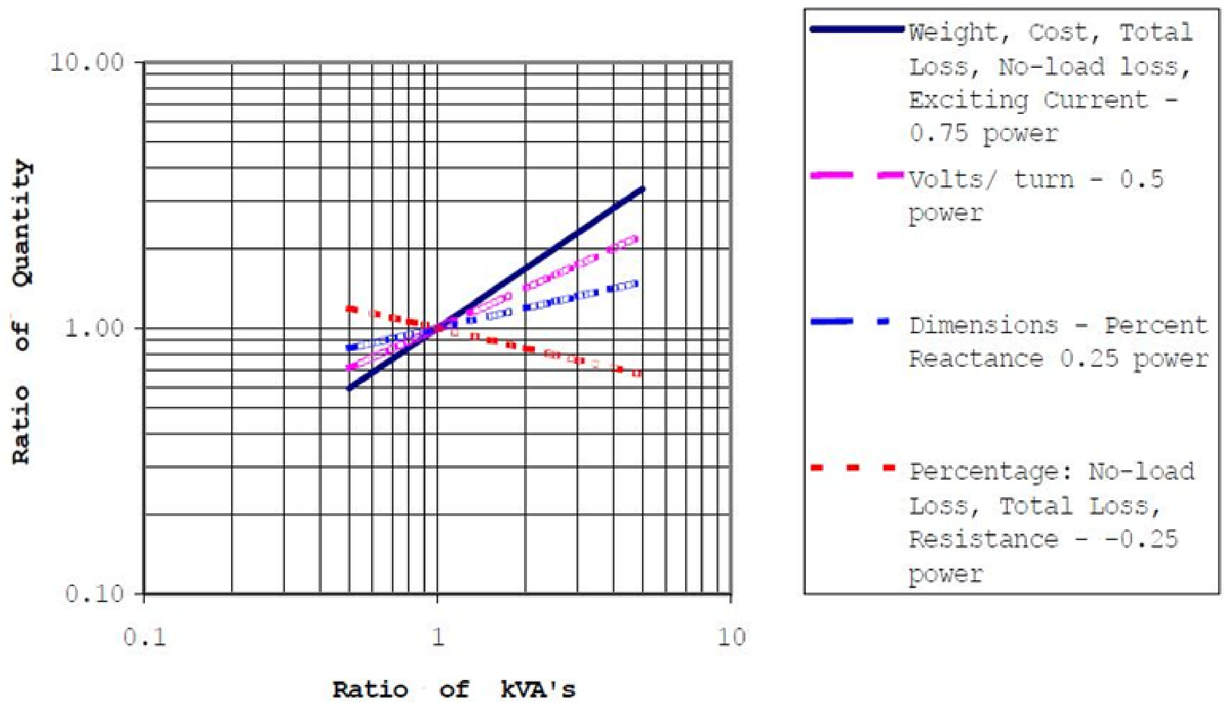


Figure 5C.1.1 Size and Performance Relationship by kVA Rating

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:

$$\mathrm{NL_1 = NL_0}\left(\frac{S_1}{S_0}\right)^{0.75} \quad \text{and} \quad \mathrm{TL_1 = TL_0}\left(\frac{S_1}{S_0}\right)^{0.75}$$

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:

$$\mathrm{LL_1 = TL_1 - NL_1}$$

Plugging the TL1 and NL1 terms into this equation:

$$\mathrm{LL_1 = TL_0}\left(\frac{S_1}{S_0}\right)^{0.75} - \mathrm{NL_0}\left(\frac{S_1}{S_0}\right)^{0.75}$$

$$= (\mathrm{TL_0 - NL_0})\left(\frac{S_1}{S_0}\right)^{0.75}$$

That is,

$$\mathrm{LL_1 = LL_0}\left(\frac{S_1}{S_0}\right)^{0.75}$$

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.

5C.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.[1] No mathematics beyond elementary algebra is required, but a good deal of implied physics and electrical engineering is required to fully appreciate these derivations.

5C.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

$$v = -N\frac{\partial \emptyset}{\partial t}$$

where v is the instantaneous value of V, and $\frac{\partial \emptyset}{\partial t}$ 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:

$$\mathrm{V/N = 4.44fB_m A_{Fe}}$$

Eq. 5CC.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,

$$\mathrm{V_1/V_2 = N_1/N_2 = n = I_2/I_1}$$

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 Eq. 5CC.1, the output or transformer capacity (S) in megavolt-amperes (MVA) per phase can be expressed as:

$$\mathrm{S = 4.44fB_m A_{Fe} NI}$$

Eq. 5CC.2

The overall cross-section of primary plus secondary conductors in square meters is

$$\mathrm{A_{Cu} = (N_1 a_1 + N_2 a_2) \times 10^{-6}}$$

and, assuming current densities for primary and secondary windings to be equal, then

$$\mathrm{A_{Cu} = 2 \times 10^{-6}\ Na}$$

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 Eq. 5CC.2, using the A_{Cu} relationship explained above, and letting J represent current density in amps per mm^2:

$$\mathrm{S = 2.22\ f\ B_m J A_{Fe} A_{Cu}}$$

Eq. 5CC.3

Let A_w be the core window area in square meters, and k_w the window space factor, as given by $\mathrm{2\ A_{Cu}/A_w}$. (Refer to Figure 5C.2.2 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,

$$S = 1.11\, f\, B_m J A_{Fe} k_w A_w$$

Eq. 5CC.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} α $1/A_{Cu}$.

5C.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,

$$\%\mathrm{Z} = \frac{\mathrm{IZ} \times 100}{\mathrm{V}}$$

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

$$\%\mathrm{Z} = \sqrt{(\%\mathrm{R})^2 + (\%\mathrm{X})^2}$$

Therefore, one can express percent resistance (%R) as follows:

$$\%\mathrm{R} = \frac{\mathrm{IR} \times 10^2}{\mathrm{V}}$$

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:

$$\text{Percent load loss} = \frac{\mathrm{I}^2\mathrm{R} \times 10^2}{\mathrm{I} \times \mathrm{V}} = \frac{\mathrm{I}^2\mathrm{R} \times 10^2}{3\mathrm{S} \times 10^6}$$

$$\therefore \%\mathrm{R} = \frac{10^{-4}\mathrm{P_t}}{3\mathrm{S}}$$

Thus, an expression of %R is equivalent to indicating the transformer's load loss.

From Eq. 5CC.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:

$$P_{Cu} = \left(1 + \frac{\%P_i}{100}\right) P_R = k_i P_R$$

$$P_{Cu} = \left({I_1}^2 R_1 + {I_2}^2 R_2\right) k_i,$$

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,

$$P_{Cu} = 2INJs\rho k_i$$

$$\therefore J = \frac{P_{Cu}}{2INs\rho k_i}, \text{ the current density equation.}$$

Multiplying Eq. 5CC.1 by I and rearranging algebraically, one gets:

$$\mathrm{IN} = \frac{\mathrm{VI}}{4.44 \mathrm{f} \mathrm{B_m} \mathrm{A_{Fe}}}$$

It was established earlier that S is the rating per phase in MVA, i.e., VI = 10^6S. Thus:

$$\therefore \mathrm{IN} = \frac{10^6 \mathrm{S}}{4.44 \mathrm{f} \mathrm{B_m} \mathrm{A_{Fe}}}$$

Using the current density equation, substituting the resistivity value for ρ, and the above value for IN, one can derive that:

$$\mathrm{J} = \frac{104 \times 10^{-6} \mathrm{f} \mathrm{B_m} \mathrm{A_{Fe}} \mathrm{P_{Cu}}}{\mathrm{k_i} \mathrm{s} \mathrm{S}}$$

The watts of conductor loss (for copper) can be expressed as a percentage of the transformer MVA rating:

$$\% \mathrm{P_{Cu}} = \frac{\mathrm{P_{Cu}} \times 10^2}{\mathrm{S}}$$

or, in kilowatts:

$$\% \mathrm{P_{Cu}} = \frac{\mathrm{P_{Cu}} \times 10^2}{\mathrm{S} \times 10^3} = \frac{0.1 \mathrm{P_{Cu}}}{\mathrm{S}}.$$

By substituting in the revised equation for J (amperes per square meter), one gets

$$\mathrm{J} = \frac{104 \times 10^{-6} \mathrm{f} \mathrm{B_m} \mathrm{A_{Fe}} \mathrm{S}}{\mathrm{k_i} \mathrm{s} \mathrm{S}} \times \frac{\% \mathrm{P_{Cu}}}{0.1} = \frac{1040 \times 10^{-6} \mathrm{f} \mathrm{B_m} \mathrm{A_{Fe}}}{\mathrm{k_i} \mathrm{s}} \times \% \mathrm{P_{Cu}}$$

Eq. 5CC.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.

5C.2.3 Output and Winding Coefficients

Starting with the output or power Eq. 5CC.3, one can write:

$$S = 2.22fB_mJA_{Fe}A_{Cu} \text{ or } A_{Fe} = \frac{S}{2.22fB_mJA_{Cu}}$$

Then, without changing the value, one can state:

$$A_{Fe} = \sqrt{\frac{S^2}{(2.22fB_mJA_{Cu})^2}} = \sqrt{S}\sqrt{\frac{2.22fB_mJ(A_{Fe})(A_{Cu})}{(2.22fB_mJA_{Cu})^2}} \text{ or}$$

$$A_{Fe} = \sqrt{S}\sqrt{\frac{A_{Fe}}{(2.22fB_mJ)(A_{Cu})}}$$

Eq. 5CC.6

Use K_{AS} to represent the portion of Eq. 5CC.6 to the right of $\sqrt{S}$

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 Eq. 5CC.6, we can restate Eq. 5CC.7 as follows:

$$\frac{V}{N} = 4.44fB_mA_{Fe} = \sqrt{\frac{(4.44fB_m)^2SA_{Fe}}{2.22fB_mJA_{Cu}}}$$

$$= \sqrt{\left(\frac{8.88fB_m}{J}\right)\left(\frac{A_{Fe}}{A_{Cu}}\right)(S)} = K_{VS}\sqrt{S}$$

Eq. 5CC.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}:

$$K_{VS} = 4.44fB_mK_{AS}$$

For 60 Hz systems, this may be rewritten as K_{VS}= 266.4 B_mK_{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. Eq. 5CC.6 and Eq. 5CC.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 5C.2.1.

Table 5C.2.1 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

5C.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 Table 5C.2.1 for dimensional definitions.

Now, one considers the load losses, P_{Cu} (in kW/phase):

$$P_{Cu} = \frac{I^2R}{1000} = \left(\frac{S}{V}\right)^2 \frac{R}{1000}$$

$$= \frac{4.28 \times 10^{-17} S^2 s N^2}{A_{Cu}V^2} = K\sqrt{S} \times s = K'S^{0.75}$$

The other scaling laws are derived in a similar fashion.

5C.2.5 Derivative from 0.75

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 Final Rule, 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 5C.2.2.

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 5C.2.1 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[a] 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.

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

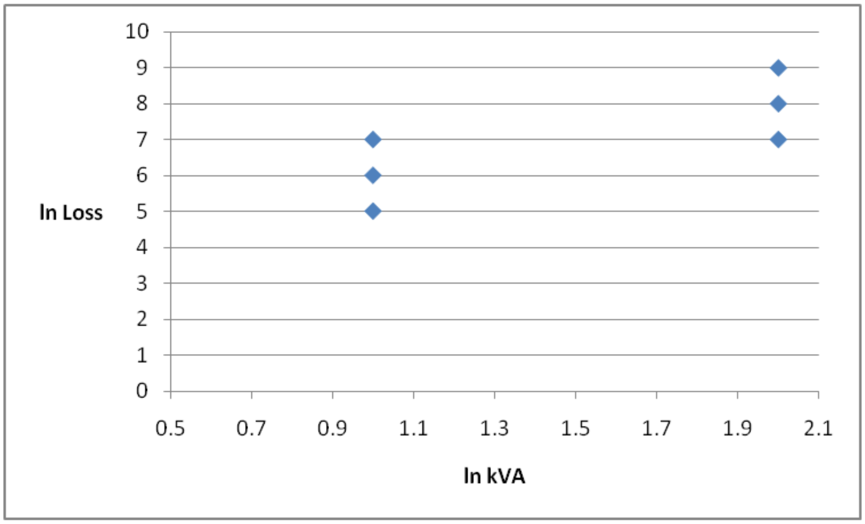
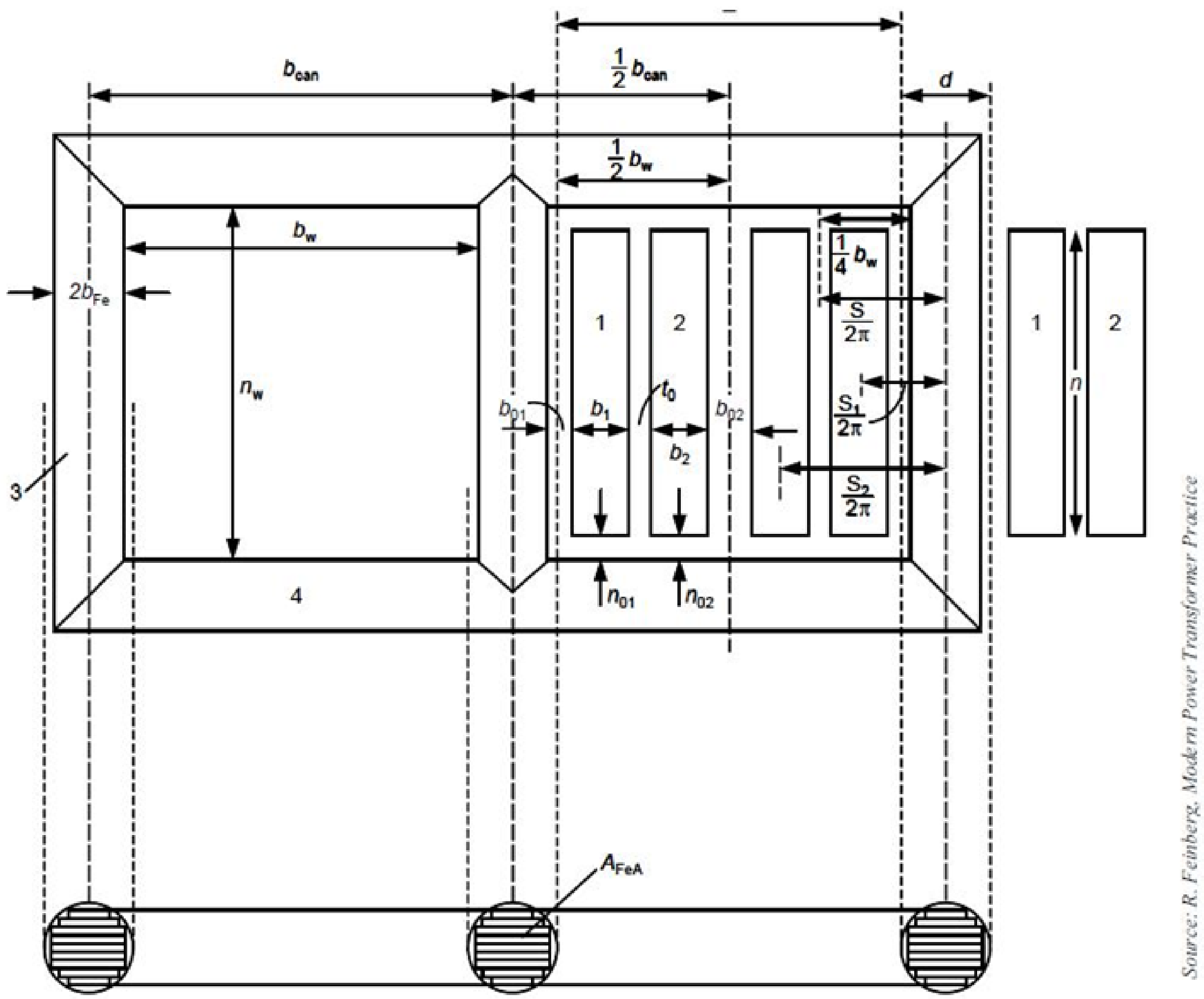


Figure 5C.2.1 Efficiency Levels within an Equipment Class (Logarithmic)

Table 5C.2.2 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	.74
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, ≥ 96 kV BIL	.68
10. Dry-type, medium-voltage, three-phase, ≥ 96 kV BIL	.68



Note: This diagram is not to scale

Figure 5C.2.2 Basic Three-Phase Transformer Dimensions

REFERENCES

1 Modern power transformer practice, Edited by R Feinberg, Wiley Publishers, New York, NY, 1979. ISBN: 047026344X

APPENDIX 7A. TECHNICAL ASPECTS OF THE ENERGY USE AND END-USE LOAD CHARACTERIZATION ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDIX 7A. TECHNICAL ASPECTS OF THE ENERGY USE AND END-USE LOAD CHARACTERIZATION ANALYSIS

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.1.1 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:

$$\boldsymbol{E_T} = \in_{\boldsymbol{NLL}} + \boldsymbol{E} + \in_{\boldsymbol{LL}} \left(\boldsymbol{E} / \boldsymbol{E_{max}} \right)^{\boldsymbol{2}}. \qquad \textbf{Eq. 7A.1.1}$$

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:

$$\boldsymbol{EC} = \boldsymbol{EC_{LL}} + \boldsymbol{EC_{NLL}} \qquad \textbf{Eq. 7A.1.2}$$

where EC_{NLL} is due to the no-load losses and EC_{LL} to the load losses. Because the no-load losses are flat,

$$\boldsymbol{EC_{NLL}} = \in_{\boldsymbol{NLL}} < \boldsymbol{p} > \mathbf{8760}, \qquad \textbf{Eq. 7A.1.3}$$

where <p> is the average over all hours of the hourly marginal production cost. For the load losses,

$$\boldsymbol{EC_{LL}} = \in_{\boldsymbol{LL}} \sum_{\boldsymbol{h}} \boldsymbol{p}(\boldsymbol{h})\, \boldsymbol{e}^{\mathbf{2}}(\boldsymbol{h}). \qquad \textbf{Eq. 7A.1.4}$$

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. 7A.1.4 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 $j = 1, \ldots N_S$ and $k = 1, \ldots N_T$. 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:

$$\boldsymbol{p}(\boldsymbol{h}) = \boldsymbol{f}(\boldsymbol{l}(\boldsymbol{h})). \qquad \textbf{Eq. 7A.1.5}$$

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:

$$\sum_{\boldsymbol{h}} \boldsymbol{p}(\boldsymbol{h})\, \boldsymbol{e}^{\mathbf{2}}(\boldsymbol{h}) = \sum_{\boldsymbol{j}} \sum_{\boldsymbol{k}} \boldsymbol{n_j p_j w_{jk} e_k^2}. \qquad \textbf{Eq. 7A.1.6}$$

7A.1.1.2 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, DOE calculated hourly time series for system loads and system prices based on 2015 hourly load and price data for individual utilities and control areas, obtained from Federal Energy Regulatory Commission (FERC) Form 714 filings.[a] 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:

$$\boldsymbol{p_j = \bar{p}_j + \delta_j}, \qquad \textbf{Eq. 7A.1.7}$$

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 7A.1.1 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 $\bar{l}_j$.

[a] For this analysis the 2015 prices were adjusted to the current analysis year of 2021 using the electricity price trends published in EIA's AEO 2021. Details are described in chapter 7 of this TSD.

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.1.1 Definition of EMM regions and NERC regions in terms of States

EMM	NERC	NERC Region	ISO Sub Region	Geographic Area
TRE	ERCO	Electric Reliability Council of Texas, Inc.		Texas
FRCC	FPL	Florida Reliability Coordinating Council, Inc.		Florida
MISW	MISO	Midcontinent Independent System Operator	West	Upper Mississippi Valley
MISC	MISO	Midcontinent Independent System Operator	Central	Middle Mississippi Valley
MISE	MISO	Midcontinent Independent System Operator	East	Michigan
MISS	MISO	Midcontinent Independent System Operator	South	Mississippi Delta
ISNE	ISNE	ISO New England Inc.	New England	New England
NYCW	NYIS	New York Independent System Operator	NYC & Long Island	Metropolitan New York
NYUP	NYIS	New York Independent System Operator	Upstate NY	Upstate New York
PJME	PJM	PJM Interconnection	East	Mid-Atlantic
PJMW	PJM	PJM Interconnection	West	Ohio Valley
PJMC	PJM	PJM Interconnection	Commonwealth Edison	Metropolitan Chicago
PJMD	PJM	PJM Interconnection	Dominion	Virginia
SRCA	VACS	VACAR-South	East	Carolinas
SRSE	VACS	VACAR-South	Southeast	Southeast
SRCE	TVA	Tennessee Valley Authority	Central	Tennessee Valley
SPPS	SPP	Southwest Power Pool	South	Southern Great Plains
SPPC	SPP	Southwest Power Pool	Central	Central Great Plains
SPPN	SPP	Southwest Power Pool	North	Northern Great Plains
SRSG	SPPW	Southwest Power Pool West	Southwest	Southwest
CANO	RCW	California Independent System Operator	CA North	Northern California
CASO	RCW	California Independent System Operator	CA South	Southern California
NWPP	RCW	California Independent System Operator	Northwest Power Pool	Northwest
RMRG	SPPW	Southwest Power Pool West	Rockies	Rockies
BASN	RCW	California Independent System Operator	Basin	Great Basin

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 system load bins, and highest near the average system load (i.e. 19,000 MWh?). The details of this relationship may differ in other regions. 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:

$$\boldsymbol{c_j = {}^{2}/_{(b_j + a_j)}}. \qquad \textbf{Eq. 7A.1.8}$$

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:

$$\boldsymbol{S_j^- = {}^{c_j a_j}/_{6}\,;\;\; S_j^+ = {}^{c_j a_j}/_{6}}, \qquad \textbf{Eq. 7A.1.9}$$

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.1.1.3 Joint Distribution of System and Transformer Loads

This section describes how DOE calculated the joint probability distribution function (JPDF) of transformer loads and system loads. For commercial and residential customers, the data set available at the time of this analysis was a set of 30-minute transformer loads from January 2018 to June 2019, and hourly system loads from 2020. The 30-minute loads were filtered for 2018 values to avoid any bias due to partial year data, and aggregated to hourly mean values for each transformer. In the case of industrial customers, actual transformer load data were not available. DOE assumed that the loads on individual industrial buildings would be similar in shape to the loads on individual transformers serving industrial customers. To estimate the relationship between load and the system from available hourly industrial customer data, DOE defined a (scaled) proxy system load as the sum of the individual industrial building loads.

The transformer loads were indexed by x, $e_x(h)$, x=1,..., M, where x indicates an individual transformer. For the transformers and the systems, each hourly load is scaled by its annual maximum, so that they all range in magnitude between zero and one. The relationship expressed by the function w_{jk}^{x} is the correlation between an individual load and the system load $s(h)$ of which the individual load is a part.

The function w_{jk}^{x} is estimated by distributing the hourly load pairs $\left(e_x(h), s(h)\right)$ into a set of N_T by N_S bins and counting the number of points in each bin for each transformer. The modeling steps are described in more detail below.

1. Construct the set of scaled data pairs$\left(s(h), e_x(h)\right), h = 1,2 \ldots, 8760$.
2. Define the bins for the system load s; these are identical to the bins used in the system load analysis described in section 7A.1.1.2 above. There are N_S bins having index j. In this case, N_S was selected as 15.
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 $1/N_T$. N_T was selected as 10.
4. Count the number of points (j, k) in each bin; this count is defined as m_{jk}^{x}.
5. Divide m_{jk}^{x} for all the transformer load time series by total number of data pairs, 8760, to convert the count to a probability for each transformer:

$$\boldsymbol{w_{jk}^{x} = \left(\frac{1}{8760}\right)\left(\frac{1}{M}\right)\sum_{x} m_{jk}^{x}}. \qquad \textbf{Eq. 7A.1.10}$$

The number w_{jk}^{x} is an estimate of the probability of finding a transformer load in bin k, given a system load in bin j, for transformer x. 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.

Because the correlation between system and transformer loads varies by customer sector, JPDFs were calculated separately for residential, commercial and industrial consumers. DOE then assigned a load size category, small and large, for each JPDF to better align the statistical models with the design lines developed as inputs for the engineering analysis. For commercial and residential customers, the transformer was categorized as for a large customer if the transformer's capacity exceeded 150 kVA; otherwise it was categorized as for a small customer. No transformer capacity information was available to the Department for industrial customers; therefore, the load size category was randomly distributed among all the JPDFs for industrial customers. To make use of multiple years of building data for industrial customers, DOE estimated w_{jk} from the combined three-year time series from the "Duckett", "ELCAP" and "Dominion" data sets. For commercial and residential customers, the data was only available for the year 2018.

An example of the output is shown in Figure 7A.1.1 through Figure 7A.1.5. These shows the JPDFs calculated for all the customers served by each representative unit, with system load bins on the horizontal axis and 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 lower bin indices correspond to lower load levels. The figure shows that, for low system loads, transformer loads are distributed broadly, whereas for higher system loads transformer loads are more correlated with system load.

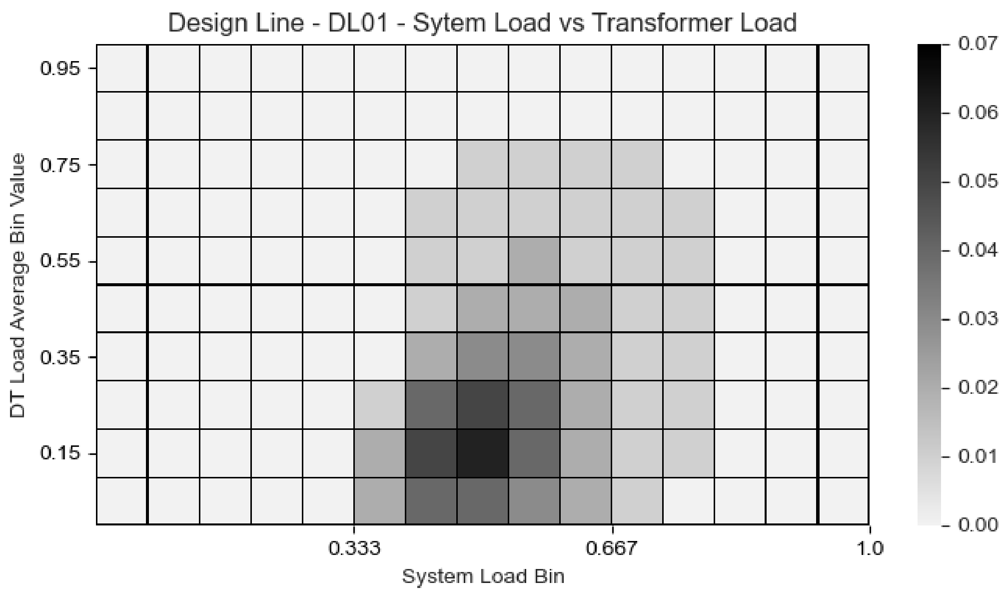


Figure 7A.1.1 Correlation Coefficients for Different System Load and Transformer Load for all Sectors for Rep Unit 2

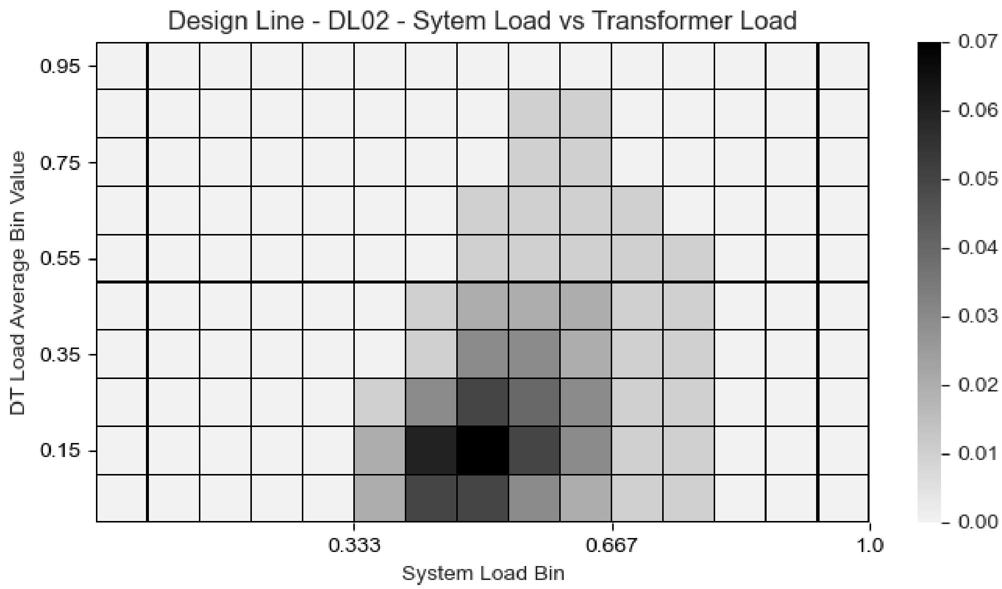


Figure 7A.1.2 Correlation Coefficients for Different System Load and Transformer Load for all Sectors for Rep Unit 2

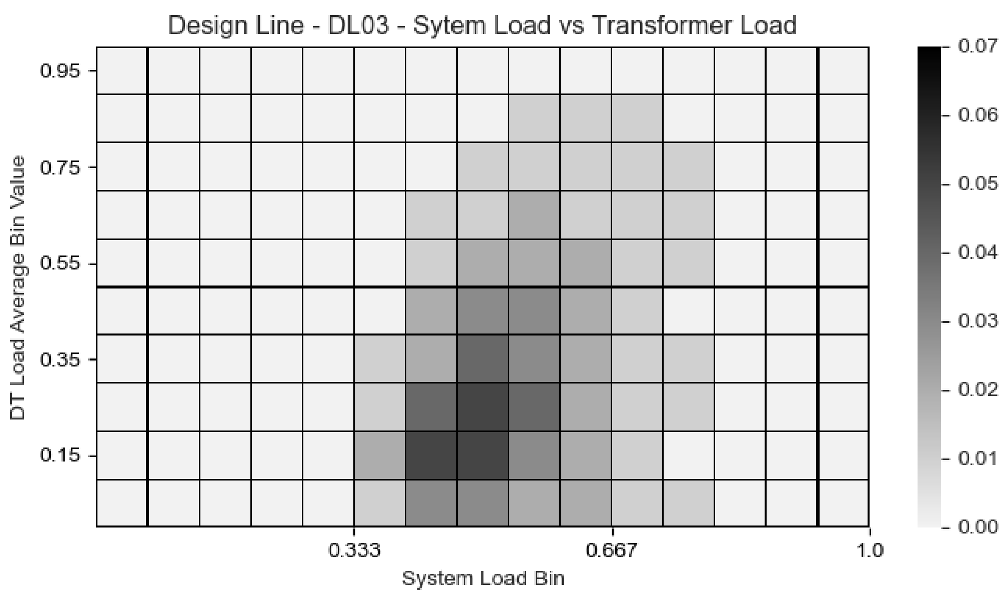


Figure 7A.1.3 Correlation Coefficients for Different System Load and Transformer Load for all Sectors for Rep Unit 3

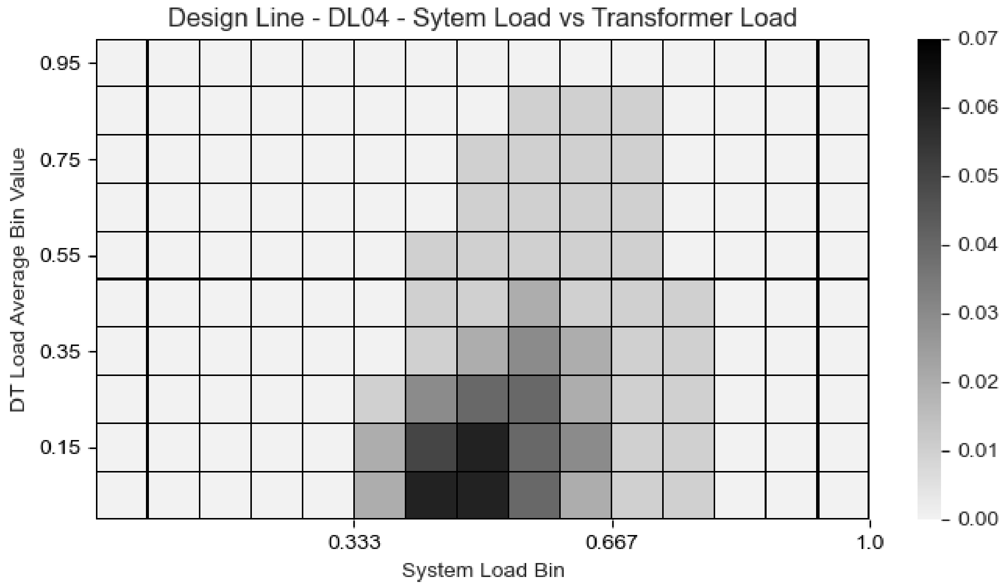


Figure 7A.1.4 Correlation Coefficients for Different System Load and Transformer Load for all Sectors for Rep Unit 4

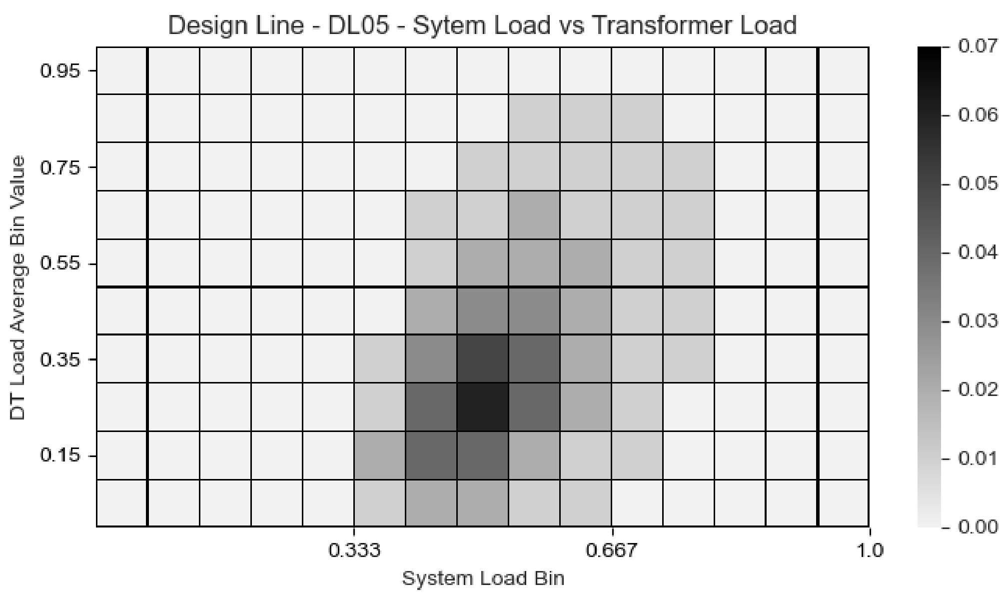


Figure 7A.1.5 Correlation Coefficients for Different System Load and Transformer Load for all Sectors for Rep Unit 5

There were insufficient data to validate the JPDF directly. DOE 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.[b] The tests showed that the JPDF is insensitive to the subset of buildings chosen as long as about 100 buildings or more are used.

7A.1.1.4 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:

$$\boldsymbol{r_k} = \boldsymbol{w_{N_S,k}} \Big/ \textstyle\sum_{\boldsymbol{k}} \left(\boldsymbol{w_{N_S,k}}\right). \qquad \textbf{Eq. 7A.1.11}$$

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 reasonable estimate of the distribution of the responsibility factor.

7A.2 LOADING ANALYSIS FOR DRY-TYPE TRANSFORMERS

This section 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:

$$\Delta B = (\Delta E_{LL} + \Delta E_{NLL}) \times MPE + (\Delta D_{LL} + \Delta D_{NLL}) \times MPD \qquad \textbf{Eq. 7A.2.1}$$

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]);

MPD = the marginal price for building electricity demand ($/kW)

[b]The L1 norm is equal to the absolute value of the difference between the two functions.

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.2.2 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:

$$\Delta E_{NLL} = (NLL_{BaseCase} - NLL_{StandardsCase}) \times HPY \qquad \textbf{Eq. 7A.2.2}$$

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.2.3 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.2.4 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:

$$\Delta \boldsymbol{E_{LL}} = (\boldsymbol{LL_{BaseCase}} - \boldsymbol{LL_{StandardsCase}}) \times \left[\sum \boldsymbol{h} \left(\frac{\boldsymbol{L(h)}}{\boldsymbol{PL}}\right)^{\mathbf{2}}\right] \times \left(\frac{\boldsymbol{PL}}{\boldsymbol{CAP}}\right)^{\mathbf{2}} \qquad \textbf{Eq. 7A.2.3}$$

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.

Equation 7A.3.3 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:

$$\boldsymbol{LSF_M} = \frac{\left[\sum \boldsymbol{h}\left(\frac{\boldsymbol{L(h)}}{\boldsymbol{PL}}\right)^{\mathbf{2}}\right]}{\boldsymbol{NH}}$$

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 8760/12

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]

$$LSF = \alpha \times LF + (1-\alpha) \times LF^2$$

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:

$$\boldsymbol{\alpha} = \frac{\boldsymbol{LSF - LF^2}}{\boldsymbol{LF - LF^2}} \qquad \textbf{Eq. 7A.2.4}$$

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 ($0 < LF_M \leq .33$), medium ($.33 < LF_M \leq .67$), and high ($.67 < LF_M \leq 1$). The distributions are shown in Figure 7A.2.2.

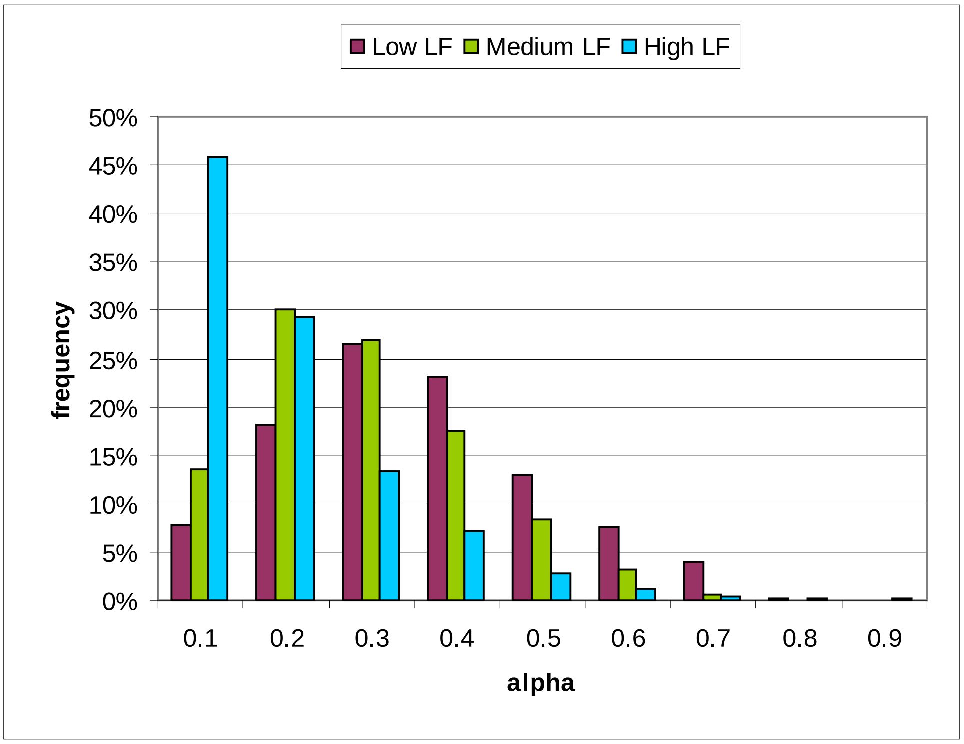


Figure 7A.2.2 Frequency Distributions for the LSF

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 7A.2.1 are used to select a value of α, and Eq. 7A.2.4 is used to estimate the loss factor.

7A.2.4.2 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:

$$\Delta \boldsymbol{D_{LL}} = (\boldsymbol{LL_{BaseCase}} - \boldsymbol{LL_{StandardsCase}}) \times \left(\frac{\boldsymbol{L(hmax)}}{\boldsymbol{PL}}\right)^{\boldsymbol{2}} \times \left(\frac{\boldsymbol{PL}}{\boldsymbol{CAP}}\right)^{\boldsymbol{2}} \qquad \textbf{Eq. 7A.2.5}$$

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:

$$\Delta \boldsymbol{D_{LL}} = (\boldsymbol{LL_{BaseCase}} - \boldsymbol{LL_{StandardsCase}}) \times \boldsymbol{CPL^2} \times \left(\frac{\boldsymbol{PL}}{\boldsymbol{CAP}}\right)^{\boldsymbol{2}} \qquad \textbf{Eq. 7A.2.6}$$

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 of the peak aggregate load (*hmax*).
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 7A.2.2, which shows the cumulative distribution function for *CPL* as well as several powers of *CPL*.

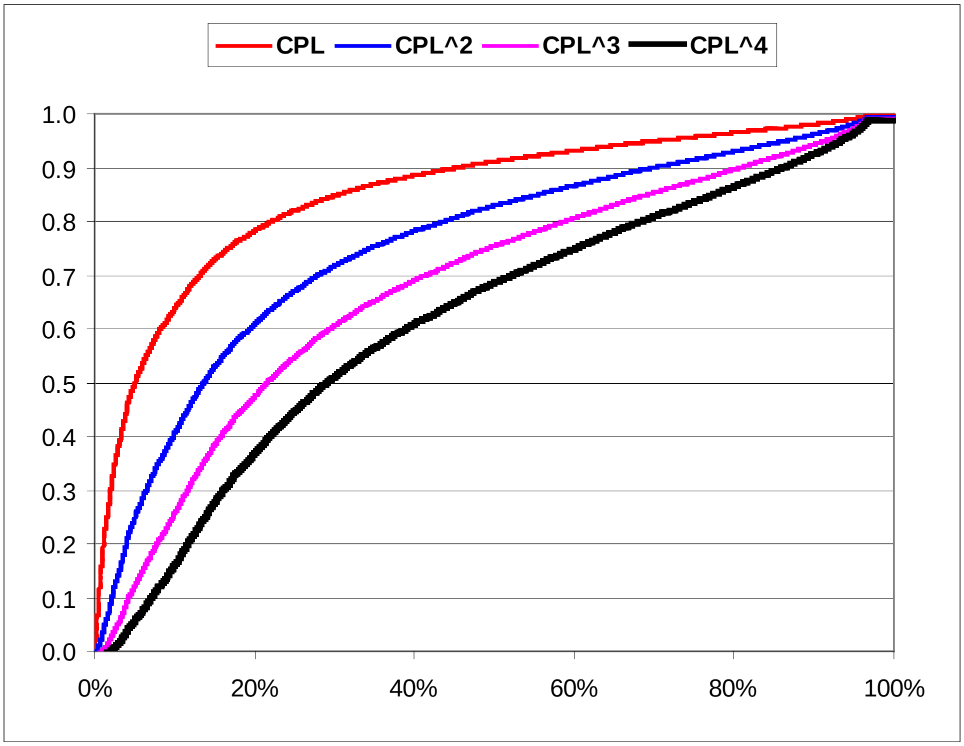


Figure 7A.2.3 Cumulative Distribution Function for the Coincident Peak Load

Roughly 80 percent of the *CPL* values in the sample are greater than 0.8 (indicated by the red line in Figure 7A.2.2). 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 black line in figure 7A.3.3); 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 7A.2.2.
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.

REFERENCES

1. Energy Information Administration - Office of Integrated Analysis and Forecasting. *The National Energy Modeling System (NEMS): An Overview*. (U.S. Department of Energy, 2009). at <http://www.eia.doe.gov/oiaf/aeo/overview/>

2. Coughlin, K., Bolduc, C., Van Buskirk, R., Rosenquist, G. & McMahon, J. E. *Tariff-based Analysis of Commercial Building Electricity Prices*. (Lawrence Berkeley National Laboratory, 2008).

3. M. E. de Oliveira, A. Padilha-Feltrin & F. J. Candian. Investigation of the Relationship between Load and Loss Factors for a Brazilian Electric Utility. in (IEEE, 2006). doi:10.1109/TDCLA.2006.311390

4. U.S. Department of Energy-Energy Information Administration. Form EIA-861: Annual Electric Power Industry Database. (2008). at <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

5. U.S. Department of Energy-Federal Energy Regulatory Commission. *Form No. 714 - Annual Electric Control and Planning Area Report*. (U.S. Department of Energy-Federal Energy Regulatory Commission, 2015). at <http://www.ferc.gov/docs-filing/forms/form-714/overview.asp>

6. The California Independent System Operator (CAISO). The California ISO Open Access Same-time Information System (OASIS). at <http://oasis.caiso.com>

7. Open Access Same-time Information System. PacifiCorp hourly pricing proxy. at <http://www.oasis.pacificorp.com/oasis/ppw/OasisProxyPricing.xls>

8. ERCOT. (2010). at <http://www.ercot.com>

9. North American Electirc Reliability Corporation. Regional Entities. (2010). at <http://www.nerc.com/page.php?cid=1|9|119>

10. U.S. Department of Energy – Energy Information Administration. Building Technologies Program: EnergyPlus Energy Simulation Software. at <http://apps1.eere.energy.gov/buildings/energyplus/>

11. U.S. Census Bureau. Census Regions and Divisions of the United States. (2000). at <http://www.census.gov/geo/www/us_regdiv.pdf>

APPENDIX 7B. SAMPLE UTILITIES

TABLE OF CONTENTS

LIST OF TABLES

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

EMM Region		Control Area Operator		Utility	
ID	Name	ID	Name	ID	Name
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

EMM Region		Control Area Operator		Utility	
ID	Name	ID	Name	ID	Name
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

EMM Region		Control Area Operator		Utility	
ID	Name	ID	Name	ID	Name
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

EMM Region		Control Area Operator		Utility	
ID	Name	ID	Name	ID	Name
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

REFERENCES

1. Energy Information Administration - Office of Integrated Analysis and Forecasting *The National Energy Modeling System*. (U.S. Department of Energy: Washington DC, 2009).at <http://www.eia.doe.gov/oiaf/aeo/overview/>

APPENDIX 7C. DATA DESCRIPTION AND EXPLORATORY ANALYSIS OF INDUSTRY PROVIDED TRANSFORMER LOAD DATA

TABLE OF CONTENTS

LIST OF FIGURES

APPENDIX 7C. DATA DESCRIPTION AND EXPLORATORY ANALYSIS OF INDUSTRY PROVIDED TRANSFORMER LOAD DATA

7C.1 TRANSFORMER DATASET

This section provides technical details regarding the methodologies implemented by the U.S. Department of Energy (DOE) to study industry provided load data associated with liquid-immersed transformers. The load data provided was estimated by aggregation of ratepayer advanced metering infrastructure (AMI) data, in lieu of meter readings generated directly by the transformers. These meters served residential and commercial customers in Virginia and North Carolina. The estimation of transformer load was performed by the industry stakeholder prior to the data being made available to DOE. Therefore, DOE did not have any insight into the methodology employed in the aggregation of the AMI data. It was, however, ensured to DOE that the individual meters were randomly selected.

The dataset itself was provided to DOE in comma-separated values (CSV) format, including columns for alphanumeric transformer identifier, timestamp, and load readings. The load values were reported in kWh units in 30-minute intervals for 61,267 transformers. For 93% of the transformers, the beginning and end dates of the load readings were January 01, 2018 and June 20, 2019, respectively. The remainder had readings between those days. The discrepancies in meter reading start and end dates could be attributed partly to commissioning and decommissioning of customer meters over time, and partly to missing data. DOE decided to only use the data for transformers for which data was available for all of 2018 to avoid any bias in the analysis due to incomplete data for 2019.

7C.1.1 Supplementary Dataset

In addition to the load associated with the transformer, DOE was provided with some characteristics of the transformers as well. This transformer metadata included the following:

1. ZIP Code: 5 digit US postal code. Excluding incorrect information, the transformers were available in more than 1,180 zip codes.

2. Bank Rating in kVA: Transformer bank is a group of transformers, and the bank rating is the sum of the ratings of the individual transformers within a bank. The rating indicates the capacity of the transformer bank.

3. Phases: Indicator for transformer phases, varying between 1, 2 or 3 phases.

4. No. of Units: Count of transformers forming the bank.

5. Location Flag: Indicator for the installed location of the transformer, overhead or underground.

6. Count of Customers: Count of Residential, Commercial, Industrial, and Agricultural customers per transformer, however no transformer was found to serve Industrial and Agricultural customers in the dataset.

Not all transformer metadata was available for every transformer, further, DOE only received AMI data for a subset of transformers. The Zip Code was available for 646,041 transformers. For 591,108 transformers, both specifications and customer information are available. All of the metadata along with the AMI load data was available for only 61,123 transformers. This smaller subset of transformers were located in 152 zip codes.

DOE also categorized each transformer based on its end-use by sector. Transformers were categorized as “Residential”, “Commercial” or “Mixed”, based on the percentage of commercial customers out of total customers, referred to as $Percentage_{Commercial\ Customers}$. The conditions for categorizing were:

1. Residential: $0\% \leq Percentage_{Commercial\ Customers} \leq 30\%$
2. Mixed: $30\% < Percentage_{Commercial\ Customers} < 70\%$
3. Commercial: $70\% \leq Percentage_{Commercial\ Customers} \leq 100\%$

7C.2 IDENTIFICATION OF OUTLIERS

This section presents the methodology employed by DOE to identify and filter outlier load values from the dataset. As an initial check, the load values where checked for presence of any null values for each transformer. No null values were observed, thereby forgoing the need for any imputation of values. Following this check, DOE calculated the maximum values for each transformer and compared them with the bank rating of the transformer. It was theorized by the Department that extremely large values would have a material impact on the JPDF with the system load. After multiple trials and careful experimentation, DOE marked as outlier and removed transformers for which the percentage difference between the 95th percentile load value and the bank rating was greater than or equal to 130%.

Additionally, DOE encountered certain transformers for which most load observations were close to 0 kWh. Such transformers, for which the percentage difference between maximum load and bank rating was -100%, were also considered to be outliers by the Department, and were filtered from the analysis. DOE also marked as outliers those transformers which had maximum load as a very small non-zero value. Transformers for which the percentage difference between maximum load and bank rating was -96%, were also filtered from the analysis.

As a result, all of the data from 2,381 transformers, or 3.9% of all transformers and x% of all 30-minute data, were marked as outliers and excluded from the analysis.

7C.3 IDENTIFYING SYSTEM LOAD FOR THE TRANSFORMERS

This section describes the analysis DOE performed to determine the system load associated with the transformers. The following steps were taken to identify in which system each transformer was located:

1. Identification of geospatial boundaries of the 152 ZIP codes for which complete transformer load data was available: This was performed by obtaining ZIP code shapes from US Census.[a] It was observed that most of the ZIP codes belonged to PJM Interconnection's Dominion Hub.

2. Estimation of spatial bounds of the Dominion Hub region: DOE could not find any geospatial information that described the bounds of the Dominion Hub. Therefore, DOE estimated the bounds of the region, as described in section 7C.3.1.

3. Determination of ZIP codes in the Dominion Hub region: Once the spatial bounds of the Dominion Hub region were estimated, DOE excluded ZIP codes which did not belong in the region, as explained in section 7C.3.2.

4. Obtaining system load: Load for the Dominion Hub, henceforth referred to as the system load, was downloaded by the Department from the official PJM website.[b] The system load contains energy demand values in MW at hourly timestamps. No missing values were observed in the dataset. DOE assumed the MW values downloaded from PJM's website to be correct, and did not perform an outlier detection analysis for them.

7C.3.1 Estimating Spatial Bounds of PJM Interconnection's Dominion Hub Region

A mapping of ZIP codes to ISO regions was required to identify which of the 152 ZIP codes are located in in the Dominion Hub region; however, DOE did not identify any dataset with such details. While the spatial boundaries of ZIP codes are publicly available, the boundary of the Dominion Hub is not; therefore DOE estimated the spatial boundary of the Dominion Hub region using a different method.

Based on a visual inspection, it was observed that Dominion Hub was approximately formed of the region at the intersection of the PJM Interconnection and SERC Reliability Corporation/Virginia-Carolina (SRVC) regions. Geographical boundaries for Independent System Operators,[c] and NERC Regions[d] were obtained from Homeland Infrastructure Foundation-Level Data (HIFLD). The former contained the geometry of PJM Interconnection, and the latter described the SRVC region. An intersection of the two geometries was performed to obtain the approximate region of Dominion Hub.

---

[a] Available from: https://www2.census.gov/geo/tiger/TIGER2016/ZCTA5/
[b] Available from: https://dataminer2.pjm.com/feed/hrl_load_metered
[c] Available from: https://hifld-geoplatform.opendata.arcgis.com/datasets/9d1099b016e5482c900d657f06f3ac80_0/data
[d] Available from: https://hifld-geoplatform.opendata.arcgis.com/datasets/6b2af23c67f04f4cb01d88c61aaf558a_0

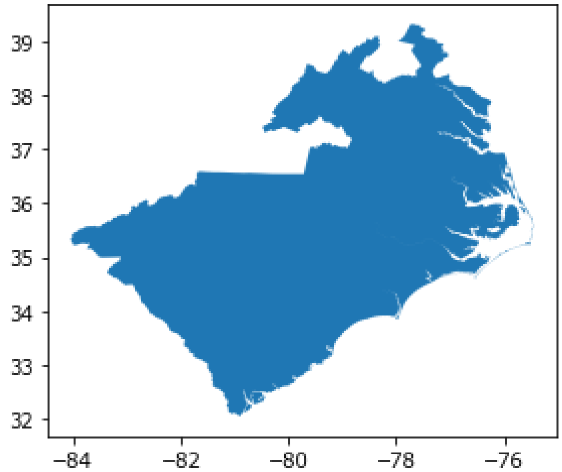


Figure 7C.3.1 SERC Reliability Corporation/Virginia-Carolina (SRVC) Region

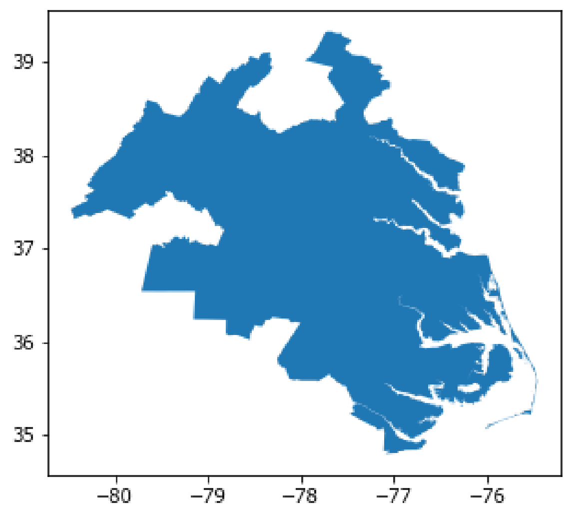


Figure 7C.3.2 Approximate Dominion Hub region formed by intersection of PJM Interconnection and SRVC Regions

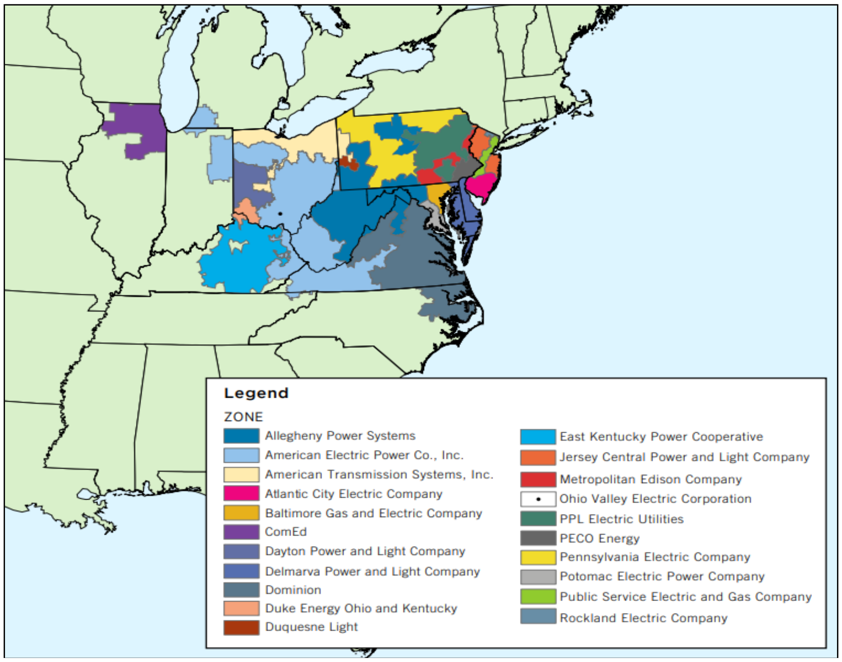


Figure 7C.3.3 Zones within PJM Interconnection (with Dominion Hub region marked in gray)[e]

7C.3.2 Identifying ZIP Codes in the Dominion Hub Service Territory

To obtain the list of ZIP codes in this approximate Dominion Hub region, DOE used a three-step process.

1. Geometries of transformer ZIP codes available in the US Census data were overlapped with the approximate Dominion Hub region to identify which transformer ZIP codes lay within the Dominion Hub region.

2. For any ZIP code with no information in the US Census data, the US Postal Service (USPS) API was queried to obtain the city and state associated with that ZIP code. However, not all ZIP codes could be queried from the USPS API. Note that sometimes large buildings can have their own ZIP codes.

3. The list of the city and state was uploaded to GeoCode.io to obtain the approximate latitude and longitude of each city and state. From the coordinates, DOE was able to identify which locations belonged within the Dominion Hub region.

[e] Source: https://www.pjm.com/-/media/about-pjm/pjm-zones.ashx?la=en, and https://www.pjm.com/about-pjm/who-we-are/territory-served.aspx

Using this methodology, DOE observed that out of the 152 ZIP codes with complete transformer data, 127 ZIP codes belonged in the approximate Dominion Hub region. DOE formed joint probability distribution functions between the transformers in these 127 ZIP codes and the Dominion Hub system load, with details in Appendix 7-A.

REFERENCES

1. United States Census Bureau. TIGER/Line Shapefiles. (2016). at <https://www2.census.gov/geo/tiger/TIGER2016/ZCTA5>

2. PJM . Hourly Load: Metered. at <https://dataminer2.pjm.com/feed/hrl_load_metered/definition>

3. Homeland Infrastructure Foundation-Level Data (HIFLD). Independent System Operators. at < https://hifld-geoplatform.opendata.arcgis.com/datasets/9d1099b016e5482c900d657f06f3ac80_0>

3. Homeland Infrastructure Foundation-Level Data (HIFLD). NERC Regions. at < https://hifld-geoplatform.opendata.arcgis.com/datasets/6b2af23c67f04f4cb01d88c61aaf558a_0>

4. PJM. Territory Served. at <https://www.pjm.com/-/media/about-pjm/pjm-zones.ashx?la=en>

APPENDIX 7D. IMPACT OF NEW DATA SOURCE ON JOIN PROBABILITY DISTRIBUTION FUNCTIONS

TABLE OF CONTENTS

LIST OF FIGURES

APPENDIX 7D. IMPACT OF NEW DATA SOURCE ON JOIN PROBABILITY DISTRIBUTION FUNCTIONS

7D.1 INTRODUCTION

DOE received a dataset of 30 minute loads for over 60,000 individual in 2018; this type of data was unavailable for the previous rulemaking. This appendix provides the methodology of how these data were prepared and applied to the consumer impacts estimates. In the previous rule DOE had obtained small meter-level datasets were available for two regions - the Pacific Northwest (PNW), and North and South Carolina (NSC). From these datasets DOE was able to construct joint probability distribution functions (JPDFs) of transformer loads as a function and system loads for residential, commercial and industrial customers.

For this analysis DOE combined the 2018 30-minute load data with the data from the two regions used in the previous rulemaking, to generate 100 JPDFs for both the commercial and residential sectors. These JPDFs were created on a sectoral level as opposed to individual transformer JPDFs, using steps described in Appendix 7-A. JPDFs for these sectors were also generated using the older PNW and NSC datasets. These JPDFs from the three data sources were then applied to system loads obtained from FERC to generate individual transformer loads. DOE compared this new approach with its previous approach and observed no substantial differences between the JPDFs obtained from the prior and new datasets.

7D.2 RECREATING JOINT PROBABILITY DISTRIBUTION FUNCTIONS USING THE PREVIOUS DATASETS

7D.2.1 Pacific Northwest Dataset

The Pacific Northwest (PNW) dataset contained hourly meter load data for 55 commercial and 256 residential buildings. The load data was available for two years, 1987 and 1988. The dataset also contained a measure of data quality *i.e.* the ratio of hourly load values with no issues to total hourly values. DOE defined data issues as either loads that were zero or loads that were several times the maximum capacity of the connected transformer. The PNW dataset was filtered for meters where this ratio was greater than 0.75 to balance data quality with quantity.

To obtain a sample of commercial and residential loads DOE scaled the PNW load data so the ratio of commercial to residential annual energy use matched that from EIA's 1987 published data. This ratio was calculated to be approximately 0.8824. PNW's commercial hourly loads were scaled to achieve this ratio for both 1987 and 1988.

The system load for PNW was estimated by aggregating the scaled commercial loads with the residential loads, for every hour of each year. This PNW system load was then scaled by the yearly maximum value, so that the system load ranged from 0 to 1. This scaling by annual maximum value was also performed for individual meter loads.

Separate JPDFs were then created for the commercial and residential sectors, using the same bins and process described in Appendix 7A.

7D.2.2 Joint Probability Function from North and South Carolina Dataset

The North and South Carolina (NSC) dataset contained hourly loads for commercial and industrial buildings over a three year period from 1998 to 2000. Along with the building load, DOE was also provided with the Federal Energy Regulatory Commission (FERC) system load for the regions these buildings belonged to. For both system and building loads, the hourly load values were scaled by their annual maximum values.

To create commercial JPDFs, DOE filtered the NSC data for 245 *office*, *retail*, *restaurant*, *lodging*, *education*, and *grocery* properties. The load was also scaled for these 245 buildings, and joined with the scaled system load. To create industrial JPDFs, the remaining property types (i.e. *food, furniture, industrial machines, metal fabrication, miscellaneous commercial*, *miscellaneous industrial*, *rubber and plastics*, and *textile*) were used. The method described in Appendix 7-A was used again to estimate separate JPDFs for the commercial and industrial sectors.

7D.3 CREATING 100 JPDFS BY RANDOMLY SAMPLING TRANSFORMER DATA

In order to represent the commercial and residential loads in the PNW dataset, DOE drew 100 random samples of 55 commercial and 256 residential transformers. For each sample, the ratio of annual commercial load to annual residential load was calculated. The transformer loads were scaled such that the ratio of their annual total matches the 1987 EIA ratio mentioned above. The system load for each sample was generated by adding the loads of all transformers for each hour. Both transformer loads and the system loads were scaled by their annual maximum values. These scaled loads were then used to generate 100 different samples of PNW commercial and residential JPDFs.

To create a dataset comparable to the NSC data, DOE drew 100 samples of 245 random transformers serving commercial customers. Their hourly loads were scaled by their annual maximum load values. In this case, the Dominion Hub load was used as the system load. Using the transformer and system loads, 100 different samples of NSC JPDFs were created, one for each trial.

7D.4 APPLYING JPDFS TO ACTUAL SYSTEM LOADS AND GENERATING TRANSFORMER LOADS

After developing the sector level JPDFs from the three data sources, DOE investigated if there were material differences between them. For comparison, DOE generated actual system load data for the Pacific Northwest and North/South Carolinas regions using FERC's Form 714. Actual system load for the Pacific Northwest was calculated by summing hourly values for Portland General Electric Company, PacifiCorp – West, and Bonneville Power Administration. The system load for the Carolinas was calculated using the data from Progress Energy (Carolina Power & Light Company), Duke Energy Corp., Duke Energy Carolinas, South Carolina Electric & Gas, and South Carolina Public Service Authority.

Using the actual Pacific Northwest system load, and the PNW JPDF, a year's worth of hourly transformer load values were generated. Using the same system load but the 100 copies of PNW JPDFs, a set 100 of annual transformer loads for commercial and residential sectors was generated. Histograms of transformer values from the actual vs the copied JPDFs were then created for the residential and commercial sectors.

A similar set of steps were taken using the Carolinas data to generate distribution of transformer values using the NSC JPDFs, and 100 samples of the NSC JPDFs. Note that in this case only commercial sector JPDFs were derived from each source.

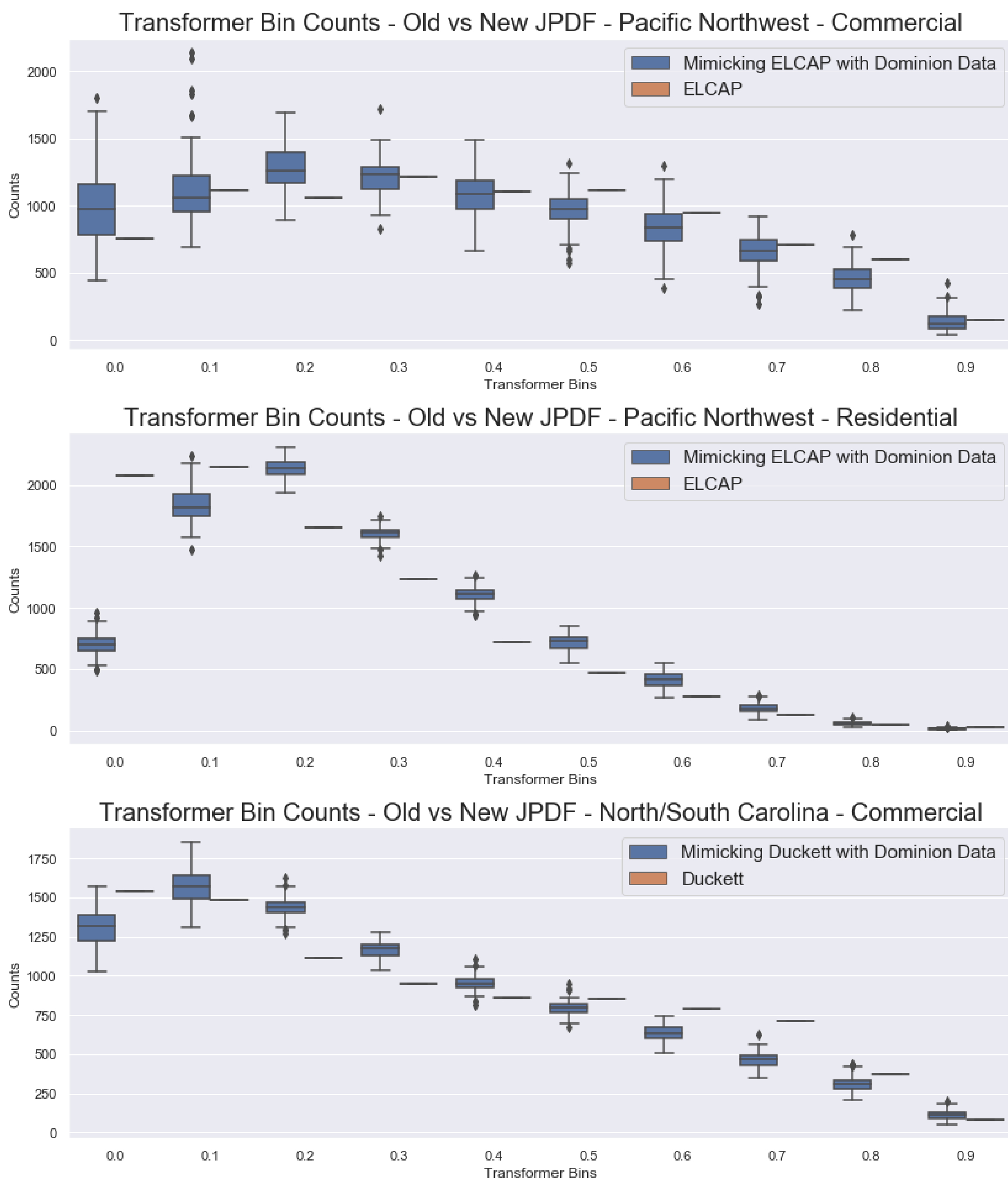


Figure 7D.4.1 Distributions of Transformer Loads generated for the Pacific Northwest, and North/South Carolina using the actual and copy JPDF

7D.5 FINDINGS

It was observed that the distribution of the commercial sector transformer loads obtained from the actual PNW and copy JPDFs were very similar. This was also the case with the actual NSC and copy JPDFs in the Carolinas. in the case of the Pacific Northwest region's residential transformers, the counts in the lower transformer bins were higher for the actual PNW JPDF, as compared to the copies. However, DOE estimated the impact of lower transformer values to be immaterial. Based on these observations, DOE concluded that there were no major differences between the JPDFs obtained from the data used for the previous rulemaking and the new datasets used in this rulemaking, in either region.

REFERENCES

1. United States Census Bureau. TIGER/Line Shapefiles. (2016). at <https://www2.census.gov/geo/tiger/TIGER2016/ZCTA5>

2. PJM . Hourly Load: Metered. at <https://dataminer2.pjm.com/feed/hrl_load_metered/definition>

3. Homeland Infrastructure Foundation-Level Data (HIFLD). Independent System Operators. at < https://hifld-geoplatform.opendata.arcgis.com/datasets/9d1099b016e5482c900d657f06f3ac80_0>

3. Homeland Infrastructure Foundation-Level Data (HIFLD). NERC Regions. at < https://hifld-geoplatform.opendata.arcgis.com/datasets/6b2af23c67f04f4cb01d88c61aaf558a_0>

4. PJM. Territory Served. at <https://www.pjm.com/-/media/about-pjm/pjm-zones.ashx?la=en>

APPENDIX 8A. UNCERTAINTY AND VARIABILITY

TABLE OF CONTENTS

LIST OF FIGURES

APPENDIX 8A. UNCERTAINTY AND VARIABILITY

8A.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.

8A.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.

8A.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).

8A.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.

8A.5 PROBABILITY ANALYSIS AND THE USE OF MONTE CARLO

To quantify the uncertainty and variability that exist in inputs to the engineering, LCC, and payback period analyses, DOE used software developed in the Python programming language, 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 model will reveal only a single outcome, generally the most likely or average outcome. Risk analysis uses both a model and simulation to automatically analyze the effect of varying inputs on outputs of the modeled system. One type of model 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.

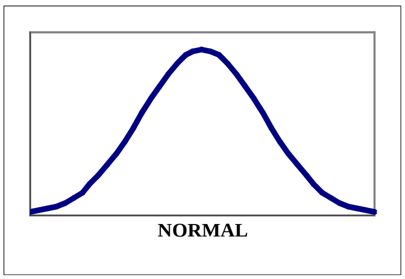


Figure 8A.1 Normal Probability Distribution

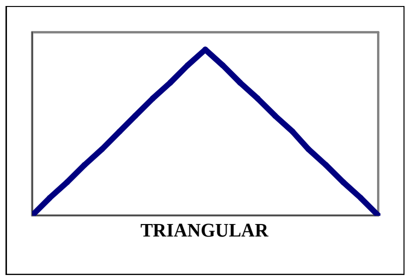


Figure 8A.2 Triangular Probability Distribution

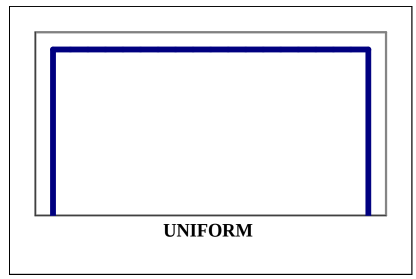


Figure 8A.3 Uniform Probability Distribution

During a simulation, multiple scenarios are calculated by sampling values repeatedly from the probability distributions for the uncertain variables. Monte Carlo simulations can consist of as many trials (or scenarios) as desired—hundreds or even thousands. During a single trial, the simulation randomly selects a value from the defined possibilities (the range and shape of the probability distribution) for each uncertain variable and then recalculates the results.

APPENDIX 8B. LIFE-CYCLE COST SENSITIVITY ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

APPENDIX 8B. LIFE-CYCLE COST SENSITIVITY ANALYSIS

8B.1 REPRESENTATIVE UNIT 1 RESULTS

8B.1.1 Representative Unit 1 Results, Reference Scenario

Table 8B.1.1 Results of Life-Cycle Cost Analysis: Representative Unit 1, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,532	76	1,568	4,100	-	32.0
1	2,602	74	1,524	4,126	34.8	32.0
2	2,626	73	1,505	4,131	36.6	32.0
3	2,794	69	1,412	4,206	37.0	32.0
4	2,929	54	1,159	4,088	18.4	32.0
5	3,580	41	868	4,448	30.3	32.0

Table 8B.1.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 1, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	63.0	-28
2	68.5	-32
3	79.3	-108
4	45.4	12
5	85.7	-350

8B.1.2 Representative Unit 1 Results, Low Electricity Price Scenario

Table 8B.1.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 1 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,532	75	1,513	4,045	-	32.0
1	2,602	73	1,471	4,072	35.0	32.0
2	2,626	73	1,453	4,079	36.6	32.0
3	2,794	68	1,362	4,156	37.1	32.0
4	2,929	54	1,118	4,047	18.5	32.0
5	3,580	41	838	4,418	30.5	32.0

Table 8B.1.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 1 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	63.8	-29
2	69.5	-35
3	80.5	-113
4	48.5	-2
5	87.5	-375

8B.1.3 Representative Unit 1 Results, High Electricity Price Scenario

Table 8B.1.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 1 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,532	76	1,611	4,143	-	32.0
1	2,602	74	1,565	4,167	34.7	32.0
2	2,626	73	1,546	4,173	36.5	32.0
3	2,794	69	1,450	4,244	36.9	32.0
4	2,929	54	1,191	4,120	18.3	32.0
5	3,580	41	892	4,472	30.2	32.0

Table 8B.1.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 1 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	62.2	-26
2	67.8	-30
3	78.5	-103
4	42.9	23
5	84.4	-331

8B.2 REPRESENTATIVE UNIT 2 RESULTS

8B.2.1 Representative Unit 2 Results, Reference Scenario

Table 8B.2.1 Results of Life-Cycle Cost Analysis: Representative Unit 2, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,498	43	891	2,389	-	32.0
1	1,545	43	876	2,421	117.1	32.0
2	1,578	40	830	2,408	24.9	32.0
3	1,651	32	689	2,339	14.0	32.0
4	1,735	29	626	2,361	17.4	32.0
5	2,110	24	489	2,599	31.4	32.0

Table 8B.2.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 2, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	62.6	-34
2	60.2	-20
3	36.9	51
4	41.4	29
5	84.0	-211

8B.2.2 Representative Unit 2 Results, Low Electricity Price Scenario

Table 8B.2.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 2 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,498	43	860	2,358	-	32.0
1	1,545	43	846	2,390	116.1	32.0
2	1,578	40	801	2,380	25.1	32.0
3	1,651	32	665	2,315	14.1	32.0
4	1,735	29	604	2,339	17.5	32.0
5	2,110	23	472	2,582	31.5	32.0

Table 8B.2.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 2 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	63.2	-35
2	61.1	-22
3	38.2	44
4	43.3	19
5	85.8	-225

8B.2.3 Representative Unit 2 Results, High Electricity Price Scenario

Table 8B.2.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 2 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,498	43	915	2,413	-	32.0
1	1,545	43	900	2,445	118.3	32.0
2	1,578	40	853	2,431	24.8	32.0
3	1,651	32	707	2,358	13.9	32.0
4	1,735	30	643	2,378	17.3	32.0
5	2,110	24	502	2,613	31.2	32.0

Table 8B.2.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 2 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	62.0	-34
2	59.4	-19
3	36.1	57
4	39.7	36
5	82.4	-200

8B.3 REPRESENTATIVE UNIT 3 RESULTS

8B.3.1 Representative Unit 3 Results, Reference Scenario

Table 8B.3.1 Results of Life-Cycle Cost Analysis: Representative Unit 3, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	9,565	456	9,501	19,066	-	32.0
1	9,825	440	9,263	19,088	16.0	32.0
2	10,010	425	9,020	19,029	14.6	32.0
3	10,494	385	8,279	18,773	13.1	32.0
4	11,257	341	7,312	18,569	14.7	32.0
5	13,598	269	5,653	19,251	21.6	32.0

Table 8B.3.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 3, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	34.2	-35
2	44.4	41
3	39.8	305
4	34.5	513
5	60.7	-188

8B.3.2 Representative Unit 3 Results, Low Electricity Price Scenario

Table 8B.3.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 3 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	9,565	454	9,169	18,734	-	32.0
1	9,825	438	8,940	18,765	16.2	32.0
2	10,010	424	8,704	18,713	14.7	32.0
3	10,494	383	7,988	18,482	13.1	32.0
4	11,257	340	7,055	18,312	14.8	32.0
5	13,598	268	5,455	19,053	21.7	32.0

Table 8B.3.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 3 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	34.4	-46
2	45.0	24
3	40.6	263
4	36.2	436
5	63.2	-324

8B.3.3 Representative Unit 3 Results, High Electricity Price Scenario

Table 8B.3.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 3 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	9,565	458	9,762	19,327	-	32.0
1	9,825	442	9,518	19,343	15.9	32.0
2	10,010	427	9,267	19,277	14.4	32.0
3	10,494	386	8,506	19,000	13.0	32.0
4	11,257	342	7,512	18,769	14.7	32.0
5	13,598	270	5,808	19,406	21.5	32.0

Table 8B.3.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 3 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	34.0	-24
2	44.0	56
3	39.2	341
4	33.2	576
5	58.2	-80

8B.4 REPRESENTATIVE UNIT 4 RESULTS

8B.4.1 Representative Unit 4 Results, Reference Scenario

Table 8B.4.1 Results of Life-Cycle Cost Analysis: Representative Unit 4, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	**First Year's Operating Cost**	**Lifetime Operating Cost**	**LCC**		
0	6,615	217	4,456	11,070	-	32.0
1	6,807	185	3,851	10,658	6.1	32.0
2	6,876	160	3,381	10,257	4.6	32.0
3	6,882	157	3,331	10,213	4.5	32.0
4	6,880	155	3,279	10,159	4.3	32.0
5	7,492	133	2,766	10,258	10.4	32.0

Table 8B.4.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 4, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	31.1	484
2	6.8	906
3	4.3	954
4	2.0	1,014
5	13.7	838

8B.4.2 Representative Unit 4 Results, Low Electricity Price Scenario

Table 8B.4.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 4 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	6,615	216	4,302	10,917	-	32.0
1	6,807	185	3,718	10,525	6.1	32.0
2	6,876	160	3,264	10,140	4.6	32.0
3	6,882	157	3,215	10,098	4.5	32.0
4	6,880	155	3,165	10,046	4.3	32.0
5	7,492	132	2,670	10,163	10.5	32.0

Table 8B.4.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 4 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	31.8	460
2	6.9	865
3	4.4	912
4	2.0	970
5	14.3	778

8B.4.3 Representative Unit 4 Results, High Electricity Price Scenario

Table 8B.4.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 4 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	6,615	218	4,577	11,192	-	32.0
1	6,807	186	3,956	10,763	6.0	32.0
2	6,876	161	3,473	10,349	4.6	32.0
3	6,882	158	3,421	10,304	4.5	32.0
4	6,880	156	3,368	10,249	4.3	32.0
5	7,492	133	2,841	10,334	10.4	32.0

Table 8B.4.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 4 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	30.8	504
2	6.6	939
3	4.2	989
4	2.0	1,051
5	13.3	885

8B.5 REPRESENTATIVE UNIT 5 RESULTS

8B.5.1 Representative Unit 5 Results, Reference Scenario

Table 8B.5.1 Results of Life-Cycle Cost Analysis: Representative Unit 5, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	29,374	1,393	29,655	59,029	-	31.9
1	29,840	1,363	28,965	58,805	15.7	31.9
2	30,207	1,342	28,848	59,055	16.2	31.9
3	31,237	1,292	27,823	59,060	18.5	31.9
4	33,007	1,177	25,178	58,186	16.8	31.9
5	45,081	881	18,476	63,557	30.7	31.9

Table 8B.5.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 5, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	21.9	481
2	38.9	-33
3	52.0	-32
4	47.8	856
5	77.9	-4,569

8B.5.2 Representative Unit 5 Results, Low Electricity Price Scenario

Table 8B.5.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 5 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	29,374	1,389	28,633	58,006	-	31.9
1	29,840	1,359	27,967	57,807	15.8	31.9
2	30,207	1,338	27,853	58,060	16.4	31.9
3	31,237	1,288	26,862	58,100	18.6	31.9
4	33,007	1,173	24,310	57,317	16.9	31.9
5	45,081	878	17,840	62,922	30.8	31.9

Table 8B.5.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 5 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	22.2	429
2	39.5	-66
3	52.8	-96
4	48.9	700
5	79.2	-4,959

8B.5.3 Representative Unit 5 Results, High Electricity Price Scenario

Table 8B.5.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 5 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	29,374	1,398	30,466	59,840	-	31.9
1	29,840	1,368	29,758	59,598	15.7	31.9
2	30,207	1,346	29,637	59,844	16.1	31.9
3	31,237	1,297	28,584	59,821	18.4	31.9
4	33,007	1,181	25,867	58,874	16.7	31.9
5	45,081	884	18,982	64,063	30.6	31.9

Table 8B.5.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 5 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	21.7	521
2	38.4	-5
3	51.4	20
4	47.1	981
5	76.5	-4,261

8B.6 REPRESENTATIVE UNIT 6 RESULTS

8B.6.1 Representative Unit 6 Results, Reference Scenario

Table 8B.6.1 Results of Life-Cycle Cost Analysis: Representative Unit 6, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,138	94	1,236	2,374	-	32.2
1	1,140	88	1,154	2,294	0.3	32.2
2	1,176	81	1,057	2,234	2.8	32.2
3	1,235	76	992	2,227	5.2	32.2
4	1,430	70	919	2,349	12.1	32.2
5	1,633	44	582	2,216	9.9	32.2

Table 8B.6.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 6, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	1.2	266
2	11.2	202
3	26.7	154
4	54.2	25
5	36.2	159

8B.6.2 Representative Unit 6 Results, Low Electricity Price Scenario

Table 8B.6.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 6 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,138	93	1,192	2,330	-	32.2
1	1,140	87	1,113	2,253	0.3	32.2
2	1,176	80	1,020	2,196	2.8	32.2
3	1,235	75	957	2,192	5.3	32.2
4	1,430	69	886	2,316	12.2	32.2
5	1,633	44	562	2,195	10.1	32.2

Table 8B.6.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 6 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	1.2	256
2	11.5	193
3	27.5	145
4	56.0	14
5	38.9	135

8B.6.3 Representative Unit 6 Results, High Electricity Price Scenario

Table 8B.6.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 6 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	1,138	96	1,273	2,411	-	32.2
1	1,140	89	1,188	2,329	0.3	32.2
2	1,176	82	1,089	2,265	2.7	32.2
3	1,235	77	1,022	2,257	5.2	32.2
4	1,430	71	947	2,376	11.9	32.2
5	1,633	45	600	2,233	9.8	32.2

Table 8B.6.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 6 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	1.2	274
2	10.9	210
3	25.9	162
4	53.0	35
5	34.1	178

8B.7 REPRESENTATIVE UNIT 7 RESULTS

8B.7.1 Representative Unit 7 Results, Reference Scenario

Table 8B.7.1 Results of Life-Cycle Cost Analysis: Representative Unit 7, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,625	204	2,648	5,273	-	31.9
1	2,652	201	2,607	5,259	8.5	31.9
2	2,682	198	2,571	5,254	9.6	31.9
3	3,296	161	2,085	5,381	15.5	31.9
4	3,425	133	1,728	5,153	11.3	31.9
5	3,591	118	1,528	5,119	11.2	31.9

Table 8B.7.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 7, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	9.8	61
2	27.1	32
3	66.1	-108
4	42.0	120
5	41.8	154

8B.7.2 Representative Unit 7 Results, Low Electricity Price Scenario

Table 8B.7.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 7 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,625	201	2,553	5,179	-	31.9
1	2,652	198	2,514	5,166	8.6	31.9
2	2,682	195	2,480	5,162	9.7	31.9
3	3,296	158	2,011	5,307	15.7	31.9
4	3,425	131	1,666	5,091	11.4	31.9
5	3,591	116	1,473	5,065	11.4	31.9

Table 8B.7.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 7 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	10.0	54
2	27.5	27
3	68.2	-128
4	45.3	88
5	45.5	114

8B.7.3 Representative Unit 7 Results, High Electricity Price Scenario

Table 8B.7.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 7 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	2,625	207	2,727	5,353	-	31.9
1	2,652	204	2,686	5,337	8.4	31.9
2	2,682	201	2,649	5,331	9.4	31.9
3	3,296	163	2,148	5,444	15.2	31.9
4	3,425	135	1,780	5,205	11.1	31.9
5	3,591	119	1,574	5,165	11.0	31.9

Table 8B.7.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 7 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	9.7	66
2	26.9	36
3	64.2	-91
4	39.0	148
5	38.8	187

8B.8 REPRESENTATIVE UNIT 8 RESULTS

8B.8.1 Representative Unit 8 Results, Reference Scenario

Table 8B.8.1 Results of Life-Cycle Cost Analysis: Representative Unit 8, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	7,029	620	8,031	15,059	-	32.0
1	7,044	602	7,801	14,846	0.9	32.0
2	7,365	579	7,501	14,866	8.3	32.0
3	9,102	497	6,438	15,540	16.9	32.0
4	9,957	364	4,721	14,678	11.5	32.0
5	9,956	363	4,707	14,663	11.4	32.0

Table 8B.8.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 8, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	6.5	425
2	31.4	204
3	78.2	-480
4	40.5	381
5	39.9	397

8B.8.2 Representative Unit 8 Results, Low Electricity Price Scenario

Table 8B.8.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 8 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	7,029	612	7,740	14,769	-	32.0
1	7,044	594	7,519	14,564	0.9	32.0
2	7,365	571	7,230	14,595	8.4	32.0
3	9,102	490	6,205	15,307	17.1	32.0
4	9,957	360	4,550	14,508	11.6	32.0
5	9,956	358	4,536	14,492	11.6	32.0

Table 8B.8.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 8 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	6.7	408
2	32.6	184
3	80.6	-538
4	44.8	261
5	44.3	277

8B.8.3 Representative Unit 8 Results, High Electricity Price Scenario

Table 8B.8.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 8 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	7,029	629	8,273	15,302	-	32.0
1	7,044	611	8,037	15,081	0.9	32.0
2	7,365	587	7,728	15,093	8.2	32.0
3	9,102	504	6,632	15,734	16.6	32.0
4	9,957	370	4,864	14,821	11.3	32.0
5	9,956	369	4,849	14,805	11.3	32.0

Table 8B.8.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 8 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	6.3	439
2	30.5	221
3	76.0	-432
4	37.1	481
5	36.5	497

8B.9 REPRESENTATIVE UNIT 9 RESULTS

8B.9.1 Representative Unit 9 Results, Reference Scenario

Table 8B.9.1 Results of Life-Cycle Cost Analysis: Representative Unit 9, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	11,870	873	11,356	23,226	-	32.1
1	11,917	861	11,207	23,124	4.2	32.1
2	12,015	836	10,881	22,896	4.0	32.1
3	13,207	695	9,043	22,250	7.5	32.1
4	13,756	623	8,101	21,857	7.5	32.1
5	15,092	547	7,123	22,215	9.9	32.1

Table 8B.9.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 9, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	2.4	603
2	8.6	582
3	23.8	976
4	10.6	1,369
5	31.9	1,011

8B.9.2 Representative Unit 9 Results, Low Electricity Price Scenario

Table 8B.9.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 9 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	11,870	861	10,944	22,814	-	32.1
1	11,917	850	10,801	22,718	4.3	32.1
2	12,015	825	10,486	22,502	4.0	32.1
3	13,207	686	8,715	21,922	7.6	32.1
4	13,756	615	7,807	21,563	7.6	32.1
5	15,092	540	6,865	21,957	10.0	32.1

Table 8B.9.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 9 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	2.5	571
2	9.0	552
3	24.8	892
4	11.9	1,251
5	34.9	858

8B.9.3 Representative Unit 9 Results, High Electricity Price Scenario

Table 8B.9.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 9 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	11,870	885	11,700	23,570	-	32.1
1	11,917	874	11,547	23,464	4.1	32.1
2	12,015	848	11,210	23,225	3.9	32.1
3	13,207	705	9,317	22,524	7.4	32.1
4	13,756	632	8,346	22,102	7.4	32.1
5	15,092	555	7,338	22,430	9.8	32.1

Table 8B.9.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 9 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	2.4	630
2	8.4	607
3	23.1	1,046
4	9.7	1,467
5	29.5	1,139

8B.10 REPRESENTATIVE UNIT 10 RESULTS

8B.10.1 Representative Unit 10 Results, Reference Scenario

Table 8B.10.1 Results of Life-Cycle Cost Analysis: Representative Unit 10, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	36,234	2,537	32,782	69,017	-	31.9
1	37,655	2,446	31,619	69,274	15.7	31.9
2	39,746	2,372	30,666	70,411	21.4	31.9
3	45,538	1,866	24,121	69,659	13.9	31.9
4	48,446	1,764	22,803	71,248	15.8	31.9
5	55,282	1,591	20,576	75,858	20.1	31.9

Table 8B.10.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 10, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	44.7	-344
2	75.1	-1,395
3	63.0	-642
4	75.0	-2,232
5	89.0	-6,841

8B.10.2 Representative Unit 10 Results, Low Electricity Price Scenario

Table 8B.10.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 10 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	36,234	2,503	31,595	67,830	-	31.9
1	37,655	2,414	30,474	68,129	15.9	31.9
2	39,746	2,341	29,555	69,301	21.6	31.9
3	45,538	1,841	23,248	68,786	14.1	31.9
4	48,446	1,741	21,977	70,423	16.0	31.9
5	55,282	1,570	19,831	75,113	20.4	31.9

Table 8B.10.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 10 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	45.5	-401
2	76.5	-1,472
3	66.8	-956
4	78.4	-2,593
5	90.7	-7,284

8B.10.3 Representative Unit 10 Results, High Electricity Price Scenario

Table 8B.10.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 10 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	36,234	2,574	33,773	70,007	-	31.9
1	37,655	2,482	32,575	70,230	15.4	31.9
2	39,746	2,407	31,592	71,338	21.0	31.9
3	45,538	1,893	24,850	70,388	13.7	31.9
4	48,446	1,790	23,491	71,937	15.6	31.9
5	55,282	1,614	21,197	76,479	19.9	31.9

Table 8B.10.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 10 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	44.1	-297
2	73.9	-1,331
3	59.6	-380
4	72.4	-1,930
5	87.4	-6,472

8B.11 REPRESENTATIVE UNIT 11 RESULTS

8B.11.1 Representative Unit 11 Results, Reference Scenario

Table 8B.11.1 Results of Life-Cycle Cost Analysis: Representative Unit 11, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	16,794	1,080	14,000	30,795	-	32.0
1	17,496	1,053	13,656	31,152	26.3	32.0
2	18,412	1,004	13,016	31,428	21.3	32.0
3	20,619	790	10,241	30,860	13.2	32.0
4	20,971	744	9,651	30,622	12.4	32.0
5	22,859	665	8,619	31,478	14.6	32.0

Table 8B.11.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 11, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	56.9	-444
2	74.6	-633
3	55.5	-65
4	50.9	173
5	69.6	-683

8B.11.2 Representative Unit 11 Results, Low Electricity Price Scenario

Table 8B.11.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 11 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	16,794	1,066	13,496	30,290	-	32.0
1	17,496	1,039	13,164	30,660	26.7	32.0
2	18,412	991	12,547	30,959	21.6	32.0
3	20,619	780	9,872	30,491	13.4	32.0
4	20,971	734	9,303	30,274	12.6	32.0
5	22,859	656	8,309	31,168	14.8	32.0

Table 8B.11.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 11 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	57.8	-459
2	76.2	-668
3	59.5	-201
4	55.3	16
5	73.0	-878

8B.11.3 Representative Unit 11 Results, High Electricity Price Scenario

Table 8B.11.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 11 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	16,794	1,095	14,423	31,217	-	32.0
1	17,496	1,068	14,067	31,564	26.0	32.0
2	18,412	1,018	13,408	31,820	21.0	32.0
3	20,619	802	10,549	31,169	13.0	32.0
4	20,971	755	9,942	30,913	12.3	32.0
5	22,859	674	8,879	31,738	14.4	32.0

Table 8B.11.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 11 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	56.3	-431
2	73.2	-603
3	52.0	48
4	47.3	304
5	66.3	-521

8B.12 REPRESENTATIVE UNIT 12 RESULTS

8B.12.1 Representative Unit 12 Results, Reference Scenario

Table 8B.12.1 Results of Life-Cycle Cost Analysis: Representative Unit 12, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	43,121	3,010	38,955	82,076	-	32.0
1	45,941	2,892	37,441	83,382	24.0	32.0
2	47,757	2,807	36,329	84,087	22.8	32.0
3	60,232	2,191	28,358	88,590	20.9	32.0
4	61,831	2,108	27,294	89,125	20.8	32.0
5	69,419	1,904	24,646	94,065	23.8	32.0

Table 8B.12.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 12, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	76.6	-1,368
2	83.5	-2,010
3	95.0	-6,513
4	94.8	-7,048
5	96.4	-11,988

8B.12.2 Representative Unit 12 Results, Low Electricity Price Scenario

Table 8B.12.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 12 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	43,121	2,970	37,541	80,662	-	32.0
1	45,941	2,854	36,082	82,023	24.4	32.0
2	47,757	2,770	35,011	82,769	23.1	32.0
3	60,232	2,162	27,328	87,560	21.2	32.0
4	61,831	2,081	26,303	88,134	21.0	32.0
5	69,419	1,879	23,752	93,171	24.1	32.0

Table 8B.12.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 12 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	77.6	-1,426
2	84.8	-2,106
3	96.1	-6,897
4	95.8	-7,471
5	97.1	-12,508

8B.12.3 Representative Unit 12 Results, High Electricity Price Scenario

Table 8B.12.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 12 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	43,121	3,054	40,134	83,256	-	32.0
1	45,941	2,935	38,575	84,516	23.7	32.0
2	47,757	2,848	37,429	85,186	22.5	32.0
3	60,232	2,223	29,216	89,448	20.6	32.0
4	61,831	2,139	28,120	89,951	20.5	32.0
5	69,419	1,932	25,392	94,810	23.4	32.0

Table 8B.12.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 12 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	75.5	-1,320
2	82.2	-1,931
3	93.9	-6,193
4	93.6	-6,695
5	95.7	-11,555

8B.13 REPRESENTATIVE UNIT 13 RESULTS

8B.13.1 Representative Unit 13 Results, Reference Scenario

Table 8B.13.1 Results of Life-Cycle Cost Analysis: Representative Unit 13, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	21,065	1,200	15,640	36,705	-	32.0
1	21,542	1,159	15,115	36,657	11.8	32.0
2	22,127	1,117	14,562	36,689	12.8	32.0
3	25,705	954	12,439	38,144	18.9	32.0
4	28,031	834	10,872	38,903	19.1	32.0
5	28,535	789	10,290	38,825	18.2	32.0

Table 8B.13.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 13, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	42.8	57
2	53.8	16
3	81.8	-1,439
4	89.9	-2,198
5	87.3	-2,119

8B.13.2 Representative Unit 13 Results, Low Electricity Price Scenario

Table 8B.13.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 13 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	21,065	1,184	15,074	36,140	-	32.0
1	21,542	1,144	14,569	36,111	11.9	32.0
2	22,127	1,102	14,035	36,163	13.0	32.0
3	25,705	942	11,989	37,694	19.1	32.0
4	28,031	823	10,479	38,510	19.3	32.0
5	28,535	779	9,917	38,453	18.4	32.0

Table 8B.13.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 13 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	43.6	34
2	55.1	-23
3	83.7	-1,555
4	91.6	-2,370
5	89.5	-2,313

8B.13.3 Representative Unit 13 Results, High Electricity Price Scenario

Table 8B.13.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 13 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	21,065	1,217	16,113	37,178	-	32.0
1	21,542	1,176	15,572	37,114	11.6	32.0
2	22,127	1,133	15,002	37,129	12.6	32.0
3	25,705	968	12,815	38,520	18.6	32.0
4	28,031	846	11,201	39,232	18.8	32.0
5	28,535	801	10,601	39,136	17.9	32.0

Table 8B.13.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 13 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	42.3	75
2	52.9	49
3	80.2	-1,342
4	88.0	-2,054
5	85.4	-1,958

8B.14 REPRESENTATIVE UNIT 14 RESULTS

8B.14.1 Representative Unit 14 Results, Reference Scenario

Table 8B.14.1 Results of Life-Cycle Cost Analysis: Representative Unit 14, Reference Scenario

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	56,418	4,178	54,371	110,789	-	32.0
1	59,677	4,026	52,395	112,072	21.4	32.0
2	61,885	3,915	50,956	112,841	20.8	32.0
3	77,514	3,068	39,934	117,448	19.0	32.0
4	80,487	2,900	37,759	118,246	18.8	32.0
5	88,608	2,670	34,759	123,367	21.3	32.0

Table 8B.14.2 Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution: Representative Unit 14, Reference Scenario

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	81.3	-1,283
2	77.3	-2,052
3	88.1	-6,659
4	90.7	-7,457
5	96.1	-12,578

8B.14.2 Representative Unit 14 Results, Low Electricity Price Scenario

Table 8B.14.3 Effects of Low Electricity Price on Life-Cycle Cost Analysis for Representative Unit 14 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	56,418	4,123	52,394	108,812	-	32.0
1	59,677	3,973	50,490	110,166	21.7	32.0
2	61,885	3,864	49,103	110,988	21.1	32.0
3	77,514	3,027	38,481	115,994	19.2	32.0
4	80,487	2,862	36,385	116,872	19.1	32.0
5	88,608	2,635	33,495	122,103	21.6	32.0

Table 8B.14.4 Effects of Low Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 14 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	83.2	-1,355
2	78.7	-2,177
3	90.3	-7,183
4	92.6	-8,060
5	97.1	-13,291

8B.14.3 Representative Unit 14 Results, High Electricity Price Scenario

Table 8B.14.5 Effects of High Electricity Price on Life-Cycle Cost Analysis for Representative Unit 14 (2020$)

Standard Level	Average Costs (2020$)				Simple Payback Period (years)	Average Lifetime (years)
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	56,418	4,240	56,020	112,438	-	32.0
1	59,677	4,085	53,984	113,660	21.1	32.0
2	61,885	3,973	52,500	114,386	20.5	32.0
3	77,514	3,113	41,146	118,659	18.7	32.0
4	80,487	2,943	38,904	119,391	18.6	32.0
5	88,608	2,709	35,813	124,421	21.0	32.0

Table 8B.14.6 Effects of High Electricity Price on Life-Cycle Cost Savings Relative to Base Case Efficiency Distribution for Representative Unit 14 (2020$)

Standard Level	% Consumers with Net Cost	Average Savings - Impacted Consumers (2020)$
1	80.0	-1,223
2	76.2	-1,948
3	86.3	-6,221
4	88.8	-6,953
5	95.1	-11,983

IMPACT ON STRUCTURES CAUSED FROM INCREASED TRANSFORMER SIZE

for

Lawrence Berkeley National Laboratory

on behalf of the

U.S. Department of Energy

September 7, 2020

Prepared By

Ted Dimberio, P.E.
President
Line Design University

Table of Contents

Table of Tables

Table of Figures

PURPOSE OF TRANSFORMER STRUCTURAL LOADING ANALYSIS

Installing a new transformer or replacing an existing transformer with larger dimensions is a common occurrence performed daily by all electric distribution utilities. [1] The National Electrical Safety Code (NESC) requires a structure to comply with strength and clearance requirements each time conductors, transformers, equipment, telecommunication facilities and foreign installations such as banners time domestic and foreign facilities are added to a structure as stated in NESC Rule 013. Although an engineering analysis to determine NESC compliance is preferred, it is common practice to determine if a new or larger transformer will meet NESC compliance by making visual observations by non-licensed employees.

The purpose of this study is to attempt to quantify the amount of distribution transformer weight, or volume, can be increased under a variety of conditions before the attached pole needs to be upgraded to maintain Allowable Wind Spans. This study will analyze the impact allowable wind span has on a combination of phases, aluminum conductor steel-reinforced cable (ACSR) conductors, transformers, and telecommunication sizes for a variety of NESC combined ice and wind loading, NESC extreme wind loading, and California General Order 95 (GO 95) loading zone conditions.

This study will also analyze the impact how new or larger transformers will have on vertical loads on deadend structures having short guy leads and NESC requirements based on vertical clearance to the bottom of transformer cases, separation between telecommunication and electric objects, along span clearance between electric to electric and telecommunication to electric conductors, pole strength based on Allowable Wind Span, and along span vertical ground clearance to electric and telecommunication conductors.

[1] Larger in this context also refers to transformers of greater weight.

POLE HEAD CONFIGURATIONS

Electric distribution utilities use a variety of pole top assemblies based on the conditions of their service territory which include, and not limited to, tree clearance conditions, horizontal clearance to obstacles such as buildings along streets and alleys, lightning conditions within their service territory, minimize electric outages and controlling aeolian vibration. Pole head configurations consist of the pole top assemblies and the position of existing and future telecommunication attachments on structures. Six of the most common poles to configurations for electric distribution utilities includes:

- Common neutral assemblies with neutral located below the phase conductors
- Narrow profile assemblies which result in shorter spans and reduced right-of-way width
- Double circuit assemblies to eliminate parallel distribution lines along roadways
- Spacer cable assemblies which utilize covered conductors and reduced separation between conductors to reduce right-of-way width and does not disturb electric service during momentary contact with tree limbs
- High neutral assemblies which provides shielding in areas with increased lightning frequency
- No common neutral assemblies

The common neutral assemblies with the neutral located below the phase conductors is most widely used in the electric distribution industry and will be used to perform structural load calculations in this study.

Electric distribution utilities standardize the location of their pole mounted distribution transformers. This study will assume the top of pole mounted transformers will be at the same level as the common neutral location. The length of transformers will impact the location of telecommunication attachments and must be considered when installing new or larger transformers. The addition of new or larger transformer on existing structures are allowable as long as the resulting structure complies with the NESC Edition of the time the structure was originally installed.

Appendix E identifies typical tangent and deadend pole head configurations used in this study.

DESIGN GUIDELINES

The designs of overhead distribution power lines are based on ice and wind load calculations for the area in which facilities are located. It is common practice to develop design guidelines to simplify the design process and eliminate the need to perform complex line design calculations. The design guidelines for this study are limited to the NESC combined ice and wind loadings, NESC extreme wind loading and GO 95. The two main design guidelines to determine if transformers can be installed on distribution power poles include:

Allowable Wind Span – A single wood distribution pole must be able to withstand loads equivalent to all the expected applied loads without exceeding the permitted load of the distribution pole.

Shortest Guy Lead to Support Vertical Loads on Deadend Structures – Single wood distribution poles must be able to sustain loads due to the vertical weight of the transformers, conductors, and the vertical component of the load supported by the guys.

NESC Figure 250-1 identifies a general loading map of the United States used in the design of overhead distribution power lines.

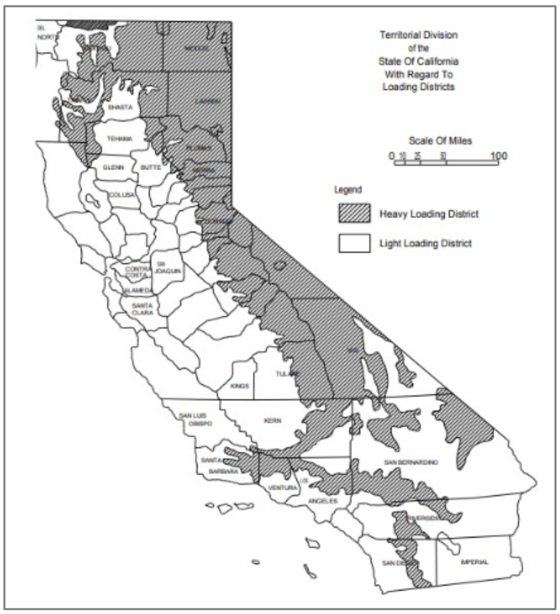
Figure 1   NESC Figure 250-1 Loading Map

NESC Table 250-1 illustrates the radial thickness of ice, horizontal wind pressure and temperature used in the calculating the loads for the three loading districts identified in NESC Figure 250-1.

NESC Figure 250-2 includes several maps that illustrate the extreme winds in portions of the United States which are used to calculate wind loads.

GO 95 separates California into Light and Heavy Loading Districts based on elevation that is below or exceeds 3,000’ above sea level. Figure 2 identifies the locations of the Light and Heavy Loading Districts. The Light Loading District includes areas with ground elevations below 3,000’, and the Heavy Loading District includes areas with ground elevations exceeding 3,000. Table 7 identifies selected GO 95 loading criteria for the Light and Heavy Loading Districts.

Figure 2 GO-95 Loading Districts



Combined Ice and Wind

Design guidelines showing the Allowable Wind Span for selected pole top assemblies are often used in distribution line design projects. However, it is difficult to develop guidelines involving additional underbuild conductors and different types of equipment on structures. In these cases it is necessary to perform pole loading calculations to determine the Allowable Wind Span for selected pole classes. The following factors are included in typical pole loading calculations:

- Pole moment based on the horizontal wind pressure for the given NESC loading district
- Pole resisting moment based on the selected pole species
- Wind on all conductors based on the transverse wind load factor identified in NESC Table 253-1 and the wind pressure for the given NESC loading district
- Wind load on the equipment attached to the structure

Pole Resisting Moment

The pole resisting moment is required to determine the proper pole class to support the loads imposed on structures. Factors that impact the pole resisting moment include the wood species, ground line circumference and NESC grade of construction. Appendix E identifies pole circumference values for typical pole species:

The pole circumference is determined 6-feet from the pole butt as identified in Appendix E. When a pole is not installed at the 6-foot setting depth, the ground line circumference has to be calculated by using the following formula:

$$Ground\ Line\ Circumference, C_G = \frac{(L_P - L_G) \times (C_B - C_T)}{(L_P - L_B)} + C_T$$

The pole resisting moment is a function of the ground line circumference, pole fiber stress and strength factor. Appendix B identifies the fiber stress for typical pole species:

The pole resisting moment can be determined from the following formula:

$$Resisting\ Moment, M_R = F_S \times F_B \times 0.000264 \times C_G^3$$

The Pole Resisting Moment at the ground line is relatively close between the various pole species even with the wide range of fiber stress and ground line circumference. The following table identifies the Resisting Moment for a 40-foot Class 6 pole and Grade C Construction:

Table 1 Pole Resisting Moment by Pole Species

Pole Species	Pole Resisting Moment (Ft-Lbs)
Alaska Yellow Cedar	40,499
Douglas Fir	41,557
Jack Pine/Northern White Pine	42,021
Lodgepole Pine	42,021
Northern White Cedar	41,878
Ponderosa Pine	42,083
Red Pine	42,021
Southern Pine	41,557
Western Larch	41,379
Western Red Cedar	42,083

Loading on Equipment (Transformers)

Equipment mounted on a pole needs to be included in the pole loading calculation to determine proper pole strength. Factors included in the pole loading calculation pertaining to equipment include the:

- equipment shape,
- equipment width,
- equipment height,
- equipment weight,
- distance from ground line where equipment is mounted, and
- distance from the center of pole to center of equipment

Transformer dimensions should be as accurate as possible, and it may be necessary to obtain accurate dimensions from manufacturer product specifications. Appendix C identifies examples of transformer dimensions for a variety of transformer sizes.

The moment caused from the wind on transformers is a function of wind pressure, shape of equipment, and equipment width and height, and can be determined from the following formula:

$$M_{WE} = \frac{No.\times F_W \times H_E \times W_F \times S_F \times E_W \times E_H}{144}$$

Where the Shape Factor, S_F, is a dimensionless number that characterizes the efficiency of the shape, regardless of its scale, for a given mode of loading. Shape Factor is a value that is affected by an object's shape but is independent of its dimensions. It is the perimeter of the contour around the area of the transformer divided by the square root of the area. Therefore, the Shape Factor for a rectangular transformer is 1.6 and for a cylindrical transformer is 1.0. The Shape Factor can be obtained from the Appendix B:

The moment caused from transformer weight is a function of transformer height attachment above ground line, transformer weight and distance from the center of pole to center of the transformer. The moment of transformer weight can be determined from the following formula:

$$M_{EW} = \frac{No.\times F_V \times E_W \times X}{12}$$

Moment on Pole

The moment on the pole includes the transverse winds induced on the pole with no attached equipment or conductors. Factors that need to be considered to determine pole moment include:

- Grade of construction

- Horizontal wind pressure (see Table 7 for W_F values)
- Height of pole above ground
- Pole top circumference
- Pole ground line circumference

The following formula used to determine pole moment:

$$Moment\ on\ Pole, M_P = F_W \times W_F \times H_P^2 \times \left(\frac{(2 \times C_T) + C_G}{72 \times \pi}\right)$$

Moment on Conductors

The moment on conductors includes the horizontal wind load induced on primary, neutral and underbuild conductors for the selected NESC loading district. Wind pressure should be increased based on past experience and wind loads in the utility geographic service territory. Factors that impact the moment on conductors include:

- Conductor diameter
- Radial thickness of ice
- Wind pressure
- Height of conductor above ground
- Grade of construction

It is often necessary to convert wind speed (mph) to wind pressure (lbs/ft^2). This can be accomplished using the following formula:

$$W_F = 0.0025 \times V_W^2$$

The transverse wind load includes the radial thickness of ice and the wind pressure on the overhead distribution conductors for the structure wind span. The ice and wind load is based on the selected NESC loading district. The transverse wind load can be determined from the following formula:

$$Transverse\ Wind\ Load, W_H = \frac{(D + 2 \times I_R)\ \times W_F}{12}$$

The moment on conductors is a function of the height of each conductor and the transverse wind load factor based on the grade of construction. The wind on conductors can be determined from the following formula:

$$Wind\ on\ Conductors, M_C = F_W \times (W_{CA} \times H_{CA} + W_{CB} \times H_{CB} + W_{CC} \times H_{CC} + W_{CN} \times H_{CN})$$

Allowable Wind Span

The pole resisting moment must have sufficient strength to withstand the wind on the pole, wind on the conductors, and the wind and weight on mounted equipment for the given wind span. Therefore, the *Allowable Wind Span* has to be greater than the one-half the sum of the two adjacent spans.

The *Maximum Allowable Wind Span* for structures without attached equipment is determined by:

$$Maximum\ Wind\ Span, S_M = \frac{Resisting\ Moment - Moment\ on\ Pole}{Wind\ on\ Conductors} = \frac{M_R - M_P}{M_C}$$

The *Maximum Allowable Wind Span* for structures with mounted equipment can be determined by the following formula:

$$S_M = \frac{Resisting\ Moment - Moment\ on\ Pole - Moment\ of\ Equipment\ Weight - Moment\ of\ Wind\ on\ Equpment}{Wind\ on\ Conductors}$$

which can be expressed as:

$$S_M = \frac{M_R - M_P - M_{EW} - M_{WE}}{M_C}$$

Extreme Wind

NESC Rule 261A2e requires structures less than 60 feet above ground to be designed to withstand the extreme wind load in Rule 250C applied in any direction on the structure without conductors, and any supported facilities and equipment which may be in place prior to installation of conductors. The application of extreme wind in this study is similar to combined ice and wind, except for the moment on the pole. The load in pounds is expressed as:

$$Load\ in\ pounds = 0.00256 \times {V_W}^2 \times k_z \times G_{RF} \times I \times C_f \times A_1$$

Where:

k_z = 1.0 for pole height greater than 33 feet to 50 feet above ground (see Appendix B)

I = the Importance Factor and is 1.0 for utility structures (see Appendix C)

C_f = the Shape Factor (see Appendix B)

The Gust Response Factor, G_{RF}, is a measure of the effective wind loading on a structure and is intended to translate the dynamic response phenomena due to gust loading into relatively simpler static design criteria. The Gust Response Factor is identified in Appendix B and can also be calculated as follow:

$$G_{RF} = \frac{[1 + (2.7 \times E_S \times B_S^{0.5})]}{k_v^2}$$

where E_S is the Structure Exposure Factor, which is the potential percentage of loss to a specific asset if a specific threat is realized, and B_S is the quasi-static wind load on the structure, and is expressed as:

$$E_S = 0.346 \times \left[\frac{33}{(0.67 \times h)}\right]^{\frac{1}{7}}$$

$$B_S = \frac{1}{\left[1 + \frac{(0.67 \times h)}{220}\right]}$$

The moment on the pole for extreme wind is then expressed as:

$$Moment\ on\ Pole, M_P = 0.00256 \times {V_W}^2 \times k_z \times G_{RF} \times I \times C_f \ \times \ H_P^2 \times \left(\frac{(2 \times C_T) + C_G}{72 \times \pi}\right)$$

Where I is the Importance Factor, and can be found in Table 8

The Maximum Allowable Wind Span for structures with pole mounted equipment can be determined by the following formula:

$$S_M = \frac{M_R - M_P - M_{EW} - M_{WE}}{M_C}$$

General Order 95

The GO 95 calculations used to develop Allowable Wind Span and Shortest Guy Lead to Support Vertical Load on Deadend Structures are the same as NESC Combined Ice and Wind except for selected load factors which are identified in Appendix B.

Shortest Guy Lead to Support Vertical Loads on Deadend Structures

A guyed pole acts as a column sustaining axial loads which include the vertical weight on the conductors, vertical weight on the equipment and the vertical component of the load supported by the shortest guy lead. A pole acting as a column becomes unstable when the axial force becomes large enough to cause large lateral deflections. These deflections will add to the moment loads from the loaded conductors and equipment installed on the pole.

The Critical Axial Load, P_{CR}, is the moment at which the axial load is greater than what the column member is capable of supporting. The load at which buckling occurs is called the critical load. The Critical Axial Load for a pole acting as a column is identified in the following formula:

$$P_{CR} = \frac{\pi \times E \times A^2}{F_{V1} \times K_A \times (K_U \times H_{GB})^2}$$

Where A is the cross-section area of the pole located 2/3rds the distance from the ground line to the lowest guy attachment:

$$A = \frac{1}{4\pi} \times \left(\frac{(C_B - C_T) \times (H_P - 0.667 \times H_{GB})}{L_P - L_B} + C_T \right)^2$$

The Vertical Component of the Load, G_V, contributed from the guy wire is determined from the following equation:

$$G_V = \frac{(S_H) \times (M_C) + M_T + M_P + M_{EW}}{L_{G1}}$$

The Vertical Load of Conductors, W_C, is the product of the weight span of the two adjacent spans and total loaded vertical weight of all of the conductors.

$$W_C = (S_V) \times (\Sigma W_V)$$

Pole class is adequate if the Critical Axial Load, P_{CR}, is greater or equal to the sum of the vertical component of the load contributed from the guy wire and the vertical load of conductors.

$$(G_V + W_C) \leq P_{CR}$$

The above equation can be rewritten as follows:

$$G_V \leq P_{CR} - W_C$$

The formula for G_V can then be substituted into the above equation.

$$\frac{(S_H) \times (M_C) + M_T + M_P + M_E}{L_{G1}} \leq P_{CR} - W_C$$

The Shortest Guy Lead, L_G, to sustain the vertical load can then be determined by the following equation.

$$L_{G1} \geq \frac{(S_H) \times (M_C) + M_T + M_P + M_E}{P_{CR} - W_C}$$

In most cases, axial loading will not be a problem if a 1:1 guy lead, or the distance from the pole ground line to the guy attachment is equal to the distance from the pole ground line to the first anchor location, is installed. The axial load doubles each time the guy lead is reduced by one-half. Therefore, if the shortest guy lead is reduced by one-half, the axial load will double, and if the shortest guy lead is reduced one-fourth from the 1:1 guy lead, the axial load will increase by an approximate factor of four. In these cases, a larger pole class may be required to support the increased axial loading.

Typical Span Lengths Based on Utility Service Territory

There are several factors that determine typical span lengths for areas across a utility service territory that include basic pole length, pole top assembly selection, required vertical ground clearance, conductor size and type, and conductor tension. Utilities will typically begin an overhead distribution power line design based on a basic pole length for a geographic area, and then adjust pole lengths for selected poles based on the change in ground elevation.

Overhead power lines in urban areas experience approximately 35 consumers per mile, where utilities in rural areas experience approximately 5 consumers per mile. Property in urban areas are typically platted, so electric utilities will typically place power poles on every other lot line to avoid the need to obtain right-of-way easements from neighboring property owners when extending conductors into a premise. Span lengths are typically shorter in urban areas because of consumer density. Power poles are also often taller in urban areas because the utilities need to consider additional pole length to accommodate safety space for multiple telecommunication attachments. Span lengths in urban areas with 50' lot lines will typically have 100' span lengths and 150' span lengths in platted areas with 75' lot lines.

A common method to determine typical and most economical span lengths is based on the level ground span. The level ground span is the maximum span for the selected conductor size and type, conductor tension, required NESC vertical ground clearance plus any construction tolerance, selected pole top assembly and pole length. The NESC vertical ground clearance is defined in NESC Rule 232A which includes the worst case condition between 120^{o}F final sag, maximum conductor temperature if greater than 120^{o}F, and 32^{o}F final sag with the radial thickness of ice as identified in NESC Table 230-1. The level ground span will identify typical span lengths to provide adequate vertical ground clearance and adequate horizontal and vertical clearance between the conductors as required by NESC Rule 235. The level ground span will theoretically be different for each conductor selection.

Electric utilities in rural areas have approximately 5 consumers per mile and very few platted areas along their main overhead distribution power lines. Utilities in rural areas will determine their span lengths based on an economic analysis and span length limitations based on NESC clearance between conductors and vertical ground clearance to the phase and neutral conductors under loaded final sag conditions. Utilities in the Heavy Loading District will have span lengths shorter than the Light Loading District due to ice loading on the conductors. Utilities in the NESC Heavy, Medium, and Light Loading Districts will design span lengths in the ranges of 250’ to 275’, 275’ to 325’, and 325’ to 375’.

NESC FACTORS TO CONSIDER WHEN INSTALLING LARGER TRANSFORMERS

Several factors need to be considered when replacing a transformer with either larger dimensions of the same kilovolt-ampere (kVA) or larger kVA. Making a visual observation to install a larger transformer is an unsafe engineering procedure and especially difficult without thorough knowledge of the NESC.

Any *Make Ready* work which includes installing a larger pole or having the telecommunication company relocate telecom attachment locations to obtain sufficient safety space must be completed before installing a new or larger transformer. Each of these considerations are shown in Figure 3, and discussed in the following sections.

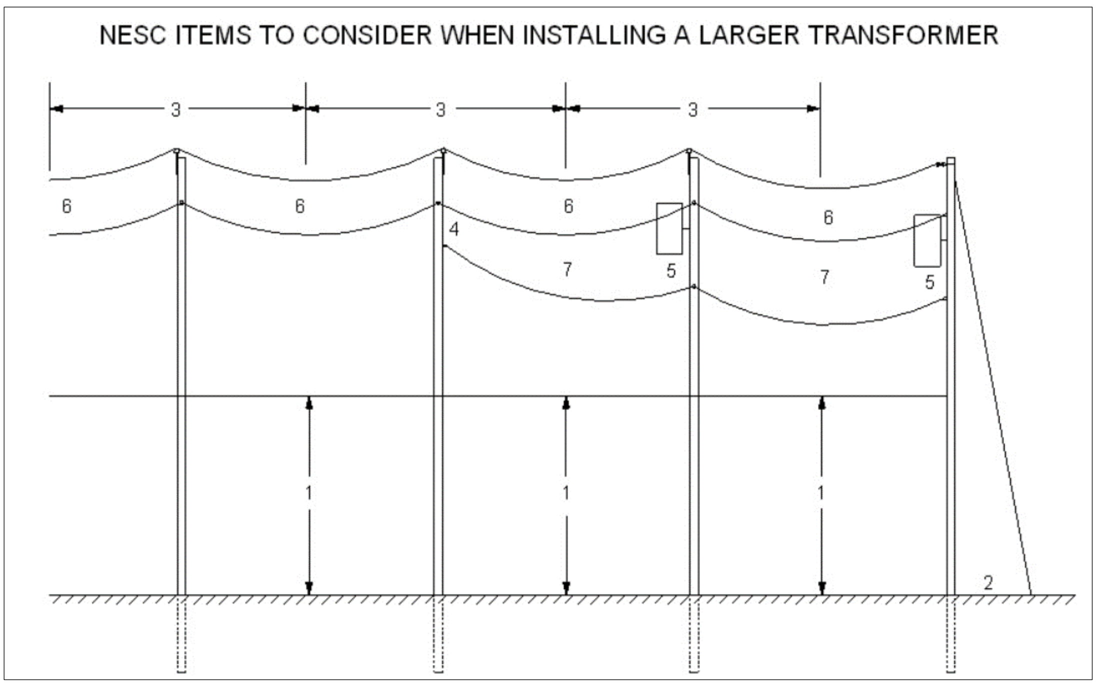


Figure 3 NESC Items to Consider when Installing a Larger Transformer

Vertical Ground Clearance (1)

NESC Rule 232 requires vertical clearances of wires, conductors, cables and equipment above ground, roadway, rail and water surfaces to meet the clearances identified in NESC Table 232-1 based on the final sag for the following conditions:

- 120^{o}F, no wind displacement,
- The maximum conductor temperature for which the line is designed to operate if greater than 120^{o}F, no wind displacement, or
- 32^{o}F, no wind displacement, with radial thickness of ice, if any, specified in NESC Table 230-1 for the applicable zone

An accurate telecommunication sag and tension chart is required to determine if the telecommunication vertical ground clearance can be maintained if a transformer having greater length is installed.

Minimum Guy Lead to Prevent Pole Buckling (2)

The increased transformer weight for an existing pole class, along with the position of the shortest guy lead, will increase the axial load and may cause the structure to become unstable and cause lateral deflections. This scenario should be analyzed when installing a larger kVA transformer or converting from a single to three-phase transformer bank.

Allowable Wind Span to Comply with Pole Strength Requirements (3)

Increased transverse wind load on larger transformers and additional transformers will reduce the Allowable Wind Span and may not comply with NESC pole strength requirements. A visual observation to determine pole strength based on increased transformer size is very difficult.

Required Clearance Between Electric Object and Telecommunication Attachment (4)

NESC Rule 235-5 requires a minimum clearance between the neutral spool and telecommunication attachment on the structure. This rule could be violated if a transformer was installed on the structure and the telecommunication company did not relocate their attachment location to comply with NESC clearance rules.

Minimum Clearance Between Bottom of Effective Grounded Cases and Telecommunication Attachment (5)

NESC Table 238-1 requires a 30-inch clearance between communication conductors and supply equipment. This requirement can be violated if the length of a newly installed transformer is longer than the length of the existing transformer and the existing telecommunication cable attachment is not adjusted to the required location.

Along Span Clearance Between Electric Conductors (6) & (7)

NESC Rule 235C requires the along span clearance between conductors to be 75 percent of the required minimum clearance at the structure. Accurate sag and tension charts for the upper and lower conductors are required to calculate the maximum span length based on the separation between conductors at each adjacent structure. The clearance between conductors is based on the greater sag difference for the following two conditions:

- NESC Rule 235C2b(1)(c)i The upper conductor is at final sag at 120^{o}F or the maximum operating temperature for which the line is designed to operate, and the lower conductor is at final sag without electrical loading at the same ambient conditions that are used to determine the operating temperature of the upper conductor.
- NESC Rule 235C2b(1)(c)ii The upper conductor is at final sag at 32^{o}F with the radial thickness of ice, if any, specified in NESC Table 230-1 for the district concerned. The lower conductor is at final sag without electrical loading and without ice loading at the same ambient conditions as the upper conductor.

The NESC requires a structure to be in compliance after alterations are performed on the structure. It is difficult to comply with this requirement without accurate sag and tension charts and without performing required calculations to determine NESC compliance after a new or larger transformer is mounted on a structure.

Pole Strength Based on Age and Deterioration

Utilities replace poles for several reasons which include, and not limited to, aging, upgrades, road widening, cars hitting poles and storm damage. However, utilities have a desire to delay pole replacement due to age in order to maximize their capital expenditure and extending the life of poles which prolongs the need to replace poles. Utilities need to consider several factors when evaluating the types of pole wood preservatives (creosote, penta and chromated copper arsenate) to purchase, and ground line and pole top maintenance programs to extend life of poles. The environment to which poles are exposed to the climate has a major effect on pole life. Figure 4 identifies the level of deterioration in different parts of the country with Zone 1 having the lowest risk and Zone 5 having the highest risk of deterioration.

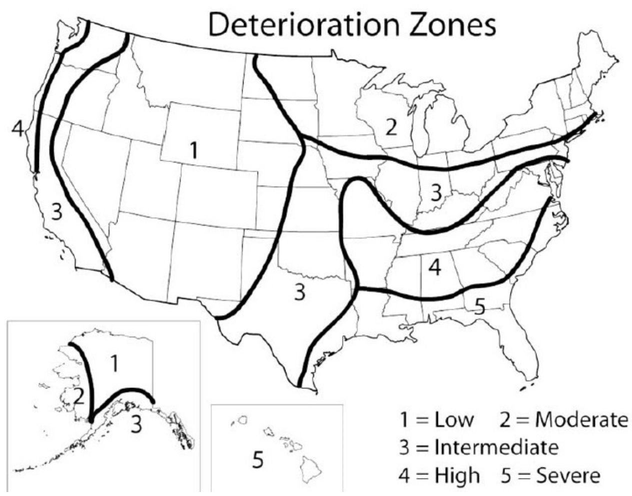


Figure 4 Deterioration Zone Map

Ground line treatment is also a major factor in extending the life of poles. Studies have indicated the average life of a pole is 45-years without performing a quality ground line treatment program. This includes a range of 40-years in the higher deterioration zones and 57-years in the lower deterioration zones. An effective ground line treatment program will extend the pole life from 16 to 28-years.

Most utilities inspect their poles on a 10-year cycle by boring into the pole at or below ground line and removing the decayed material by excavating around the pole and measuring the effective pole circumference. NESC Table 261-1, Footnotes 2 & 3 and GO 95 have provisions to reduce the required pole strength factor to replace or rehabilitate wood poles (see Table 10 – Wood Pole Strength Reduction Factors). A ground line treatment program will determine the amount of effective ground line pole circumference is available to sustain the transverse loads on the structure and overhead conductors.

As utilities perform effective ground line treatment programs to extend pole life, the deterioration of the pole top also needs to be considered when evaluating pole safety. Pole tops typically begin to decay after 25-years of service and the best form of maintenance is visual observation. Based on a January 2018 research paper titled "Pole Top Deterioration Study For The Electrical Utility Industry", pole inspection programs identified 15% to 50% of pole rejects were caused from pole top deterioration. Pole top deterioration typically includes pole top decay, decay at bolt connections, pole top splitting and excessive weathering.

The NESC also requires utility crews to visually inspect the pole for safety before ascending as described as follows:

NESC 422B Checking structures before climbing

1. *Before climbing poles, ladders, scaffolds, or other elevated structures, employees shall determine, to the extent practical, that the structures are capable of sustaining the additional or unbalanced stresses to which they will be subjected.*

2. *Where there are indications that poles and structures may be unsafe for climbing, they shall not be climbed until made safe by guying, bracing, or other means.*

Typical Transformer Installation Scenarios

There are several factors to consider when installing a transformer to a structure without an existing transformer or replacing a transformer of equal or larger size. The utility worker has to determine if the structure has deteriorated to a point where the structure needs to be replaced, the structure is of sufficient size to meet NESC strength requirements for the resultant structure, and if the resultant structure meets the NESC vertical ground clearance, clearance between electric conductors and clearance to telecommunication conductor requirements.

The pole should be replaced with a larger pole, if required, before installing a larger transformer. The utility should also wait for the telecommunication company to complete any

Make Ready work to obtain sufficient safety space between the electric and telecommunication facilities before installing a larger transformer.[2]

Pole strength requirements are achieved if the structure's Allowable Wind Span is greater than the Actual Wind Span. The Allowable Wind Span based on NESC combined ice and wind loading is derived from the following formula:

$$S_M = \frac{M_R - M_P - M_{EW} - M_{WE}}{M_C}$$

where the Moment due to Transformer Weight, M_{EW}, is:

$$M_{EW} = \frac{No. \times F_V \times E_W \times X}{12}$$

The component, E_W, represents the transformer weight in pounds (lbs.). As the transformer weight increases, the Allowable Wind Span will decrease.

The following examples illustrate how the material included in this study can be used to determine if the existing structure is sufficient for the utility crew to install a new or replace an existing transformer on a structure based on the following scenarios:

- Installing a new transformer to a structure having no telecommunication conductors
- Installing a new transformer to a structure having attached telecommunication conductors
- Replacing an existing transformer having the same kVA size and dimensions

[2] "Make ready" work is the process of ensuring the utility poles, upon which the fiber-optic cable will be strung, are in suitable condition to receive the cable.

- Replacing an existing transformer having the same kVA size, height and width, and increased weight

EXAMPLE LOOKUPS

Because Table 1 "Pole Resisting Moment by Pole Species" identifies pole strength is relatively similar for all pole species, the following examples assume a Southern Pine pole species having a fiber stress of 8,000 lbs/in^2. Distribution power poles are identified as 40-4 indicates a 40-foot, (ANSI) Class 4 pole. Neutral conductors are assumed to be full size or same size and type as the phase conductors.

Installing a New Transformer to a Structure Having No Telecommunication Conductors

Example 1: A utility will be installing a bank of three 1∅ - 25 kVA transformers in the Medium Loading District on a 40-5 structure having back and forward spans of 285' and 295' and supporting 4 – 1/O ACSR (6/1) conductors and meeting Grade C requirements.

Grade C	No Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,652	1,366	1,114	892	700	535	395
3∅ 1/O ACSR (6/1)	1,418	1,173	956	766	601	***459***	339
3∅ 4/O ACSR (6/1)	1,216	1,006	820	657	515	394	291
3∅ 336.4 ACSR (18/1)	1,101	911	742	595	466	356	263
3∅ 477.0 ACSR (18/1)	1,000	827	674	540	423	324	239

(Delete above chart) Solution: Refer to Appendix G

Based on the table, the Allowable Wind Span of 459' is greater than Actual Wind Span of 290'; therefore a 40-5 pole is adequate to support three 1∅ - 25 kVA transformers.

Example 2: A utility will be installing a bank of one 1∅ - 167 kVA transformer in the California Light Loading Zone on a 40-5 structure having back and forward spans of 310' and 330' and supporting 4 – 477.0 ACSR (18/1) conductors and meeting Grade B requirements.

Solution: Refer to Appendix H

Grade B 1∅ 1-167 kVA	No Telecommunications H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	5,641	4,602	3,685	2,885	2,193	1,602	1,105
1∅ 1/O ACSR (6/1)	3,643	2,971	2,380	1,863	1,416	1,035	713
1∅ 4/O ACSR (6/1)	2,575	2,101	1,682	1,317	1,001	731	504
1∅ 336.4 ACSR (18/1)	2,120	1,729	1,385	1,084	824	602	415
1∅ 477.0 ACSR (18/1)	1,781	1,453	1,164	911	693	506	349
3∅ 4 ACSR (7/1)	2,773	2,262	1,811	1,418	1,078	788	543
3∅ 1/O ACSR (6/1)	1,790	1,460	1,170	916	696	509	351
3∅ 4/O ACSR (6/1)	1,266	1,032	827	647	492	360	248
3∅ 336.4 ACSR (18/1)	1,042	850	681	533	405	296	204
3∅ 477.0 ACSR (18/1)	875	714	572	448	340	***249***	171

(Delete above chart)Based on the table, the Allowable Wind Span of 249' is less than Actual Wind Span of 320'; therefore the 40-5 pole will have to be replaced with a 40-4 pole to support one 1∅ - 167 kVA transformer.

Installing a New Transformer to a Structure Having Attached Telecommunication Conductors

Example 3: A utility will be installing three 1∅ - 167 kVA transformers in the Light Loading District on a 40-3 structure having back and forward spans of 200' and 220' and supporting 4 – 1/O ACSR (6/1) and 4" joint use telecommunication conductors and meeting Grade C requirements.

Grade C 3∅ 3-167 kVA	4" Telecommunications H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	504	395	299	215	142	80	28
3∅ 1/O ACSR (6/1)	440	345	261	***188***	124	70	24
3∅ 4/O ACSR (6/1)	384	301	228	164	108	61	21
3∅ 336.4 ACSR (18/1)	351	275	208	150	99	56	19
3∅ 477.0 ACSR (18/1)	321	252	191	137	91	51	18

Solution: Refer to Appendix G (Delete above chart)

Grade C							
	4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	483	387	302	213	149	94	47
3∅ 1/O ACSR (6/1)	433	347	271	***191***	134	84	42
3∅ 4/O ACSR (6/1)	387	310	241	170	119	75	38
3∅ 336.4 ACSR (18/1)	358	287	224	158	110	70	35
3∅ 477.0 ACSR (18/1)	332	266	207	146	102	65	33

Based on the table, the Allowable Wind Span of 188’ is less than Actual Wind Span of 210’; therefore a 40-2 pole is required to support three 1∅ - 167 kVA transformers.

Example 4: A utility will be installing a 1∅ - 25 kVA transformer in the California Heavy Loading Zone on a 40-1 structure having back and forward spans of 260’ and 260’ and supporting 4 – 1/O ACSR (6/1) and 2” joint use telecommunication conductors and meeting Grade B requirements.

Grade B							
	2" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	627	517	420	336	262	200	147
1∅ 1/O ACSR (6/1)	592	489	397	317	248	189	139
1∅ 4/O ACSR (6/1)	557	459	373	298	233	178	131
1∅ 336.4 ACSR (18/1)	533	440	357	285	223	170	125
1∅ 477.0 ACSR (18/1)	510	421	342	273	214	163	120
3∅ 4 ACSR (7/1)	408	337	274	219	171	130	96
3∅ 1/O ACSR (6/1)	379	***313***	254	203	159	121	89
3∅ 4/O ACSR (6/1)	350	289	235	187	147	112	82
3∅ 336.4 ACSR (18/1)	331	273	222	177	139	106	78
3∅ 477.0 ACSR (18/1)	313	258	210	168	131	100	74

Solution: Refer to Appendix H (Delete above chart)

Grade B 1∅ 1-25 kVA	2" Telecommunications H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	648	540	444	344	273	212	160
1∅ 1/O ACSR (6/1)	616	513	422	327	260	201	152
1∅ 4/O ACSR (6/1)	582	485	399	310	246	190	144
1∅ 336.4 ACSR (18/1)	560	467	384	298	236	183	138
1∅ 477.0 ACSR (18/1)	538	448	369	286	227	176	133
3∅ 4 ACSR (7/1)	439	366	301	233	185	143	108
3∅ 1/O ACSR (6/1)	409	341	***281***	218	173	134	101
3∅ 4/O ACSR (6/1)	380	317	261	202	160	124	94
3∅ 336.4 ACSR (18/1)	361	301	247	192	152	118	89
3∅ 477.0 ACSR (18/1)	342	285	235	182	144	112	84

Based on the table, the Allowable Wind Span of 313’ is greater than Actual Wind Span of 260’; therefore the 40-1 pole is adequate to support the 1∅ - 25 kVA transformer. Replacing an Existing Transformer Having the Same kVA Size and Dimensions

Replacing an Existing Transformer Having the Same kVA Size an Dimension

Example 5: A utility will be replacing one 1∅ - 500 kVA transformer in the Heavy Loading District on a 40-2 structure having back and forward spans of 285’ and 295’ and supporting 4 – 336.4 ACSR (18/1) and 4” joint use telecommunication conductors and meeting Grade B requirements.

Grade B 1∅ 1-500 kVA	4" Telecommunications H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	578	468	371	286	212	149	96
1∅ 1/O ACSR (6/1)	552	447	354	273	203	142	91
1∅ 4/O ACSR (6/1)	525	425	337	260	193	135	87
1∅ 336.4 ACSR (18/1)	506	410	325	251	186	131	84
1∅ 477.0 ACSR (18/1)	488	395	313	241	179	126	81
3∅ 4 ACSR (7/1)	404	327	259	200	148	104	67
3∅ 1/O ACSR (6/1)	379	307	243	187	139	98	63
3∅ 4/O ACSR (6/1)	353	286	227	175	130	91	58
3∅ 336.4 ACSR (18/1)	336	272	***216***	166	124	87	56
3∅ 477.0 ACSR (18/1)	320	259	205	158	118	83	53

Solution: Refer to Appendix G(Delete above chart)

Grade B		4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	551	453	365	274	208	152	104
1∅ 1/O ACSR (6/1)	531	436	352	264	201	146	100
1∅ 4/O ACSR (6/1)	509	418	338	253	193	140	96
1∅ 336.4 ACSR (18/1)	494	406	328	246	187	136	93
1∅ 477.0 ACSR (18/1)	479	394	318	238	181	132	90
3∅ 4 ACSR (7/1)	408	335	271	203	154	112	77
3∅ 1/O ACSR (6/1)	386	317	256	192	146	106	73
3∅ 4/O ACSR (6/1)	363	298	241	180	137	100	68
3∅ 336.4 ACSR (18/1)	348	286	***231***	173	132	96	65
3∅ 477.0 ACSR (18/1)	333	273	221	165	126	92	63

Based on the table, the Allowable Wind Span of ’216’ is less than Actual Wind Span of 290’; therefore a 40-H1 pole is required to support one 1∅ - 500 kVA transformer.

Example 6: A utility will be replacing three 1∅ - 500 kVA transformers in the California Light Loading Zone on a 40-3 structure having back and forward spans of 305’ and 325’ and supporting 4 – 4/O ACSR (6/1) and meeting Grade B requirements.

Grade B		No Telecommunications					
3∅ 3-500 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,791	1,280	830	437	97	-	-
3∅ 1/O ACSR (6/1)	1,157	827	536	282	62	-	-
3∅ 4/O ACSR (6/1)	818	584	379	***199***	44	-	-
3∅ 336.4 ACSR (18/1)	673	481	312	164	36	-	-
3∅ 477.0 ACSR (18/1)	566	404	262	138	30	-	-

Solution: Refer to Appendix H (Delete above chart)

Grade B	No Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,253	1,691	1,193	671	299	-	-
3∅ 1/O ACSR (6/1)	1,455	1,092	770	433	193	-	-
3∅ 4/O ACSR (6/1)	1,029	772	544	***306***	137	-	-
3∅ 336.4 ACSR (18/1)	847	635	448	252	113	-	-
3∅ 477.0 ACSR (18/1)	711	534	377	212	95	-	-

Based on the table, the Allowable Wind Span of 199' is less than Actual Wind Span of 315'; therefore a 40-2 pole is required to support the three 1∅ - 500 kVA transformers.

Replacing an Existing Transformer Having the Same kVA Size, Height and Width, and Increased Weight

Example 7: What is the difference in the Allowable Wind Span if one 1∅ - 167 kVA transformer weighing 1,490 lbs. installed on 40-3 structure with 4 – 4/O ACSR (6/1) and 2" joint use telecommunication conductors designed for Grade C construction and located in the Light Loading District with an Extreme Wind of 120 mph was replaced with one 1∅ - 167 kVA transformer weighing 1,788 lbs.

Allowable Wind Span							
1,490 Lbs (Average)							
Grade C	**2" Telecommunications**						
1∅ 1-167 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	1109	897	711	548	408	289	190
1∅ 1/O ACSR (6/1)	973	787	623	481	358	254	166
1∅ 4/O ACSR (6/1)	850	688	545	420	313	222	145
1∅ 336.4 ACSR (18/1)	779	630	499	385	287	203	133
1∅ 477.0 ACSR (18/1)	714	577	457	353	263	186	122
3∅ 4 ACSR (7/1)	877	709	562	434	323	229	150

3∅ 1/O ACSR (6/1)	716	579	458	354	263	187	122
3∅ 4/O ACSR (6/1)	589	476	377	***291***	217	154	101
3∅ 336.4 ACSR (18/1)	521	421	334	257	192	136	89
3∅ 477.0 ACSR (18/1)	464	375	297	229	171	121	79

Allowable Wind Span							
(1,788 Lbs - 20% Weight Increase)							
Grade C	**2" Telecommunications**						
1∅ 1-167 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	1099	887	701	538	398	279	180
1∅ 1/O ACSR (6/1)	964	778	615	472	349	245	158
1∅ 4/O ACSR (6/1)	843	680	537	413	305	214	138
1∅ 336.4 ACSR (18/1)	772	623	492	378	280	196	126
1∅ 477.0 ACSR (18/1)	707	571	451	346	256	180	116
3∅ 4 ACSR (7/1)	869	702	554	426	315	221	142
3∅ 1/O ACSR (6/1)	709	572	452	347	257	180	116
3∅ 4/O ACSR (6/1)	583	471	372	***286***	211	148	95
3∅ 336.4 ACSR (18/1)	516	417	329	253	187	131	84
3∅ 477.0 ACSR (18/1)	459	371	293	225	166	117	75

Allowable Wind Span Difference							
Grade C	**2" Telecommunications**						
1∅ 1-167 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	10	10	10	10	10	10	10
1∅ 1/O ACSR (6/1)	9	9	9	9	9	9	9
1∅ 4/O ACSR (6/1)	8	8	8	8	8	8	8
1∅ 336.4 ACSR (18/1)	7	7	7	7	7	7	7
1∅ 477.0 ACSR (18/1)	6	6	6	6	6	6	6
3∅ 4 ACSR (7/1)	8	8	8	8	8	8	8
3∅ 1/O ACSR (6/1)	6	6	6	6	6	6	6
3∅ 4/O ACSR (6/1)	5	5	5	***5***	5	5	5
3∅ 336.4 ACSR (18/1)	5	5	5	5	5	5	5
3∅ 477.0 ACSR (18/1)	4	4	4	4	4	4	4

Solution: Refer to Appendix G (Delete above chart)

Allowable Wind Span							
1,490 Lbs (Average)							
Grade C	**2" Telecommunications**						
1∅ 1-167 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	968	788	630	465	348	249	165
1∅ 1/O ACSR (6/1)	859	700	559	413	309	221	146
1∅ 4/O ACSR (6/1)	760	619	495	365	273	195	129
1∅ 336.4 ACSR (18/1)	700	571	456	336	252	180	119
1∅ 477.0 ACSR (18/1)	646	526	421	310	232	166	110
3∅ 4 ACSR (7/1)	782	637	509	376	282	201	133
3∅ 1/O ACSR (6/1)	648	528	422	311	233	167	110
3∅ 4/O ACSR (6/1)	540	440	352	***259***	194	139	92
3∅ 336.4 ACSR (18/1)	481	392	313	231	173	124	82
3∅ 477.0 ACSR (18/1)	431	351	280	207	155	111	73

Allowable Wind Span							
(1,788 Lbs - 20% Weight Increase)							
Grade C	**2" Telecommunications**						
1∅ 1-167 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	960	781	622	457	340	241	157
1∅ 1/O ACSR (6/1)	852	693	553	406	302	214	139
1∅ 4/O ACSR (6/1)	754	613	489	359	267	189	123
1∅ 336.4 ACSR (18/1)	695	565	450	331	246	174	114
1∅ 477.0 ACSR (18/1)	641	521	415	305	227	161	105
3∅ 4 ACSR (7/1)	776	631	503	370	275	195	127
3∅ 1/O ACSR (6/1)	643	523	417	306	228	161	105
3∅ 4/O ACSR (6/1)	536	436	347	***255***	190	134	88
3∅ 336.4 ACSR (18/1)	477	388	309	227	169	120	78
3∅ 477.0 ACSR (18/1)	427	347	277	203	151	107	70

Allowable Wind Span Difference							
Grade C	**2" Telecommunications**						
1∅ 1-167 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	8	8	8	8	8	8	8
1∅ 1/O ACSR (6/1)	7	7	7	7	7	7	7
1∅ 4/O ACSR (6/1)	6	6	6	6	6	6	6
1∅ 336.4 ACSR (18/1)	6	6	6	6	6	6	6
1∅ 477.0 ACSR (18/1)	5	5	5	5	5	5	5
3∅ 4 ACSR (7/1)	6	6	6	6	6	6	6
3∅ 1/O ACSR (6/1)	5	5	5	5	5	5	5
3∅ 4/O ACSR (6/1)	4	4	4	***4***	4	4	4
3∅ 336.4 ACSR (18/1)	4	4	4	4	4	4	4
3∅ 477.0 ACSR (18/1)	3	3	3	3	3	3	3

The difference in the Allowable Wind Span for one 1∅ - 167 kVA transformer weighing 1,490 lbs. replaced with the same kVA transformer weighing 1,788 lbs. decreased from 291’ to 286’.

Example 8: What is the difference in the Allowable Wind Span if three 1∅ - 25 kVA transformers weighing 468 lbs. installed on 40-2 structure with 4 – No. 4 ACSR (7/1) and 4” joint use telecommunication conductors designed for Grade B construction and located in the

California Heavy Loading Zone was replaced with three 1∅ - 25 kVA transformer weighing 562 lbs.

Allowable Wind Span							
468 Lbs (per Transformer)							
Grade B	**4" Telecommunications**						
3∅ 3-25 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	324	265	***212***	167	128	94	66
3∅ 1/O ACSR (6/1)	304	249	200	157	120	88	62
3∅ 4/O ACSR (6/1)	285	233	187	147	112	83	58
3∅ 336.4 ACSR (18/1)	272	222	178	140	107	79	55
3∅ 477.0 ACSR (18/1)	259	212	170	133	102	75	52

Allowable Wind Span							
(562 Lbs - 20% Weight Increase)							
Grade B	**4" Telecommunications**						
3∅ 3-25 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	322	263	***211***	165	126	92	64
3∅ 1/O ACSR (6/1)	303	247	198	155	118	87	60
3∅ 4/O ACSR (6/1)	283	231	185	145	110	81	56
3∅ 336.4 ACSR (18/1)	270	220	177	138	105	77	53
3∅ 477.0 ACSR (18/1)	257	210	168	132	100	74	51

Allowable Wind Span **Difference**							
Grade B	**4" Telecommunications**						
3∅ 3-25 kVA	**H1**	**1**	**2**	**3**	**4**	**5**	**6**
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	**2**	2	2	2	2
3∅ 1/O ACSR (6/1)	2	2	2	2	2	2	2
3∅ 4/O ACSR (6/1)	2	2	2	2	2	2	2

3∅ 336.4 ACSR (18/1)	2	2	2	2	2	2	2
3∅ 477.0 ACSR (18/1)	2	2	2	2	2	2	2

Solution: Refer to Appendix H (Delete above chart)

Allowable Wind Span							
468 Lbs (per Transformer)							
Grade B	4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	340	282	***230***	175	136	103	75
3∅ 1/O ACSR (6/1)	322	266	217	166	129	97	71
3∅ 4/O ACSR (6/1)	303	250	204	156	121	92	66
3∅ 336.4 ACSR (18/1)	290	240	196	149	116	88	64
3∅ 477.0 ACSR (18/1)	277	230	187	143	111	84	61

Allowable Wind Span							
(562 Lbs - 20% Weight Increase)							
Grade B	4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	339	280	***228***	173	135	101	73
3∅ 1/O ACSR (6/1)	320	265	215	164	127	96	69
3∅ 4/O ACSR (6/1)	301	249	203	154	120	90	65
3∅ 336.4 ACSR (18/1)	288	238	194	148	115	86	62
3∅ 477.0 ACSR (18/1)	276	228	186	141	110	83	59

Allowable Wind Span							
Difference							
Grade B	4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	**2**	2	2	2	2
3∅ 1/O ACSR (6/1)	2	2	2	2	2	2	2
3∅ 4/O ACSR (6/1)	2	2	2	2	2	2	2
3∅ 336.4 ACSR (18/1)	1	1	1	1	1	1	1
3∅ 477.0 ACSR (18/1)	1	1	1	1	1	1	1

The difference in the Allowable Wind Span for three 1∅ - 25 kVA transformers weighing 468 lbs. replaced with the same kVA transformer weighing 562 lbs. decreased insignificantly from 212’ to 211’.

Structure strength to support vertical axial loads

Example 9: Determine if a 40-4 deadend structure has sufficient strength to support 4 – 4/O ACSR (6/1) and 2” telecommunication conductors and three – 1-167 kVA transformers designed for Grade C requirements and located in the Medium Loading District. The deadend structure supports three downguys with 12’, 17’, and 22’ guy leads.

Grade C	2" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	7	12
3∅ 1/O ACSR (6/1)	1	2	2	3	5	8	14
3∅ 4/O ACSR (6/1)	1	2	3	4	***5***	9	18
3∅ 336.4 ACSR (18/1)	1	2	3	4	6	10	21
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	11	26

Solution: Refer to Appendix I

The shortest existing guy lead is 12’ which is longer than the allowable shortest guy lead of 5’ to support the three-phase deadend structure. Therefore, the 40-4 structure has sufficient strength.

Example 10: Determine if a 40-4 deadend structure has sufficient strength to support 4 – 4/O ACSR (6/1) and 4” telecommunication conductors and three – 1-167 kVA transformers designed for Grade B requirements and located in the California Heavy Loading Zone. The deadend structure supports three downguys with 12’, 17’, and 22’ guy leads.

Grade B	4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-

1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	3	4	6	10	20	-	-
3∅ 1/O ACSR (6/1)	3	5	7	11	23	-	-
3∅ 4/O ACSR (6/1)	4	5	8	13	***27***	-	-
3∅ 336.4 ACSR (18/1)	4	5	8	14	31	-	-
3∅ 477.0 ACSR (18/1)	4	6	9	15	-	-	-

Solution: Refer to Appendix I

The shortest existing guy lead is 12’ which is shorter than the allowable shortest guy lead of 27’ to support the three-phase deadend structure. Therefore, a 40-2 structure will be required to support the vertical axial load on the deadend structure.

APPENDIX A: SYMBOL MAP

Name	Symbol	Unit
Cross section of pole 2/3rds from ground line	A	Inches^2
Projected wind area	A_1	Feet^2
Quasi-static wind load on the structure	B_S	Constant
Pole circumference 6 feet from butt	C_B	Inches
Force coefficient (shape factor)	C_f	Constant
Pole circumference at ground line	C_G	Inches
Pole top circumference	C_T	Inches
Conductor diameter	D	Inches
Modulus of elasticity of wood	E	1,800,000 Lbs/In^2
Equipment height	E_H	Inches
Structure exposure factor	E_S	Constant
Equipment width	E_W	Inches
Equipment weight	E_{WT}	Lbs
Fiber stress	F_B	Lbs/In^2
Strength factor	F_S	Constant
Load factor for vertical load	F_V	Constant
Safety factor	F_{V1}	1.5 - Constant
Load factor for wind	F_W	Constant
Gust response factor	G_{RF}	Constant
Vertical component of load by guy wire	G_V	Lbs
Structure height above ground	h	Feet
Conductor height	H_C	Feet
Conductor height (A-phase)	H_{CA}	Feet
Conductor height (B-phase)	H_{CB}	Feet
Conductor height (C-phase)	H_{CC}	Feet
Conductor height (neutral)	H_{CN}	Feet
Height of equipment above ground	H_E	Feet
Height of bottom guy attachment above ground	H_{GB}	Feet
Pole height above ground	H_P	Feet
Importance factor	I	1.0
Radial thickness of ice	I_R	Inches
Conversion constant	K_A	576/Ft^2
Coefficient of unbraced length	K_U	0.7 (bisector guying)
Coefficient of unbraced length	K_U	2.0 (dead-end guying)
Velocity coefficient	k_V	1.43
Velocity pressure exposure coefficient	k_z	Constant
Bottom of pole to ANSI classification point	L_B	6 Feet
Guy lead length	L_{G1}	Feet
Pole buried depth	L_G	Feet

Pole length	L_P	Feet
Moment due to wind on each conductor	M_C	Ft-Lbs
Moment due to equipment weight	M_{EW}	Ft-Lbs
Moment due to wind on pole	M_P	Ft-Lbs
Pole Resisting Moment	M_R	Ft-Lbs
Moment due to conductor tension	M_T	Ft-Lbs
Moment due to wind on equipment	M_{WE}	Ft-Lbs
Critical buckling axial load	P_{CR}	Lbs
Span length – back span	S_1	Feet
Span length – forward span	S_2	Feet
Shape factor	S_F	Constant
One-half the sum of adjacent spans	S_H	Feet
Maximum allowable wind span	S_M	Feet
Distance between the low point of two sags	S_V	Feet
Wind span	S_W	Feet
Wind velocity	V_W	MPH
Vertical weight	W_C	Lbs/Ft
Vertical weight of conductor (A-phase)	W_{CA}	Lbs/Ft
Vertical weight of conductor (B-phase)	W_{CB}	Lbs/Ft
Vertical weight of conductor (C-phase)	W_{CC}	Lbs/Ft
Vertical weight of conductor (neutral)	W_{CN}	Lbs/Ft
Horizontal wind pressure	W_F	Lbs/Ft^2
Transverse wind load	W_H	Lbs/Ft
Loaded vertical weight of conductors	W_V	Lbs/Ft
Center of pole to center of equipment	X	Inches
Number of Transformers in the bank	No	Units

APPENDIX B. ASSUMPTIONS AND REFERENCES

Table 2 NESC Table 253-1 Load Factors

	Grade B	Grade C	
		At Crossings	Elsewhere
Vertical Loads (Weight) (F_V)	1.50	1.90	1.90
Transverse Loads (Wind) (F_G)	2.50	2.20	1.75

Table 3 NESC Table 261-1A Strength Factors (F_s)

	Grade B	Grade C
Wood Structures	0.65	0.85

Table 4 NESC Table 250-2 Velocity Pressure Exposure Coefficient (k_z)

Structure Height Above Ground (*h*) (ft)	k_z
≤ 33	0.9
> 33 to 50	1.0
> 50 to 80	1.1

Table 5 NESC Table 250-3 Gust Response Factor (G_{RF})

Structure Height Above Ground (*h*) (ft)	G_{RF}
≤ 33	1.02
> 33 to 50	0.97
>50 to 80	0.93

Table 6 Fiber Stress Ratings for Selected Pole Species

Pole Species	Fiber Stress (lbs/In^2)
Alaska Yellow Cedar	7,400
Douglas Fir	8,000
Jack Pine/Northern White Pine	6,600
Lodgepole Pine	6,600
Northern White Cedar	4,000
Ponderosa Pine	6,000
Red Pine	6,600

Southern Pine	8,000
Western Larch	8,400
Western Red Cedar	6,000

Table 7 Transformer Shape Factors (S_F)

Equipment Shape	S_F
Cylindrical Surface	1.0
Flat Surface	1.6

Table 8 Loading Criteria for Various Conditions

Loading Zone or District	Grade of Construction	Symbol				
		F_V	F_W (Conductors)	F_W (Wind)	I_R	W_F
NESC Light	B	1.50	2.50	2.50	0.00	9.00
	C	1.90	2.20	2.20	0.00	9.00
NESC Medium	B	1.50	2.50	2.50	0.25	4.00
	C	1.90	2.20	2.20	0.25	4.00
NESC Heavy	B	1.50	2.50	2.50	0.50	4.00
	C	1.90	2.20	2.20	0.50	4.00
GO 95 Light	A	1.50	2.00	4.00	0.00	8.00
	B	1.90	2.00	3.00	0.00	8.00
GO 95 Heavy	A	1.50	2.00	4.00	0.50	8.00
	B	1.90	2.00	3.00	0.50	8.00

Table 8 Importance Factor by Occupancy Category

Occupancy Category	Nature of Occupancy	Importance Factors		
	(for Buildings and Other Structures)	Wind, I_W	Snow, I_S	Earthquake, I_E
I	Low hazard to human life in event of failure	0.87	0.80	1.00
II	Those not listed in Occupancy Categories I, III or IV	1.00	1.00	1.00
III	Substantial hazard to human life in event of failure (Buildings greater than 300 occupants like Schools,	1.15	1.10	1.25

	Buildings with Public Assembly Areas)			
IV	Designated as an essential facility (Hospitals, Designated Emergency Shelters, Critical Defense Facilities)	1.15	1.20	1.50

Note: Occupancy Category and Importance Factor are parameters utilized in a building's structural design. Importance Factor is determined from Design Loads for Buildings and Other Structures (American Society of Civil Engineers ASCE 7) based on the Occupancy Category. The Importance Factor is a multiplier that increases or decreases the based design loads. The Occupancy Factor and Importance Factor are outlined by the International Building Code (IBC) and ASCE 7 as minimum required guidelines, with the primary intent of protecting the life and safety of the public.

APPENDIX D. TRANSFORMER DIMENSION EXAMPLES

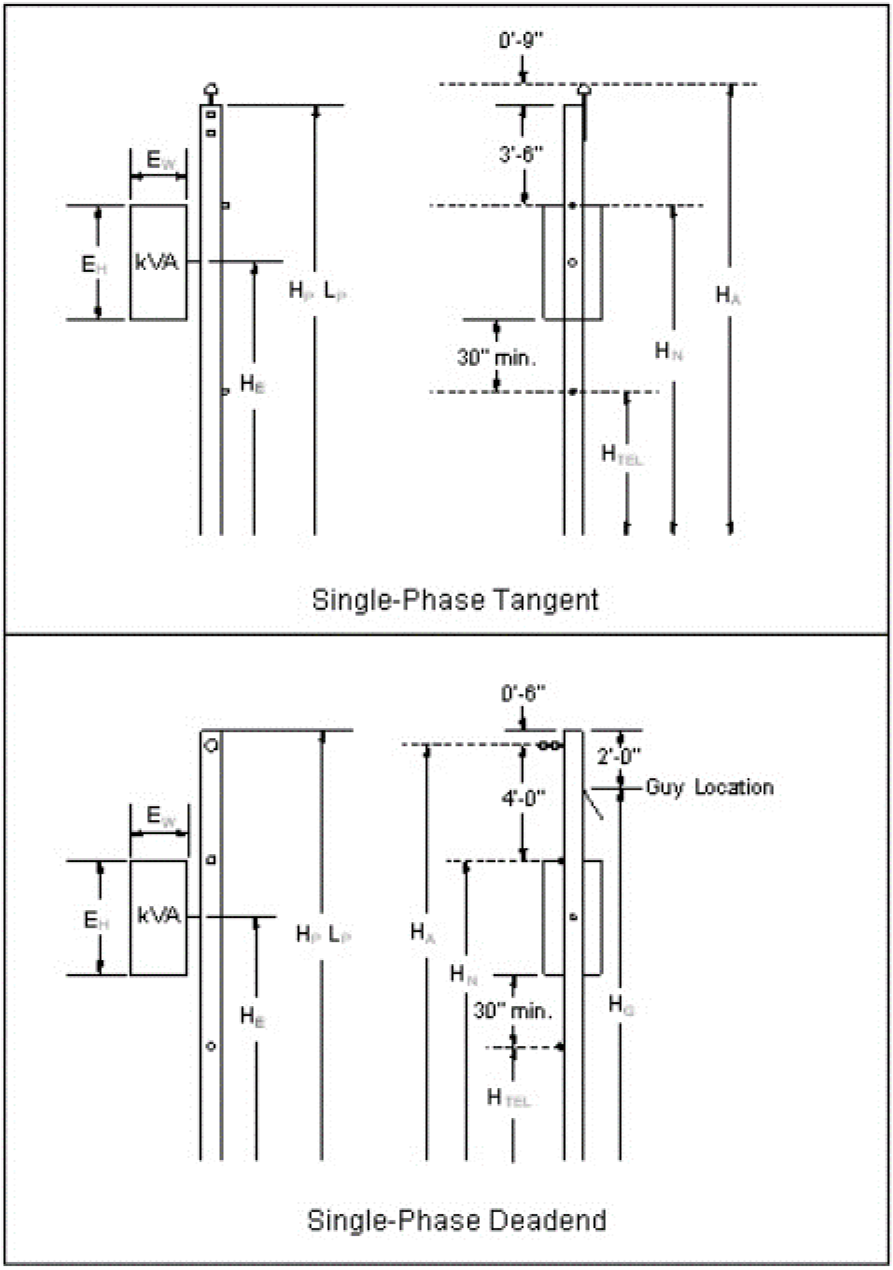
Table 9 Transformer Physical Characteristics Examples

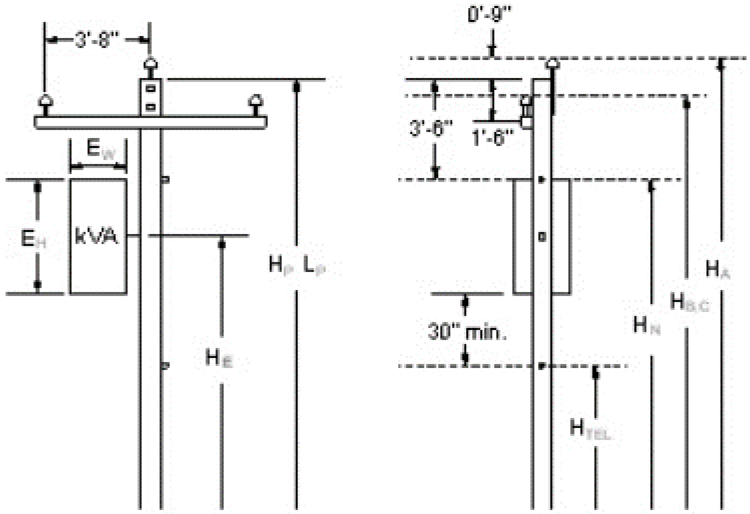
kVA Capacity	Length (Inches)	Width (Inches)	Weight (lbs)	Pole to Tank (Inches)
1∅ - 5 kVA	32.0	12.0	180	4.0
1∅ - 10 kVA	34.0	13.0	205	4.0
1∅ - 15 kVA	36.0	13.0	236	4.0
1∅ - 25 kVA	29.3	15.5	468	4.3
1∅ - 37.5 kVA	44.0	16.0	489	5.0
1∅ - 50 kVA	49.0	18.0	776	5.0
1∅ - 75 kVA	49.0	20.0	850	5.0
1∅ - 100 kVA	50.0	20.0	923	6.0
1∅ - 167 kVA	47.7	24.3	1,490	6.3
1∅ - 500 kVA	59.5	27.0	2,838	10.0
3∅ - 45 kVA	62.0	26.0	915	5.0
3∅ - 75 kVA	66.0	33.0	1,120	5.0
3∅ - 112.5 kVA	66.0	34.0	1,540	7.0
3∅ - 150 kVA	78.0	35.0	2,606	8.0
3∅ - 225 kVA	81.0	35.0	2,650	8.5
3∅ - 300 kVA	64.5	27.0	2,915	9.0
3∅ - 500 kVA	75.5	27.0	3,815	15.0

Table 10 Wood Pole Strength Reduction Factors

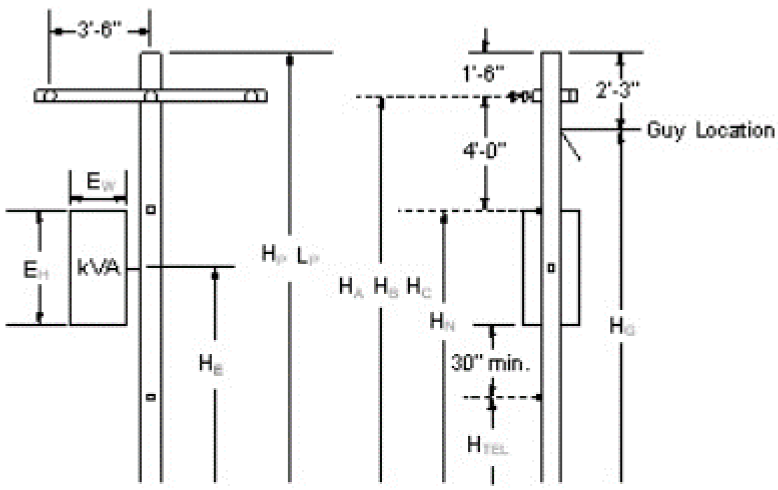
Loading	Grade of Construction		
	A	B	C
NESC Combined Ice and Wind	-	2/3	2/3
NESC Extreme Wind	-	3/4	3/4
GO 95	2/3	2/3	1/2

APPENDIX E. POLE HEAD CONFIGURATIONS





Three-Phase Tangent



Three-Phase Deadend

APPENDIX F. POLE CLASSIFICATION BY SPECIES

		Pole Class								
		H-2	H-1	1	2	3	4	5	6	7
		Pole Top Circumference (Inches)								
Pole Length	Pole Setting Depth	31	29	27	25	23	21	19	17	15
Northern White Cedar		Circumference 6-Feet from Pole Butt (Inches)								
20	4.00	-	-	38.0	35.5	33.0	30.5	28.0	26.0	24.0
25	5.00	-	-	42.0	39.5	36.5	34.0	31.5	29.0	27.0
30	5.50	-	-	45.5	43.0	40.0	37.0	34.5	32.0	29.5
35	6.00	-	-	49.0	46.0	42.5	39.5	37.0	34.0	31.5
40	6.00	-	-	51.5	48.5	45.0	42.0	39.0	36.0	-
45	6.50	-	-	54.5	51.0	47.5	44.0	41.0	-	-
50	7.00	-	-	57.0	53.5	49.5	46.0	43.0	-	-
55	7.50	-	-	59.0	55.5	51.5	48.0	-	-	-
60	8.00	-	-	61.0	57.5	53.5	50.0	-	-	-
Western Red Cedar, Ponderosa Pine										
20	4.00	-	-	33.5	31.5	29.5	27.0	25.0	23.0	21.5
25	5.00	-	-	37.0	34.5	32.5	30.0	28.0	25.5	24.0
30	5.50	-	-	40.0	37.5	35.0	32.5	30.0	28.0	26.0
35	6.00	48.0	45.5	42.5	40.0	37.5	34.5	32.0	30.0	27.5
40	6.00	51.0	48.0	45.0	42.5	39.5	36.5	34.0	31.5	-
45	6.50	53.5	50.5	47.5	44.5	41.5	38.5	36.0	33.0	-
50	7.00	55.5	52.5	49.5	46.5	43.5	40.0	37.5	-	-
55	7.50	57.5	54.5	51.5	48.5	45.0	42.0	-	-	-
60	8.00	59.5	56.5	53.5	50.0	46.5	43.5	-	-	-
65	8.50	61.5	58.5	55.0	51.5	48.0	45.0	-	-	-
70	9.00	63.5	60.0	56.5	53.0	49.5	46.0	-	-	-
75	9.50	65.0	61.5	58.0	54.5	51.0	-	-	-	-
80	10.00	67.0	63.0	59.5	56.0	52.0	-	-	-	-
Jack Pine, Lodgepole Pine, Red Pine										
20	4.00	-	-	32.5	30.5	28.5	26.5	24.5	22.5	21.0
25	5.00	-	-	36.0	33.5	31.0	29.0	27.0	25.0	23.0
30	5.50	-	-	39.0	36.5	34.0	31.5	29.0	27.0	25.0
35	6.00	-	-	41.5	38.5	36.0	33.5	31.0	28.5	26.5
40	6.00	-	-	44.0	41.0	38.0	35.5	33.0	30.5	-
45	6.50	-	-	46.0	43.0	40.0	37.0	34.5	32.0	-
50	7.00	-	-	48.0	45.0	42.0	39.0	36.0	-	-
55	7.50	-	-	49.5	46.5	43.5	40.5	-	-	-
60	8.00	-	-	51.5	48.0	45.0	42.0	-	-	-
65	8.50	-	-	53.0	49.5	46.0	43.0	-	-	-
70	9.00	-	-	54.5	51.0	47.5	44.5	-	-	-
75	9.50	-	-	56.0	52.5	49.0	-	-	-	-
80	10.00	-	-	57.5	54.0	50.5	-	-	-	-

Alaska Yellow Cedar										
20	4.00	-	-	31.5	29.5	27.5	25.5	23.5	22.0	20.0
25	5.00	-	-	34.5	32.5	30.0	28.0	26.0	24.0	22.0
30	5.50	-	-	37.5	35.0	32.5	30.0	28.0	26.0	24.0
35	6.00	45.0	42.5	40.0	37.5	35.0	32.0	30.0	27.5	25.5
40	6.00	47.5	45.0	42.0	39.5	37.0	34.0	31.5	29.0	25.5
45	6.50	49.5	47.0	44.0	41.5	38.5	36.0	33.0	30.5	-
50	7.00	51.5	49.0	46.0	43.0	40.0	37.5	34.5	-	-
55	7.50	53.5	50.5	47.5	44.5	41.5	39.0	-	-	-
60	8.00	55.5	52.5	49.5	46.0	43.0	40.0	-	-	-
65	8.50	57.0	54.0	51.0	47.5	44.5	41.5	-	-	-
70	9.00	58.5	55.5	52.5	49.0	46.0	42.5	-	-	-
75	9.50	60.0	57.0	53.5	50.5	47.0	-	-	-	-
80	10.00	61.5	58.5	55.0	51.5	48.5	-	-	-	-
Douglas Fir, Southern Pine										
20	4.00	-	-	31.0	29.0	27.0	25.0	23.0	21.0	19.5
25	5.00	-	-	33.5	31.5	29.5	27.5	25.5	23.0	21.5
30	5.50	-	-	36.5	34.0	32.0	29.5	27.5	25.0	23.5
35	6.00	43.5	41.5	39.0	36.5	34.0	31.5	29.0	27.0	25.0
40	6.00	46.0	43.5	41.0	38.5	36.0	33.5	31.0	28.5	-
45	6.50	48.5	45.5	43.0	40.5	37.5	35.0	32.5	30.0	-
50	7.00	50.5	47.5	45.0	42.0	39.0	36.5	34.0	-	-
55	7.50	52.0	49.5	46.5	43.5	40.5	38.0	-	-	-
60	8.00	54.0	51.0	48.0	45.0	42.0	39.0	-	-	-
65	8.50	55.5	52.5	49.5	46.5	43.5	40.5	-	-	-
70	9.00	57.0	54.0	51.0	48.0	45.0	41.5	-	-	-
75	9.50	59.0	55.5	52.5	49.0	46.0	-	-	-	-
80	10.00	60.0	57.0	54.0	50.5	47.0	-	-	-	-
Western Larch										
20	4.00	-	-	30.0	28.5	26.5	24.5	22.5	21.0	19.0
25	5.00	-	-	33.0	31.0	29.0	26.5	24.5	23.0	21.0
30	5.50	-	-	35.5	33.5	31.0	29.0	26.5	24.5	23.0
35	6.00	43.0	40.5	38.0	35.5	33.0	31.0	28.5	26.5	24.5
40	6.00	45.5	43.0	40.0	37.5	35.0	32.5	30.0	28.0	-
45	6.50	47.5	45.0	42.0	39.5	37.0	34.0	31.5	29.0	-
50	7.00	49.5	47.0	44.0	41.0	38.5	35.5	33.0	-	-
55	7.50	51.5	48.5	45.5	42.5	40.0	37.0	-	-	-
60	8.00	53.0	50.0	47.0	44.0	41.0	38.5	-	-	-
65	8.50	55.0	52.0	48.5	46.0	42.5	39.5	-	-	-
70	9.00	56.5	53.5	50.0	47.0	44.0	41.0	-	-	-
75	9.50	58.0	54.5	51.5	48.0	45.0	-	-	-	-
80	10.00	59.0	56.0	52.5	49.5	46.0	-	-	-	-

APPENDIX G. NESC ALLOWABLE WIND SPANS

NESC Light Loading District - Combined Ice and Wind

Grade B			No Telecommunications						2" Telecommunications							4" Telecommunications			
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,223	2,662	2,168	1,737	1,365	1,048	782	760	628	511	410	322	247	184	431	356	290	232	183	140	105
1∅ 1/O ACSR (6/1)	2,081	1,719	1,400	1,122	882	677	505	673	556	453	363	285	219	163	401	331	270	216	170	131	97
1∅ 4/O ACSR (6/1)	1,471	1,215	990	793	623	479	357	593	490	399	320	251	193	144	372	307	250	200	157	121	90
1∅ 336.4 ACSR (18/1)	1,211	1,000	815	653	513	394	294	546	451	367	294	231	178	133	352	291	237	190	149	115	86
1∅ 477.0 ACSR (18/1)	1,017	840	684	548	431	331	247	503	415	338	271	213	164	122	334	276	225	180	142	109	81
3∅ 4 ACSR (7/1)	1,584	1,308	1,066	854	671	515	384	611	505	411	329	259	199	148	378	313	255	204	160	123	92
3∅ 1/O ACSR (6/1)	1,023	845	688	551	433	333	248	504	416	339	272	214	164	122	335	276	225	180	142	109	81
3∅ 4/O ACSR (6/1)	723	597	486	390	306	235	175	419	346	282	226	177	136	102	295	243	198	159	125	96	72
3∅ 336.4 ACSR (18/1)	595	492	400	321	252	194	144	372	308	250	201	158	121	90	271	224	182	146	115	88	66
3∅ 477.0 ACSR (18/1)	500	413	336	270	212	163	121	333	275	224	179	141	108	81	249	206	168	134	106	81	61

Grade B			No Telecommunications						2" Telecommunications							4" Telecommunications			
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,128	2,567	2,073	1,642	1,271	954	687	773	634	512	406	314	236	170	441	362	292	231	179	134	97
1∅ 1/O ACSR (6/1)	2,020	1,658	1,339	1,061	820	616	444	680	558	451	357	276	207	150	409	336	271	215	166	125	90
1∅ 4/O ACSR (6/1)	1,428	1,172	946	750	580	435	314	597	490	396	313	243	182	131	377	310	250	198	153	115	83
1∅ 336.4 ACSR (18/1)	1,175	964	779	617	477	358	258	548	450	363	288	223	167	120	357	293	237	188	145	109	78
1∅ 477.0 ACSR (18/1)	988	810	655	519	401	301	217	503	413	334	264	204	153	111	338	277	224	177	137	103	74
3∅ 4 ACSR (7/1)	1,537	1,262	1,019	807	625	469	338	615	505	408	323	250	188	135	385	316	255	202	156	117	85
3∅ 1/O ACSR (6/1)	993	815	658	521	403	303	218	505	414	334	265	205	154	111	338	278	224	178	137	103	74
3∅ 4/O ACSR (6/1)	702	576	465	369	285	214	154	417	342	276	219	169	127	92	296	243	196	156	120	90	65
3∅ 336.4 ACSR (18/1)	578	474	383	303	235	176	127	370	303	245	194	150	113	81	272	223	180	143	110	83	60
3∅ 477.0 ACSR (18/1)	485	398	322	255	197	148	107	330	270	218	173	134	100	72	249	205	165	131	101	76	55

Grade B			No Telecommunications						2" Telecommunications							4" Telecommunications			
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,928	2,367	1,873	1,443	1,071	754	488	758	613	485	373	277	195	126	435	352	278	214	159	112	72
1∅ 1/O ACSR (6/1)	1,891	1,529	1,210	932	691	487	315	663	536	424	327	243	171	110	402	325	257	198	147	104	67
1∅ 4/O ACSR (6/1)	1,337	1,081	855	659	489	344	223	579	468	371	285	212	149	96	370	299	237	182	135	95	62
1∅ 336.4 ACSR (18/1)	1,100	889	704	542	402	283	183	530	428	339	261	194	136	88	349	282	223	172	128	90	58
1∅ 477.0 ACSR (18/1)	924	747	591	455	338	238	154	485	392	311	239	178	125	81	329	266	211	162	120	85	55
3∅ 4 ACSR (7/1)	1,439	1,164	921	709	526	371	240	598	483	382	294	219	154	100	377	305	241	186	138	97	63
3∅ 1/O ACSR (6/1)	929	751	595	458	340	239	155	487	394	311	240	178	125	81	330	267	211	162	121	85	55
3∅ 4/O ACSR (6/1)	657	531	420	324	240	169	109	400	323	256	197	146	103	67	287	232	184	142	105	74	48
3∅ 336.4 ACSR (18/1)	541	437	346	266	198	139	90	354	286	226	174	129	91	59	263	212	168	129	96	68	44
3∅ 477.0 ACSR (18/1)	454	367	291	224	166	117	76	315	254	201	155	115	81	52	241	194	154	119	88	62	40

Grade B			No Telecommunications						2" Telecommunications							4" Telecommunications			
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,691	2,130	1,636	1,205	833	516	250	718	568	437	322	222	138	67	414	328	252	186	128	79	39
1∅ 1/O ACSR (6/1)	1,737	1,375	1,056	778	538	333	162	626	496	381	281	194	120	58	382	302	232	171	118	73	36
1∅ 4/O ACSR (6/1)	1,228	972	747	550	380	236	114	545	431	331	244	169	105	51	350	277	213	157	108	67	33
1∅ 336.4 ACSR (18/1)	1,011	800	615	453	313	194	94	497	394	302	223	154	95	46	330	261	201	148	102	63	31
1∅ 477.0 ACSR (18/1)	850	672	517	381	263	163	79	455	360	277	204	141	87	42	311	246	189	139	96	60	29
3∅ 4 ACSR (7/1)	1,323	1,047	804	592	410	254	123	563	445	342	252	174	108	52	357	283	217	160	111	69	33
3∅ 1/O ACSR (6/1)	854	676	519	383	265	164	79	456	361	277	204	141	88	42	311	246	189	139	96	60	29
3∅ 4/O ACSR (6/1)	604	478	367	270	187	116	56	373	296	227	167	116	72	35	270	214	164	121	84	52	25
3∅ 336.4 ACSR (18/1)	497	393	302	223	154	95	46	330	261	200	148	102	63	31	247	195	150	110	76	47	23
3∅ 477.0 ACSR (18/1)	418	331	254	187	129	80	39	293	232	178	131	91	56	27	225	178	137	101	70	43	21

Grade B			No Telecommunications						2" Telecommunications							4" Telecommunications			
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,444	1,169	926	714	531	376	245	578	468	371	286	213	150	98	361	292	232	179	133	94	61
3∅ 1/O ACSR (6/1)	933	755	598	461	343	243	158	474	384	304	234	174	123	80	318	257	204	157	117	83	54
3∅ 4/O ACSR (6/1)	659	533	423	326	243	171	112	392	317	251	194	144	102	66	278	225	178	138	102	72	47
3∅ 336.4 ACSR (18/1)	543	439	348	268	200	141	92	347	281	223	172	128	90	59	255	207	164	126	94	66	43
3∅ 477.0 ACSR (18/1)	456	369	292	225	168	119	77	310	250	198	153	114	80	52	234	190	150	116	86	61	40

NESC Light Loading District - Combined Ice and Wind

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,150	874	631	420	237	81	-	477	363	262	174	98	34	-	301	229	165	110	62	21	-
3∅ 1/O ACSR (6/1)	742	564	408	271	153	52	-	389	296	214	142	80	27	-	263	200	145	96	54	19	-
3∅ 4/O ACSR (6/1)	525	399	288	192	108	37	-	319	243	175	117	66	23	-	230	175	126	84	47	16	-
3∅ 336.4 ACSR (18/1)	432	328	237	158	89	30	-	283	215	155	103	58	20	-	210	160	115	77	43	15	-
3∅ 477.0 ACSR (18/1)	363	276	199	132	75	26	-	251	191	138	92	52	18	-	192	146	106	70	40	14	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	802	526	283	71	-	-	-	341	224	120	30	-	-	-	217	142	77	19	-	-	-
3∅ 1/O ACSR (6/1)	518	340	183	46	-	-	-	276	181	98	25	-	-	-	189	124	67	17	-	-	-
3∅ 4/O ACSR (6/1)	366	240	129	33	-	-	-	226	149	80	20	-	-	-	164	108	58	15	-	-	-
3∅ 336.4 ACSR (18/1)	301	198	106	27	-	-	-	200	131	71	18	-	-	-	149	98	53	13	-	-	-
3∅ 477.0 ACSR (18/1)	253	166	89	23	-	-	-	177	116	63	16	-	-	-	137	90	48	12	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,367	1,092	849	637	455	299	168	605	483	376	282	201	132	74	388	310	241	181	129	85	48
3∅ 1/O ACSR (6/1)	883	705	548	412	294	193	108	487	389	302	227	162	106	60	336	268	209	157	112	73	41
3∅ 4/O ACSR (6/1)	624	498	388	291	208	136	77	396	316	246	185	132	87	49	290	232	180	135	96	63	36
3∅ 336.4 ACSR (18/1)	514	410	319	239	171	112	63	349	278	216	163	116	76	43	264	211	164	123	88	58	32
3∅ 477.0 ACSR (18/1)	432	345	268	201	144	94	53	309	247	192	144	103	67	38	240	192	149	112	80	53	30

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,317	1,041	798	586	404	248	117	566	447	343	252	174	107	50	360	285	219	161	111	68	32
3∅ 1/O ACSR (6/1)	850	672	515	379	261	160	76	458	362	278	204	140	86	41	313	248	190	140	96	59	28
3∅ 4/O ACSR (6/1)	601	475	364	268	184	113	53	374	296	227	167	115	70	33	272	215	165	121	83	51	24
3∅ 336.4 ACSR (18/1)	495	391	300	220	152	93	44	330	261	200	147	101	62	29	248	196	150	110	76	47	22
3∅ 477.0 ACSR (18/1)	416	329	252	185	127	78	37	293	232	178	130	90	55	26	226	179	137	101	69	43	20

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,207	932	689	477	294	139	8	531	410	303	210	130	61	3	341	263	194	135	83	39	2
3∅ 1/O ACSR (6/1)	780	602	445	308	190	89	5	428	330	244	169	104	49	3	295	228	168	117	72	34	2
3∅ 4/O ACSR (6/1)	551	425	314	218	134	63	4	349	269	199	138	85	40	2	255	197	145	101	62	29	2
3∅ 336.4 ACSR (18/1)	454	350	259	179	111	52	3	307	237	175	121	75	35	2	232	179	132	92	57	27	1
3∅ 477.0 ACSR (18/1)	381	294	217	151	93	44	2	272	210	155	107	66	31	2	211	163	121	84	52	24	1

NESC Light Loading District - Combined Ice and Wind

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,969	4,124	3,379	2,727	2,163	1,681	1,273	1,172	973	797	643	510	396	300	664	551	452	365	289	225	170
1∅ 1/O ACSR (6/1)	3,209	2,663	2,182	1,761	1,397	1,085	822	1,038	861	706	569	452	351	266	619	514	421	340	269	209	159
1∅ 4/O ACSR (6/1)	2,268	1,883	1,542	1,245	987	767	581	915	759	622	502	398	309	234	573	476	390	314	249	194	147
1∅ 336.4 ACSR (18/1)	1,867	1,550	1,270	1,025	813	631	478	842	699	573	462	367	285	216	544	451	370	298	237	184	139
1∅ 477.0 ACSR (18/1)	1,569	1,302	1,067	861	683	531	402	776	644	527	426	338	262	199	515	427	350	283	224	174	132
3∅ 4 ACSR (7/1)	2,443	2,027	1,661	1,340	1,063	826	626	942	782	641	517	410	319	241	584	484	397	320	254	197	150
3∅ 1/O ACSR (6/1)	1,577	1,309	1,072	866	687	533	404	778	645	529	427	338	263	199	516	428	351	283	225	174	132
3∅ 4/O ACSR (6/1)	1,115	925	758	612	485	377	286	646	536	439	354	281	218	165	454	377	309	249	198	154	116
3∅ 336.4 ACSR (18/1)	918	762	624	504	399	310	235	574	477	390	315	250	194	147	418	347	284	229	182	141	107
3∅ 477.0 ACSR (18/1)	771	640	524	423	336	261	198	513	426	349	282	223	174	131	384	319	261	211	167	130	99

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,861	4,016	3,271	2,619	2,055	1,573	1,165	1,201	992	808	647	508	388	288	685	566	461	369	290	222	164
1∅ 1/O ACSR (6/1)	3,139	2,593	2,112	1,691	1,327	1,015	753	1,058	874	712	570	447	342	254	636	525	428	343	269	206	152
1∅ 4/O ACSR (6/1)	2,219	1,833	1,493	1,196	938	718	532	928	767	624	500	392	300	222	587	485	395	316	248	190	141
1∅ 336.4 ACSR (18/1)	1,827	1,509	1,229	984	772	591	438	851	703	573	459	360	275	204	555	459	373	299	235	180	133
1∅ 477.0 ACSR (18/1)	1,535	1,268	1,033	827	649	497	368	782	646	526	421	331	253	188	525	434	353	283	222	170	126
3∅ 4 ACSR (7/1)	2,390	1,974	1,608	1,287	1,010	773	573	956	790	644	515	404	309	229	598	494	402	322	253	193	143
3∅ 1/O ACSR (6/1)	1,543	1,275	1,038	831	652	499	370	784	648	528	423	332	254	188	526	434	354	283	222	170	126
3∅ 4/O ACSR (6/1)	1,091	901	734	588	461	353	262	648	535	436	349	274	210	155	461	381	310	248	195	149	110
3∅ 336.4 ACSR (18/1)	898	742	604	484	380	290	215	574	475	386	309	243	186	138	422	349	284	228	179	137	101
3∅ 477.0 ACSR (18/1)	754	623	508	406	319	244	181	512	423	345	276	217	166	123	388	320	261	209	164	125	93

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,616	3,771	3,026	2,374	1,810	1,328	920	1,194	976	783	614	468	343	238	686	560	450	353	269	197	137
1∅ 1/O ACSR (6/1)	2,981	2,435	1,954	1,533	1,169	857	594	1,046	854	686	538	410	301	209	634	518	416	326	249	182	126
1∅ 4/O ACSR (6/1)	2,107	1,722	1,381	1,084	826	606	420	913	746	599	470	358	263	182	583	476	382	300	229	168	116
1∅ 336.4 ACSR (18/1)	1,734	1,417	1,137	892	680	499	346	835	682	548	430	328	240	167	550	449	361	283	216	158	110
1∅ 477.0 ACSR (18/1)	1,457	1,191	955	750	571	419	291	765	625	502	394	300	220	153	519	424	340	267	203	149	103
3∅ 4 ACSR (7/1)	2,269	1,854	1,487	1,167	890	653	452	942	770	618	485	369	271	188	595	486	390	306	233	171	119
3∅ 1/O ACSR (6/1)	1,465	1,197	960	754	575	421	292	767	627	503	395	301	221	153	520	425	341	267	204	149	104
3∅ 4/O ACSR (6/1)	1,036	846	679	533	406	298	207	631	515	413	324	247	181	126	453	370	297	233	178	130	90
3∅ 336.4 ACSR (18/1)	853	696	559	438	334	245	170	558	455	365	287	219	160	111	414	338	272	213	162	119	83
3∅ 477.0 ACSR (18/1)	716	585	470	368	281	206	143	496	405	325	255	194	143	99	379	310	249	195	149	109	76

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,302	3,457	2,712	2,060	1,496	1,013	606	1,148	922	724	550	399	270	162	662	532	417	317	230	156	93
1∅ 1/O ACSR (6/1)	2,778	2,232	1,751	1,330	966	654	391	1,001	805	631	479	348	236	141	611	491	385	292	212	144	86
1∅ 4/O ACSR (6/1)	1,964	1,578	1,238	940	683	463	277	871	700	549	417	303	205	123	560	450	353	268	195	132	79
1∅ 336.4 ACSR (18/1)	1,616	1,299	1,019	774	562	381	228	795	639	501	381	277	187	112	527	424	332	253	183	124	74
1∅ 477.0 ACSR (18/1)	1,358	1,091	856	650	472	320	191	727	584	458	348	253	171	102	497	399	313	238	173	117	70
3∅ 4 ACSR (7/1)	2,115	1,699	1,333	1,013	735	498	298	900	723	567	431	313	212	127	571	459	360	274	199	135	80
3∅ 1/O ACSR (6/1)	1,365	1,097	861	654	475	322	192	729	586	460	349	254	172	103	498	400	314	238	173	117	70
3∅ 4/O ACSR (6/1)	965	776	608	462	336	227	136	597	480	376	286	208	141	84	432	347	272	207	150	102	61
3∅ 336.4 ACSR (18/1)	795	638	501	380	276	187	112	527	424	332	252	183	124	74	394	317	249	189	137	93	56
3∅ 477.0 ACSR (18/1)	668	536	421	320	232	157	94	468	376	295	224	163	110	66	360	290	227	173	125	85	51

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,283	1,868	1,502	1,181	904	667	467	914	748	601	473	362	267	187	571	467	376	296	226	167	117
3∅ 1/O ACSR (6/1)	1,475	1,206	970	763	584	431	301	749	613	493	388	297	219	153	502	411	330	260	199	147	103
3∅ 4/O ACSR (6/1)	1,042	853	686	539	413	304	213	619	506	407	320	245	181	127	440	360	289	228	174	129	90
3∅ 336.4 ACSR (18/1)	858	702	564	444	340	251	175	549	449	361	284	217	160	112	404	330	265	209	160	118	83
3∅ 477.0 ACSR (18/1)	721	590	474	373	285	211	147	489	400	322	253	194	143	100	370	303	244	192	147	108	76

NESC Light Loading District - Combined Ice and Wind

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,922	1,507	1,140	820	543	306	105	798	626	474	341	225	127	44	504	395	299	215	142	80	28
3∅ 1/O ACSR (6/1)	1,241	973	736	529	350	197	68	650	510	386	277	184	103	36	440	345	261	188	124	70	24
3∅ 4/O ACSR (6/1)	877	688	521	374	248	139	48	534	419	317	228	151	85	29	384	301	228	164	108	61	21
3∅ 336.4 ACSR (18/1)	722	566	428	308	204	115	40	472	370	280	201	133	75	26	351	275	208	150	99	56	19
3∅ 477.0 ACSR (18/1)	607	476	360	259	171	96	33	420	329	249	179	119	67	23	321	252	191	137	91	51	18

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,459	1,043	677	357	79	-	-	621	444	288	152	34	-	-	394	282	183	96	21	-	-
3∅ 1/O ACSR (6/1)	942	674	437	230	51	-	-	503	360	233	123	27	-	-	343	245	159	84	19	-	-
3∅ 4/O ACSR (6/1)	666	476	309	163	36	-	-	412	295	191	101	22	-	-	298	213	138	73	16	-	-
3∅ 336.4 ACSR (18/1)	548	392	254	134	30	-	-	364	260	169	89	20	-	-	272	195	126	67	15	-	-
3∅ 477.0 ACSR (18/1)	461	329	214	113	25	-	-	323	231	150	79	18	-	-	249	178	115	61	14	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,174	1,759	1,393	1,072	795	558	358	962	778	616	474	352	247	158	618	500	396	305	226	158	102
3∅ 1/O ACSR (6/1)	1,404	1,136	899	692	513	360	231	774	626	496	382	283	199	127	534	432	342	264	195	137	88
3∅ 4/O ACSR (6/1)	993	803	636	490	363	255	163	630	510	404	311	230	162	104	462	373	296	228	169	118	76
3∅ 336.4 ACSR (18/1)	817	661	523	403	299	210	134	554	449	355	273	203	142	91	420	339	269	207	153	108	69
3∅ 477.0 ACSR (18/1)	687	555	440	339	251	176	113	491	397	315	242	180	126	81	382	309	245	189	140	98	63

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,109	1,693	1,327	1,006	729	492	292	906	728	570	433	313	212	125	577	464	363	276	200	135	80
3∅ 1/O ACSR (6/1)	1,362	1,093	857	650	471	318	188	733	589	462	350	254	171	102	502	403	316	240	174	117	69
3∅ 4/O ACSR (6/1)	963	773	606	459	333	225	133	600	481	377	286	207	140	83	435	350	274	208	151	102	60
3∅ 336.4 ACSR (18/1)	792	636	499	378	274	185	110	529	425	333	252	183	123	73	397	319	250	189	137	93	55
3∅ 477.0 ACSR (18/1)	666	535	419	318	230	155	92	469	377	295	224	162	109	65	362	291	228	173	125	85	50

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,959	1,544	1,177	857	580	343	142	862	679	518	377	255	151	63	553	435	332	242	164	97	40
3∅ 1/O ACSR (6/1)	1,265	997	760	553	374	221	92	694	547	417	304	205	121	50	479	377	288	209	142	84	35
3∅ 4/O ACSR (6/1)	894	705	537	391	265	156	65	566	446	340	247	167	99	41	414	326	249	181	122	72	30
3∅ 336.4 ACSR (18/1)	736	580	442	322	218	129	54	498	392	299	218	147	87	36	376	296	226	165	111	66	27
3∅ 477.0 ACSR (18/1)	619	487	372	271	183	108	45	441	348	265	193	131	77	32	343	270	206	150	101	60	25

NESC Medium Loading District - Combined Ice and Wind

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,054	1,710	1,407	1,141	910	712	545	1,103	918	755	612	488	382	292	754	627	516	418	334	261	200
1∅ 1/O ACSR (6/1)	1,792	1,492	1,227	995	794	621	475	1,023	851	700	568	453	354	271	715	596	490	397	317	248	190
1∅ 4/O ACSR (6/1)	1,560	1,299	1,068	866	691	541	414	942	785	645	523	417	327	250	675	562	462	375	299	234	179
1∅ 336.4 ACSR (18/1)	1,424	1,186	975	791	631	494	378	891	742	610	495	395	309	236	648	540	444	360	287	225	172
1∅ 477.0 ACSR (18/1)	1,303	1,084	892	723	577	452	345	842	701	576	467	373	292	223	622	518	426	345	275	216	165
3∅ 4 ACSR (7/1)	1,134	944	777	630	502	393	301	768	640	526	427	340	266	204	581	484	398	322	257	201	154
3∅ 1/O ACSR (6/1)	974	811	667	541	432	338	258	691	576	473	384	306	240	183	536	446	367	297	237	186	142
3∅ 4/O ACSR (6/1)	836	696	573	464	370	290	222	619	515	424	344	274	215	164	491	409	336	273	218	170	130
3∅ 336.4 ACSR (18/1)	758	631	519	421	336	263	201	575	479	394	319	255	199	152	463	385	317	257	205	160	123
3∅ 477.0 ACSR (18/1)	688	573	471	382	305	239	182	534	444	365	296	236	185	142	436	363	299	242	193	151	116

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,045	1,697	1,389	1,120	886	686	516	1,122	931	762	614	486	376	283	773	642	525	423	335	259	195
1∅ 1/O ACSR (6/1)	1,782	1,478	1,210	975	772	597	450	1,038	861	705	568	450	348	262	732	608	497	401	317	246	185
1∅ 4/O ACSR (6/1)	1,548	1,284	1,051	848	671	519	391	954	792	648	522	413	320	241	690	572	468	378	299	231	174
1∅ 336.4 ACSR (18/1)	1,412	1,172	959	773	612	473	356	901	747	612	493	390	302	227	661	549	449	362	287	222	167
1∅ 477.0 ACSR (18/1)	1,291	1,071	877	707	559	433	326	850	705	577	465	368	285	214	633	525	430	347	274	212	160
3∅ 4 ACSR (7/1)	1,123	931	762	615	486	376	283	774	642	525	423	335	259	195	590	490	401	323	256	198	149
3∅ 1/O ACSR (6/1)	963	799	654	527	417	323	243	694	576	472	380	301	233	175	543	450	369	297	235	182	137
3∅ 4/O ACSR (6/1)	826	686	561	452	358	277	209	620	515	421	340	269	208	157	496	412	337	272	215	166	125
3∅ 336.4 ACSR (18/1)	748	621	508	410	324	251	189	575	477	391	315	249	193	145	467	388	317	256	202	157	118
3∅ 477.0 ACSR (18/1)	679	564	461	372	294	228	171	534	443	362	292	231	179	135	439	364	298	241	190	147	111

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,981	1,628	1,317	1,044	807	604	433	1,111	914	739	586	453	339	243	772	635	513	407	315	236	169
1∅ 1/O ACSR (6/1)	1,723	1,416	1,145	908	702	526	376	1,025	843	681	540	418	313	224	730	600	485	385	297	223	159
1∅ 4/O ACSR (6/1)	1,495	1,229	994	788	609	456	327	940	773	625	495	383	287	205	686	563	456	361	279	209	150
1∅ 336.4 ACSR (18/1)	1,363	1,120	906	718	555	416	298	886	728	589	467	361	270	194	656	539	436	346	267	200	143
1∅ 477.0 ACSR (18/1)	1,244	1,023	827	656	507	380	272	834	686	555	440	340	255	182	628	516	417	331	256	191	137
3∅ 4 ACSR (7/1)	1,081	889	719	570	441	330	236	758	623	504	399	309	231	166	583	479	388	307	238	178	127
3∅ 1/O ACSR (6/1)	927	762	616	489	378	283	203	679	558	451	358	277	207	148	535	440	356	282	218	163	117
3∅ 4/O ACSR (6/1)	794	653	528	419	324	242	174	605	497	402	319	246	185	132	488	401	324	257	199	149	107
3∅ 336.4 ACSR (18/1)	719	591	478	379	293	219	157	560	460	372	295	228	171	122	459	377	305	242	187	140	100
3∅ 477.0 ACSR (18/1)	652	536	434	344	266	199	143	519	426	345	273	211	158	113	431	354	286	227	175	131	94

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,870	1,515	1,201	926	687	483	310	1,065	862	684	527	391	275	176	744	603	478	368	273	192	123
1∅ 1/O ACSR (6/1)	1,625	1,316	1,043	804	597	419	269	981	794	629	485	360	253	162	702	569	451	348	258	181	116
1∅ 4/O ACSR (6/1)	1,409	1,141	904	697	518	364	233	897	727	576	444	330	232	149	658	533	423	326	242	170	109
1∅ 336.4 ACSR (18/1)	1,283	1,039	824	635	472	331	212	845	684	542	418	310	218	140	630	510	404	312	231	163	104
1∅ 477.0 ACSR (18/1)	1,171	949	752	580	430	302	194	795	644	510	393	292	205	132	602	487	386	298	221	155	100
3∅ 4 ACSR (7/1)	1,017	824	653	503	374	263	168	721	584	463	357	265	186	119	558	452	358	276	205	144	92
3∅ 1/O ACSR (6/1)	872	706	560	431	320	225	144	644	522	414	319	237	166	107	511	414	328	253	188	132	85
3∅ 4/O ACSR (6/1)	746	605	479	369	274	193	124	573	464	368	284	211	148	95	465	377	299	230	171	120	77
3∅ 336.4 ACSR (18/1)	675	547	434	334	248	174	112	530	430	341	263	195	137	88	437	354	280	216	160	113	72
3∅ 477.0 ACSR (18/1)	613	496	393	303	225	158	101	491	398	315	243	180	127	81	410	332	263	203	151	106	68

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,084	892	723	575	447	337	244	747	615	498	397	308	232	168	569	469	380	302	235	177	128
3∅ 1/O ACSR (6/1)	930	766	621	494	384	289	210	670	552	447	356	277	209	151	524	431	350	278	216	163	118
3∅ 4/O ACSR (6/1)	798	657	532	424	329	248	180	599	493	400	318	247	186	135	479	395	320	255	198	149	108
3∅ 336.4 ACSR (18/1)	722	595	482	384	298	225	163	555	457	371	295	229	173	125	451	371	301	239	186	140	102
3∅ 477.0 ACSR (18/1)	656	540	438	348	271	204	148	515	424	344	274	213	160	116	424	349	283	225	175	132	96

NESC Medium Loading District - Combined Ice and Wind

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	944	751	581	432	303	193	99	661	526	407	303	213	135	69	509	405	314	233	164	104	53
3∅ 1/O ACSR (6/1)	809	644	498	371	260	165	85	592	472	365	271	190	121	62	467	372	288	214	150	95	49
3∅ 4/O ACSR (6/1)	693	552	427	318	223	141	73	528	420	325	242	170	108	55	426	339	262	195	137	87	45
3∅ 336.4 ACSR (18/1)	628	500	387	288	202	128	66	489	389	301	224	157	100	51	400	319	247	183	129	82	42
3∅ 477.0 ACSR (18/1)	570	453	351	261	183	116	60	453	360	279	207	145	92	47	376	299	231	172	121	77	39

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	742	549	378	228	99	-	-	526	389	268	162	70	-	-	407	301	207	125	54	-	-
3∅ 1/O ACSR (6/1)	636	470	324	196	85	-	-	470	348	239	145	63	-	-	373	276	190	115	50	-	-
3∅ 4/O ACSR (6/1)	545	403	277	168	72	-	-	418	309	213	129	56	-	-	340	251	173	105	45	-	-
3∅ 336.4 ACSR (18/1)	493	364	251	152	66	-	-	387	286	197	119	51	-	-	319	236	162	98	42	-	-
3∅ 477.0 ACSR (18/1)	447	331	228	138	59	-	-	358	265	182	110	48	-	-	299	221	152	92	40	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,052	857	685	534	404	292	197	758	618	494	385	291	210	142	593	483	386	301	228	165	111
3∅ 1/O ACSR (6/1)	900	733	586	457	346	250	169	676	551	440	344	260	188	127	542	441	353	275	208	150	101
3∅ 4/O ACSR (6/1)	770	628	502	391	296	214	144	600	489	391	305	230	167	112	492	401	320	250	189	136	92
3∅ 336.4 ACSR (18/1)	697	568	454	354	267	193	130	555	452	361	282	213	154	104	461	375	300	234	177	128	86
3∅ 477.0 ACSR (18/1)	632	515	411	321	242	175	118	513	418	334	260	197	142	96	431	351	281	219	166	120	81

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,018	824	653	503	373	262	167	725	587	465	358	266	186	119	563	455	361	278	206	145	93
3∅ 1/O ACSR (6/1)	872	706	559	431	320	224	143	647	524	415	320	237	167	107	515	417	330	255	189	132	85
3∅ 4/O ACSR (6/1)	747	604	479	369	274	192	123	576	466	369	285	211	148	95	468	379	301	232	172	120	77
3∅ 336.4 ACSR (18/1)	675	547	433	334	248	174	111	532	431	342	263	195	137	88	439	356	282	217	161	113	72
3∅ 477.0 ACSR (18/1)	613	496	393	303	225	158	101	493	399	316	244	181	127	81	412	334	264	204	151	106	68

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	953	759	587	437	306	194	100	686	546	422	314	220	140	72	536	426	330	245	172	109	56
3∅ 1/O ACSR (6/1)	816	650	503	374	262	166	85	612	487	377	280	196	125	64	489	390	301	224	157	100	51
3∅ 4/O ACSR (6/1)	699	556	430	320	224	142	73	543	432	335	249	174	111	57	445	354	274	204	143	91	46
3∅ 336.4 ACSR (18/1)	632	503	389	289	203	129	66	502	400	309	230	161	102	52	417	332	256	191	134	85	44
3∅ 477.0 ACSR (18/1)	573	456	353	262	184	117	60	464	369	286	213	149	95	48	390	311	240	179	125	79	41

NESC Medium Loading District - Combined Ice and Wind

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,101	2,586	2,132	1,734	1,388	1,091	839	1,664	1,388	1,144	931	745	586	450	1,138	949	782	636	509	400	308
1∅ 1/O ACSR (6/1)	2,705	2,257	1,860	1,513	1,211	952	732	1,543	1,287	1,061	863	691	543	418	1,080	901	742	604	483	380	292
1∅ 4/O ACSR (6/1)	2,354	1,964	1,619	1,316	1,054	828	637	1,422	1,187	978	795	637	500	385	1,019	850	701	570	456	358	276
1∅ 336.4 ACSR (18/1)	2,150	1,793	1,478	1,202	962	756	582	1,345	1,122	925	752	602	473	364	979	816	673	547	438	344	265
1∅ 477.0 ACSR (18/1)	1,966	1,640	1,352	1,099	880	692	532	1,271	1,060	874	711	569	447	344	939	783	646	525	420	330	254
3∅ 4 ACSR (7/1)	1,712	1,428	1,177	957	766	602	463	1,159	967	797	648	519	408	314	877	731	603	490	392	308	237
3∅ 1/O ACSR (6/1)	1,471	1,227	1,011	822	658	517	398	1,044	870	718	583	467	367	282	809	675	556	452	362	284	219
3∅ 4/O ACSR (6/1)	1,262	1,053	868	706	565	444	342	934	779	642	522	418	329	253	741	618	510	415	332	261	201
3∅ 336.4 ACSR (18/1)	1,144	954	786	639	512	402	309	868	724	596	485	388	305	235	699	583	481	391	313	246	189
3∅ 477.0 ACSR (18/1)	1,039	866	714	581	465	365	281	806	672	554	451	361	283	218	658	549	453	368	295	232	178

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,097	2,576	2,116	1,713	1,362	1,061	806	1,700	1,414	1,161	940	748	582	442	1,171	974	800	648	515	401	305
1∅ 1/O ACSR (6/1)	2,698	2,244	1,843	1,492	1,187	925	702	1,572	1,308	1,074	869	691	539	409	1,109	923	758	613	488	380	289
1∅ 4/O ACSR (6/1)	2,344	1,950	1,602	1,296	1,031	803	610	1,445	1,202	987	799	636	495	376	1,044	869	714	577	459	358	272
1∅ 336.4 ACSR (18/1)	2,139	1,779	1,461	1,183	941	733	557	1,364	1,135	932	754	600	467	355	1,002	833	684	554	440	343	261
1∅ 477.0 ACSR (18/1)	1,955	1,626	1,335	1,081	860	670	509	1,287	1,070	879	712	566	441	335	959	798	655	530	422	329	250
3∅ 4 ACSR (7/1)	1,700	1,414	1,161	940	748	583	443	1,171	974	800	648	515	401	305	894	743	610	494	393	306	233
3∅ 1/O ACSR (6/1)	1,459	1,214	997	807	642	500	380	1,052	875	718	581	463	360	274	822	684	562	455	362	282	214
3∅ 4/O ACSR (6/1)	1,251	1,041	855	692	550	429	326	939	781	642	519	413	322	245	752	625	514	416	331	258	196
3∅ 336.4 ACSR (18/1)	1,133	943	774	626	498	388	295	871	725	595	482	383	298	227	707	588	483	391	311	242	184
3∅ 477.0 ACSR (18/1)	1,029	856	703	569	452	352	268	808	672	552	447	355	277	210	665	553	455	368	293	228	173

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,018	2,491	2,025	1,616	1,262	957	699	1,693	1,398	1,136	907	708	537	392	1,177	971	790	630	492	373	272
1∅ 1/O ACSR (6/1)	2,625	2,166	1,761	1,406	1,097	832	608	1,562	1,289	1,048	837	653	495	362	1,112	918	746	595	465	353	257
1∅ 4/O ACSR (6/1)	2,278	1,880	1,528	1,220	952	722	527	1,432	1,182	961	767	599	454	332	1,044	862	701	559	437	331	242
1∅ 336.4 ACSR (18/1)	2,076	1,713	1,393	1,112	868	658	481	1,350	1,114	906	723	564	428	312	1,000	825	671	535	418	317	231
1∅ 477.0 ACSR (18/1)	1,896	1,565	1,272	1,015	793	601	439	1,271	1,049	853	681	531	403	294	956	789	641	512	400	303	221
3∅ 4 ACSR (7/1)	1,647	1,360	1,105	882	689	522	381	1,154	953	774	618	483	366	267	889	733	596	476	371	282	206
3∅ 1/O ACSR (6/1)	1,412	1,166	948	756	590	448	327	1,034	853	694	554	432	328	239	815	673	547	437	341	259	189
3∅ 4/O ACSR (6/1)	1,210	999	812	648	506	384	280	921	760	618	493	385	292	213	744	614	499	398	311	236	172
3∅ 336.4 ACSR (18/1)	1,095	904	735	587	458	347	254	853	704	572	457	357	271	197	699	577	469	374	292	222	162
3∅ 477.0 ACSR (18/1)	994	820	667	532	415	315	230	790	652	530	423	330	251	183	656	541	440	351	274	208	152

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,868	2,336	1,867	1,455	1,097	790	530	1,633	1,330	1,063	828	625	450	302	1,141	930	743	579	437	314	211
1∅ 1/O ACSR (6/1)	2,492	2,030	1,622	1,264	953	686	460	1,504	1,225	979	763	575	414	278	1,077	877	701	546	412	297	199
1∅ 4/O ACSR (6/1)	2,160	1,760	1,406	1,096	826	595	399	1,376	1,121	896	698	526	379	254	1,010	822	657	512	386	278	186
1∅ 336.4 ACSR (18/1)	1,968	1,603	1,281	998	753	542	363	1,296	1,055	843	657	496	357	239	966	787	628	490	369	266	178
1∅ 477.0 ACSR (18/1)	1,796	1,463	1,169	911	687	495	332	1,219	993	793	618	466	336	225	922	751	600	468	353	254	170
3∅ 4 ACSR (7/1)	1,560	1,271	1,015	791	597	430	288	1,105	900	719	561	423	304	204	856	697	557	434	327	236	158
3∅ 1/O ACSR (6/1)	1,336	1,089	870	678	511	368	247	988	805	643	501	378	272	182	784	639	510	398	300	216	145
3∅ 4/O ACSR (6/1)	1,145	932	745	581	438	315	211	879	716	572	446	336	242	162	714	581	464	362	273	197	132
3∅ 336.4 ACSR (18/1)	1,036	844	674	525	396	285	191	813	663	529	413	311	224	150	670	546	436	340	256	185	124
3∅ 477.0 ACSR (18/1)	940	765	611	477	359	259	174	753	613	490	382	288	207	139	628	512	409	319	240	173	116

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,652	1,366	1,114	892	700	535	395	1,138	941	767	615	482	368	272	868	718	585	469	368	281	207
3∅ 1/O ACSR (6/1)	1,418	1,173	956	766	601	459	339	1,022	845	689	552	433	331	244	799	661	539	431	338	259	191
3∅ 4/O ACSR (6/1)	1,216	1,006	820	657	515	394	291	913	755	615	493	387	295	218	731	604	492	395	310	236	175
3∅ 336.4 ACSR (18/1)	1,101	911	742	595	466	356	263	847	700	571	457	359	274	202	688	569	463	371	291	223	164
3∅ 477.0 ACSR (18/1)	1,000	827	674	540	423	324	239	785	649	529	424	333	254	188	647	535	436	349	274	209	154

NESC Medium Loading District - Combined Ice and Wind

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,471	1,183	929	706	512	346	205	1,031	829	651	494	359	242	143	793	638	501	381	276	186	110
3∅ 1/O ACSR (6/1)	1,261	1,014	796	605	439	296	175	923	742	583	443	321	217	128	728	586	460	349	253	171	101
3∅ 4/O ACSR (6/1)	1,081	869	682	518	376	254	150	823	662	519	395	286	193	114	664	534	419	319	231	156	92
3∅ 336.4 ACSR (18/1)	978	787	617	469	340	230	136	762	613	481	365	265	179	106	624	502	394	299	217	147	87
3∅ 477.0 ACSR (18/1)	888	714	560	426	309	209	124	706	568	446	339	246	166	98	586	471	370	281	204	138	82

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,192	903	648	424	229	62	-	845	640	459	300	163	44	-	654	496	355	233	126	34	-
3∅ 1/O ACSR (6/1)	1,022	774	555	363	197	53	-	755	572	410	269	145	40	-	599	454	326	213	115	31	-
3∅ 4/O ACSR (6/1)	875	663	475	311	168	46	-	672	509	365	239	129	35	-	546	413	296	194	105	29	-
3∅ 336.4 ACSR (18/1)	792	600	430	281	152	41	-	622	471	338	221	120	33	-	512	388	278	182	99	27	-
3∅ 477.0 ACSR (18/1)	718	544	390	255	138	38	-	576	436	313	205	111	30	-	480	364	261	171	92	25	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,608	1,317	1,060	834	639	470	328	1,160	950	764	602	461	339	236	907	743	598	471	360	265	185
3∅ 1/O ACSR (6/1)	1,377	1,128	907	714	547	403	281	1,034	847	682	537	411	303	211	828	679	546	430	329	242	169
3∅ 4/O ACSR (6/1)	1,178	965	776	611	468	345	240	918	752	605	476	365	269	187	752	616	496	390	299	220	153
3∅ 336.4 ACSR (18/1)	1,065	873	702	553	423	312	217	848	695	559	440	337	248	173	705	577	464	366	280	206	144
3∅ 477.0 ACSR (18/1)	966	791	637	501	384	283	197	784	642	517	407	311	229	160	660	540	435	342	262	193	135

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,562	1,272	1,016	792	597	429	288	1,112	906	723	564	425	306	205	863	703	562	438	330	237	159
3∅ 1/O ACSR (6/1)	1,338	1,090	870	678	511	368	246	993	809	646	504	380	273	183	790	643	514	400	302	217	145
3∅ 4/O ACSR (6/1)	1,145	933	745	581	438	315	211	883	719	575	448	338	243	163	719	585	468	364	275	198	132
3∅ 336.4 ACSR (18/1)	1,036	844	674	525	396	285	191	817	665	531	414	312	225	150	674	549	439	342	258	185	124
3∅ 477.0 ACSR (18/1)	940	766	612	476	359	258	173	756	616	492	383	289	208	139	632	515	411	320	242	174	116

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,472	1,181	924	698	503	335	192	1,059	850	665	503	362	241	138	827	663	519	392	283	188	108
3∅ 1/O ACSR (6/1)	1,260	1,011	791	598	430	287	165	945	758	593	448	323	215	124	755	606	474	359	258	172	99
3∅ 4/O ACSR (6/1)	1,078	865	677	512	368	245	141	839	673	526	398	287	191	110	686	551	431	326	234	156	90
3∅ 336.4 ACSR (18/1)	975	782	612	463	333	222	128	775	622	486	368	265	176	101	643	516	404	305	220	146	84
3∅ 477.0 ACSR (18/1)	884	710	555	420	302	201	116	716	575	450	340	245	163	94	602	483	378	286	206	137	79

NESC Heavy Loading District - Combined Ice and Wind

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,185	986	811	658	525	411	314	791	659	542	439	350	274	210	594	494	407	330	263	206	157
1∅ 1/O ACSR (6/1)	1,093	910	748	607	484	379	290	749	624	513	416	332	260	199	570	474	390	316	252	197	151
1∅ 4/O ACSR (6/1)	1,002	834	686	556	444	347	266	705	587	483	391	312	244	187	544	453	372	302	241	189	144
1∅ 336.4 ACSR (18/1)	944	786	646	524	418	327	250	676	563	463	375	299	234	179	526	438	360	292	233	182	140
1∅ 477.0 ACSR (18/1)	889	740	609	494	394	308	236	647	539	443	359	287	224	172	509	424	348	283	225	176	135
3∅ 4 ACSR (7/1)	667	555	457	370	295	231	177	521	434	357	289	231	181	138	427	356	293	237	189	148	113
3∅ 1/O ACSR (6/1)	608	506	416	338	269	211	161	484	403	332	269	215	168	128	402	335	276	223	178	140	107
3∅ 4/O ACSR (6/1)	551	459	377	306	244	191	146	448	373	307	249	198	155	119	377	314	258	209	167	131	100
3∅ 336.4 ACSR (18/1)	516	430	353	286	229	179	137	424	353	290	235	188	147	112	360	300	246	200	159	125	95
3∅ 477.0 ACSR (18/1)	483	402	331	268	214	167	128	401	334	275	223	178	139	106	343	286	235	191	152	119	91

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,182	981	803	647	512	396	298	801	665	544	439	347	269	202	606	503	412	332	263	203	153
1∅ 1/O ACSR (6/1)	1,089	903	740	596	472	365	275	757	628	514	415	328	254	191	581	482	394	318	252	195	147
1∅ 4/O ACSR (6/1)	997	827	677	546	432	334	252	712	590	483	390	308	239	180	553	459	376	303	240	186	140
1∅ 336.4 ACSR (18/1)	939	779	638	514	407	315	237	682	565	463	373	295	229	172	535	444	363	293	232	179	135
1∅ 477.0 ACSR (18/1)	884	733	600	484	383	296	223	652	541	443	357	282	219	165	517	429	351	283	224	173	130
3∅ 4 ACSR (7/1)	661	548	449	362	286	222	167	522	433	355	286	226	175	132	432	358	293	236	187	145	109
3∅ 1/O ACSR (6/1)	602	500	409	330	261	202	152	485	402	329	265	210	163	122	406	337	276	222	176	136	102
3∅ 4/O ACSR (6/1)	546	453	371	299	236	183	138	447	371	304	245	194	150	113	379	315	258	208	164	127	96
3∅ 336.4 ACSR (18/1)	510	423	347	279	221	171	129	424	351	288	232	183	142	107	362	300	246	198	157	121	91
3∅ 477.0 ACSR (18/1)	477	396	324	261	207	160	120	401	332	272	219	174	134	101	345	286	234	189	149	116	87

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,147	943	762	605	468	350	251	789	649	525	416	322	241	172	602	495	400	317	245	184	131
1∅ 1/O ACSR (6/1)	1,056	868	702	556	430	322	231	745	612	495	393	304	227	163	576	473	383	303	235	176	126
1∅ 4/O ACSR (6/1)	965	793	642	509	393	295	211	699	574	465	368	285	213	153	548	450	364	289	223	167	120
1∅ 336.4 ACSR (18/1)	908	747	604	479	370	277	198	669	550	444	352	272	204	146	529	435	352	279	216	161	116
1∅ 477.0 ACSR (18/1)	854	702	568	450	348	261	187	639	525	425	337	260	195	140	510	419	339	269	208	156	111
3∅ 4 ACSR (7/1)	637	524	424	336	260	194	139	509	418	338	268	207	155	111	424	348	282	223	173	129	93
3∅ 1/O ACSR (6/1)	580	477	386	306	237	177	127	472	388	314	249	192	144	103	398	327	264	210	162	121	87
3∅ 4/O ACSR (6/1)	525	432	349	277	214	160	115	435	358	289	229	177	133	95	371	305	247	196	151	113	81
3∅ 336.4 ACSR (18/1)	491	404	327	259	200	150	107	412	338	274	217	168	126	90	354	291	235	187	144	108	77
3∅ 477.0 ACSR (18/1)	459	378	305	242	187	140	100	389	320	258	205	158	119	85	337	277	224	178	137	103	74

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,085	878	696	537	398	280	180	754	611	484	373	277	195	125	578	468	371	286	212	149	96
1∅ 1/O ACSR (6/1)	997	808	640	494	366	257	165	711	575	456	352	261	183	118	552	447	354	273	203	142	91
1∅ 4/O ACSR (6/1)	911	738	585	451	335	235	151	666	539	427	330	245	172	110	525	425	337	260	193	135	87
1∅ 336.4 ACSR (18/1)	857	694	550	424	315	221	142	637	515	409	315	234	164	105	506	410	325	251	186	131	84
1∅ 477.0 ACSR (18/1)	806	653	517	399	296	208	133	608	492	390	301	223	157	101	488	395	313	241	179	126	81
3∅ 4 ACSR (7/1)	600	486	385	297	220	155	99	483	391	310	239	177	125	80	404	327	259	200	148	104	67
3∅ 1/O ACSR (6/1)	546	442	351	270	201	141	90	447	362	287	221	164	115	74	379	307	243	187	139	98	63
3∅ 4/O ACSR (6/1)	494	400	317	245	182	128	82	412	334	264	204	151	106	68	353	286	227	175	130	91	58
3∅ 336.4 ACSR (18/1)	462	374	297	229	170	119	77	389	315	250	193	143	100	64	336	272	216	166	124	87	56
3∅ 477.0 ACSR (18/1)	432	350	277	214	159	111	71	368	298	236	182	135	95	61	320	259	205	158	118	83	53

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	638	525	426	339	263	199	144	504	415	336	268	208	157	114	417	343	278	221	172	130	94
3∅ 1/O ACSR (6/1)	581	479	388	309	240	181	131	468	385	312	249	193	146	105	392	323	261	208	162	122	88
3∅ 4/O ACSR (6/1)	527	434	352	280	217	164	119	432	356	288	229	178	134	97	366	301	244	194	151	114	82
3∅ 336.4 ACSR (18/1)	493	406	329	262	203	153	111	409	337	273	217	169	127	92	349	288	233	186	144	109	79
3∅ 477.0 ACSR (18/1)	461	379	308	245	190	143	104	387	318	258	205	160	120	87	333	274	222	177	137	104	75

NESC Heavy Loading District - Combined Ice and Wind

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	556	443	343	255	179	113	58	444	354	274	204	143	91	47	370	295	228	170	119	75	39
3∅ 1/O ACSR (6/1)	507	403	312	232	163	103	53	412	328	254	189	132	84	43	347	277	214	159	112	71	36
3∅ 4/O ACSR (6/1)	459	365	282	210	147	94	48	380	302	234	174	122	77	40	324	258	200	148	104	66	34
3∅ 336.4 ACSR (18/1)	429	341	264	196	138	87	45	359	286	221	165	115	73	38	309	246	190	142	99	63	32
3∅ 477.0 ACSR (18/1)	401	319	247	184	129	82	42	339	270	209	155	109	69	36	294	234	181	135	95	60	31

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	438	324	223	135	58	-	-	352	260	179	108	47	-	-	295	218	150	91	39	-	-
3∅ 1/O ACSR (6/1)	398	295	203	123	53	-	-	326	241	166	100	43	-	-	276	204	141	85	37	-	-
3∅ 4/O ACSR (6/1)	361	267	184	111	48	-	-	301	222	153	93	40	-	-	258	190	131	79	34	-	-
3∅ 336.4 ACSR (18/1)	337	249	172	104	45	-	-	284	210	145	87	38	-	-	245	181	125	76	33	-	-
3∅ 477.0 ACSR (18/1)	315	233	160	97	42	-	-	268	198	137	83	36	-	-	234	173	119	72	31	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	621	506	404	316	238	172	116	506	412	329	257	194	140	95	426	347	278	217	164	118	80
3∅ 1/O ACSR (6/1)	565	460	368	287	217	157	106	468	381	305	238	180	130	88	399	325	260	203	153	111	75
3∅ 4/O ACSR (6/1)	511	416	333	260	196	142	96	430	350	280	219	165	119	81	371	303	242	189	143	103	70
3∅ 336.4 ACSR (18/1)	477	389	311	243	183	132	89	406	331	264	206	156	113	76	353	288	230	180	136	98	66
3∅ 477.0 ACSR (18/1)	446	363	290	227	171	124	84	383	312	250	195	147	106	72	336	274	219	171	129	93	63

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	601	486	385	297	220	154	99	485	393	311	240	178	125	80	406	329	261	201	149	105	67
3∅ 1/O ACSR (6/1)	547	443	351	270	200	141	90	449	364	288	222	165	115	74	381	308	244	188	140	98	63
3∅ 4/O ACSR (6/1)	495	400	317	244	181	127	81	413	335	265	204	152	106	68	355	287	228	175	130	91	58
3∅ 336.4 ACSR (18/1)	462	374	297	228	169	119	76	390	316	251	193	143	100	64	338	274	217	167	124	87	56
3∅ 477.0 ACSR (18/1)	432	350	277	214	158	111	71	369	298	237	182	135	95	61	322	260	206	159	118	83	53

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	563	448	347	258	181	115	59	458	364	282	210	147	93	48	385	307	237	177	124	79	40
3∅ 1/O ACSR (6/1)	512	408	315	235	164	104	53	423	337	261	194	136	86	44	361	287	222	165	116	74	38
3∅ 4/O ACSR (6/1)	463	369	285	212	149	94	48	389	310	240	178	125	79	41	336	267	207	154	108	68	35
3∅ 336.4 ACSR (18/1)	433	345	267	198	139	88	45	368	293	226	168	118	75	38	320	254	197	146	103	65	33
3∅ 477.0 ACSR (18/1)	404	322	249	185	130	82	42	347	276	214	159	111	71	36	304	242	187	139	98	62	32

NESC Heavy Loading District - Combined Ice and Wind

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,788	1,492	1,230	1,000	800	629	484	1,194	996	821	668	534	420	323	896	748	616	501	401	315	243
1∅ 1/O ACSR (6/1)	1,649	1,376	1,134	922	738	580	446	1,131	943	777	632	506	398	306	860	717	591	481	385	303	233
1∅ 4/O ACSR (6/1)	1,512	1,261	1,040	845	677	532	409	1,064	888	732	595	476	374	288	821	685	565	459	367	289	222
1∅ 336.4 ACSR (18/1)	1,425	1,189	980	797	638	501	386	1,020	851	702	570	457	359	276	795	663	546	444	356	280	215
1∅ 477.0 ACSR (18/1)	1,342	1,119	923	750	601	472	363	977	815	672	546	437	344	264	768	641	528	430	344	270	208
3∅ 4 ACSR (7/1)	1,006	839	692	563	450	354	272	786	656	541	440	352	277	213	645	538	444	361	289	227	175
3∅ 1/O ACSR (6/1)	918	766	631	513	411	323	248	731	610	503	409	327	257	198	608	507	418	340	272	214	164
3∅ 4/O ACSR (6/1)	832	694	572	465	372	293	225	676	564	465	378	302	238	183	569	474	391	318	255	200	154
3∅ 336.4 ACSR (18/1)	779	650	536	435	349	274	211	640	534	440	358	287	225	173	543	453	374	304	243	191	147
3∅ 477.0 ACSR (18/1)	729	608	501	407	326	256	197	606	505	417	339	271	213	164	518	432	356	290	232	182	140

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,790	1,489	1,223	990	787	613	466	1,213	1,009	829	671	534	416	316	918	763	627	507	404	314	239
1∅ 1/O ACSR (6/1)	1,649	1,372	1,127	912	725	565	429	1,147	954	784	634	504	393	299	879	731	601	486	387	301	229
1∅ 4/O ACSR (6/1)	1,510	1,256	1,031	835	664	517	393	1,078	897	736	596	474	369	281	838	697	573	463	369	287	218
1∅ 336.4 ACSR (18/1)	1,422	1,183	971	786	625	487	370	1,032	859	705	571	454	354	269	810	674	554	448	356	278	211
1∅ 477.0 ACSR (18/1)	1,338	1,113	914	740	588	458	348	987	821	675	546	434	338	257	782	651	534	433	344	268	204
3∅ 4 ACSR (7/1)	1,001	832	684	553	440	343	261	791	658	540	437	348	271	206	654	544	446	361	287	224	170
3∅ 1/O ACSR (6/1)	912	759	623	504	401	313	237	734	611	502	406	323	252	191	614	511	420	340	270	211	160
3∅ 4/O ACSR (6/1)	826	687	565	457	363	283	215	678	564	463	375	298	232	176	574	478	392	318	253	197	150
3∅ 336.4 ACSR (18/1)	773	643	528	427	340	265	201	641	534	438	355	282	220	167	548	456	374	303	241	188	143
3∅ 477.0 ACSR (18/1)	723	601	494	400	318	248	188	607	505	414	335	267	208	158	522	435	357	289	230	179	136

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,748	1,442	1,173	936	731	554	405	1,203	993	807	644	503	381	278	917	757	615	491	383	291	212
1∅ 1/O ACSR (6/1)	1,608	1,327	1,079	861	672	510	372	1,135	937	761	608	474	360	263	877	724	588	470	367	278	203
1∅ 4/O ACSR (6/1)	1,471	1,214	987	788	615	466	340	1,065	879	714	570	445	338	246	835	689	560	447	349	265	193
1∅ 336.4 ACSR (18/1)	1,384	1,142	929	741	579	439	320	1,019	841	683	546	426	323	236	806	665	541	432	337	256	187
1∅ 477.0 ACSR (18/1)	1,302	1,074	873	697	544	413	301	973	803	653	521	407	309	225	777	641	521	416	325	246	180
3∅ 4 ACSR (7/1)	971	801	651	520	406	308	225	776	640	520	415	324	246	180	646	533	433	346	270	205	149
3∅ 1/O ACSR (6/1)	884	730	593	474	370	280	205	719	594	483	385	301	228	167	606	500	407	325	253	192	140
3∅ 4/O ACSR (6/1)	801	661	537	429	335	254	185	663	547	445	355	277	210	153	566	467	380	303	236	179	131
3∅ 336.4 ACSR (18/1)	749	618	502	401	313	237	173	627	517	421	336	262	199	145	539	445	362	289	225	171	125
3∅ 477.0 ACSR (18/1)	700	578	469	375	293	222	162	592	489	397	317	248	188	137	514	424	345	275	215	163	119

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,663	1,355	1,082	843	636	458	307	1,156	942	752	586	442	318	213	886	722	577	449	339	244	164
1∅ 1/O ACSR (6/1)	1,529	1,246	995	776	585	421	282	1,090	888	709	553	417	300	201	846	689	551	429	324	233	156
1∅ 4/O ACSR (6/1)	1,397	1,138	909	709	535	385	258	1,021	832	665	518	391	281	189	804	655	524	408	308	222	149
1∅ 336.4 ACSR (18/1)	1,314	1,071	855	667	503	362	243	976	795	635	495	373	269	180	776	632	505	394	297	214	143
1∅ 477.0 ACSR (18/1)	1,236	1,007	804	627	473	340	228	932	759	606	473	356	257	172	748	609	487	379	286	206	138
3∅ 4 ACSR (7/1)	920	749	599	467	352	253	170	740	603	482	376	283	204	137	619	505	403	314	237	171	114
3∅ 1/O ACSR (6/1)	837	682	545	425	320	231	155	686	559	446	348	262	189	127	581	473	378	295	222	160	107
3∅ 4/O ACSR (6/1)	758	617	493	384	290	209	140	632	515	411	320	242	174	117	541	441	352	275	207	149	100
3∅ 336.4 ACSR (18/1)	708	577	461	359	271	195	131	597	486	389	303	228	164	110	516	420	336	262	197	142	95
3∅ 477.0 ACSR (18/1)	662	539	431	336	253	182	122	564	459	367	286	216	155	104	491	400	319	249	188	135	91

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	973	804	656	525	412	315	232	768	635	518	415	326	249	184	635	525	428	343	269	206	152
3∅ 1/O ACSR (6/1)	886	733	597	479	375	287	212	714	590	481	385	302	231	170	597	494	403	322	253	193	143
3∅ 4/O ACSR (6/1)	803	664	541	434	340	260	192	659	545	444	356	279	213	157	558	462	376	301	236	181	133
3∅ 336.4 ACSR (18/1)	751	621	506	406	318	243	179	623	515	420	337	264	202	149	533	440	359	288	226	172	127
3∅ 477.0 ACSR (18/1)	703	581	474	379	298	227	168	589	487	397	318	250	191	141	508	420	342	274	215	164	121

NESC Heavy Loading District - Combined Ice and Wind

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	867	697	547	416	302	204	121	693	557	437	332	241	163	96	577	464	364	277	201	136	80
3∅ 1/O ACSR (6/1)	789	635	498	379	275	186	110	642	517	405	308	224	151	89	541	435	342	260	188	127	75
3∅ 4/O ACSR (6/1)	715	575	451	343	249	168	99	592	476	374	284	206	139	82	505	406	319	242	176	119	70
3∅ 336.4 ACSR (18/1)	668	538	422	321	233	157	93	560	450	353	269	195	132	78	482	387	304	231	168	113	67
3∅ 477.0 ACSR (18/1)	625	503	394	300	217	147	87	529	425	334	254	184	124	74	458	369	289	220	160	108	64

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	703	533	382	250	135	37	-	566	429	307	201	109	30	-	474	359	257	168	91	25	-
3∅ 1/O ACSR (6/1)	640	485	348	228	123	34	-	524	397	285	186	101	27	-	444	336	241	158	85	23	-
3∅ 4/O ACSR (6/1)	579	439	315	206	111	30	-	483	366	262	172	93	25	-	414	314	225	147	80	22	-
3∅ 336.4 ACSR (18/1)	542	410	294	193	104	28	-	456	346	248	162	88	24	-	394	299	214	140	76	21	-
3∅ 477.0 ACSR (18/1)	506	384	275	180	97	26	-	431	326	234	153	83	23	-	375	284	204	133	72	20	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	950	778	626	493	377	278	194	773	633	510	401	307	226	158	652	534	430	338	259	191	133
3∅ 1/O ACSR (6/1)	864	708	569	448	343	253	176	715	586	471	371	284	209	146	610	500	402	317	242	179	124
3∅ 4/O ACSR (6/1)	781	640	515	405	310	229	159	658	539	434	341	261	192	134	568	465	374	295	226	166	116
3∅ 336.4 ACSR (18/1)	730	598	481	379	290	214	149	621	509	409	322	247	182	127	540	443	356	280	215	158	110
3∅ 477.0 ACSR (18/1)	682	559	450	354	271	200	139	586	480	386	304	233	171	119	514	421	339	266	204	150	105

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	921	750	599	467	352	253	170	744	606	484	377	284	205	137	624	508	406	316	238	171	115
3∅ 1/O ACSR (6/1)	839	683	546	425	320	231	154	689	561	448	349	263	189	127	585	476	380	296	223	161	108
3∅ 4/O ACSR (6/1)	759	618	494	385	290	209	140	634	516	413	321	242	174	117	545	444	354	276	208	150	100
3∅ 336.4 ACSR (18/1)	709	578	461	360	271	195	131	599	488	390	304	229	165	110	519	422	337	263	198	143	96
3∅ 477.0 ACSR (18/1)	663	540	431	336	253	182	122	566	461	368	287	216	156	104	493	402	321	250	189	136	91

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	869	697	545	412	297	198	114	706	567	443	335	241	161	92	595	477	373	282	203	135	78
3∅ 1/O ACSR (6/1)	791	634	496	375	270	180	103	654	524	410	310	223	149	85	557	447	350	264	190	127	73
3∅ 4/O ACSR (6/1)	715	574	449	339	244	163	93	601	482	377	285	205	137	79	519	416	325	246	177	118	68
3∅ 336.4 ACSR (18/1)	668	536	419	317	228	152	87	568	455	356	269	194	129	74	493	396	310	234	169	112	65
3∅ 477.0 ACSR (18/1)	624	501	392	296	213	142	82	536	430	336	254	183	122	70	469	376	294	223	160	107	61

NESC Extreme Wind (90 mph) - Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,281	2,716	2,219	1,784	1,409	1,088	818	774	641	523	421	332	257	193	439	363	297	238	188	145	109
1∅ 1/O ACSR (6/1)	2,109	1,745	1,424	1,145	903	696	522	682	564	461	370	292	225	169	407	337	275	221	174	134	101
1∅ 4/O ACSR (6/1)	1,491	1,234	1,007	809	638	492	369	601	498	406	326	257	198	149	377	312	254	204	161	124	93
1∅ 336.4 ACSR (18/1)	1,227	1,015	829	666	525	405	304	553	458	374	300	237	183	137	357	296	241	194	153	118	88
1∅ 477.0 ACSR (18/1)	1,031	853	696	560	441	340	255	510	422	344	277	218	168	126	339	280	229	184	145	112	84
3∅ 4 ACSR (7/1)	1,605	1,328	1,084	871	687	530	398	619	512	418	336	265	204	153	384	317	259	208	164	127	95
3∅ 1/O ACSR (6/1)	1,037	858	700	563	444	342	257	511	423	345	277	219	169	127	339	281	229	184	145	112	84
3∅ 4/O ACSR (6/1)	733	606	495	398	314	242	182	424	351	287	230	182	140	105	299	247	202	162	128	99	74
3∅ 336.4 ACSR (18/1)	603	499	407	327	258	199	149	377	312	255	205	162	125	93	275	227	185	149	118	91	68
3∅ 477.0 ACSR (18/1)	507	419	342	275	217	167	126	337	279	228	183	144	111	84	253	209	171	137	108	83	63

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,172	2,608	2,111	1,678	1,303	983	714	783	644	521	414	322	243	176	447	367	297	236	184	139	101
1∅ 1/O ACSR (6/1)	2,048	1,684	1,363	1,083	841	635	461	690	567	459	365	283	214	155	415	341	276	219	170	129	93
1∅ 4/O ACSR (6/1)	1,448	1,190	964	766	595	449	326	605	498	403	320	249	188	136	383	315	255	202	157	119	86
1∅ 336.4 ACSR (18/1)	1,192	980	793	630	490	369	268	555	457	370	294	228	172	125	362	298	241	192	149	112	82
1∅ 477.0 ACSR (18/1)	1,001	823	667	530	411	310	226	510	420	340	270	210	158	115	342	281	228	181	141	106	77
3∅ 4 ACSR (7/1)	1,559	1,282	1,038	825	640	483	351	624	513	415	330	256	193	141	390	321	260	206	160	121	88
3∅ 1/O ACSR (6/1)	1,007	828	670	532	414	312	227	512	421	341	271	210	159	115	343	282	228	181	141	106	77
3∅ 4/O ACSR (6/1)	712	585	474	376	292	221	160	423	347	281	224	174	131	95	301	247	200	159	123	93	68
3∅ 336.4 ACSR (18/1)	586	482	390	310	241	182	132	375	308	249	198	154	116	84	276	227	183	146	113	85	62
3∅ 477.0 ACSR (18/1)	492	405	328	260	202	153	111	334	275	222	177	137	104	75	253	208	168	134	104	78	57

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,972	2,408	1,912	1,478	1,103	784	515	769	623	495	382	285	203	133	442	358	284	220	164	116	76
1∅ 1/O ACSR (6/1)	1,919	1,555	1,234	954	712	506	332	673	546	433	335	250	178	117	408	331	263	203	152	108	71
1∅ 4/O ACSR (6/1)	1,357	1,099	873	675	504	358	235	588	476	378	292	218	155	102	375	304	241	187	139	99	65
1∅ 336.4 ACSR (18/1)	1,117	905	718	555	415	294	193	538	436	346	267	200	142	93	354	287	228	176	131	93	61
1∅ 477.0 ACSR (18/1)	938	760	604	467	348	247	162	493	399	317	245	183	130	85	334	271	215	166	124	88	58
3∅ 4 ACSR (7/1)	1,461	1,184	940	726	542	385	253	607	492	390	302	225	160	105	383	310	246	190	142	101	66
3∅ 1/O ACSR (6/1)	943	764	607	469	350	249	163	494	400	318	246	183	130	86	335	271	215	166	124	88	58
3∅ 4/O ACSR (6/1)	667	540	429	332	248	176	115	406	329	261	202	151	107	70	292	236	188	145	108	77	51
3∅ 336.4 ACSR (18/1)	549	445	353	273	204	145	95	359	291	231	179	133	95	62	267	216	172	133	99	70	46
3∅ 477.0 ACSR (18/1)	461	374	297	229	171	122	80	319	259	205	159	119	84	55	244	198	157	121	91	64	42

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,734	2,171	1,674	1,241	866	546	277	730	579	447	331	231	146	74	421	334	258	191	133	84	43
1∅ 1/O ACSR (6/1)	1,766	1,402	1,081	801	559	353	179	636	505	390	289	202	127	64	388	308	238	176	123	78	39
1∅ 4/O ACSR (6/1)	1,248	991	764	566	395	249	126	554	440	339	251	175	111	56	356	282	218	161	113	71	36
1∅ 336.4 ACSR (18/1)	1,027	816	629	466	325	205	104	505	401	309	229	160	101	51	335	266	205	152	106	67	34
1∅ 477.0 ACSR (18/1)	863	685	529	392	273	172	87	462	367	283	210	146	92	47	316	251	193	143	100	63	32
3∅ 4 ACSR (7/1)	1,344	1,067	823	610	426	268	136	572	454	350	259	181	114	58	363	288	222	165	115	73	37
3∅ 1/O ACSR (6/1)	868	689	531	394	275	173	88	464	368	284	210	147	93	47	316	251	194	143	100	63	32
3∅ 4/O ACSR (6/1)	614	487	376	278	194	123	62	380	301	232	172	120	76	38	275	218	168	125	87	55	28
3∅ 336.4 ACSR (18/1)	505	401	309	229	160	101	51	335	266	205	152	106	67	34	251	199	153	114	79	50	25
3∅ 477.0 ACSR (18/1)	424	337	260	193	134	85	43	297	236	182	135	94	59	30	229	182	140	104	73	46	23

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,466	1,189	945	731	547	390	258	587	476	378	293	219	156	103	367	297	236	183	137	98	65
3∅ 1/O ACSR (6/1)	946	768	610	472	353	252	167	481	390	310	240	180	128	85	322	262	208	161	120	86	57
3∅ 4/O ACSR (6/1)	669	543	431	334	250	178	118	397	322	256	198	148	106	70	283	229	182	141	106	75	50
3∅ 336.4 ACSR (18/1)	551	447	355	275	206	147	97	352	286	227	176	132	94	62	259	210	167	129	97	69	46
3∅ 477.0 ACSR (18/1)	463	375	298	231	173	123	81	314	255	202	157	117	84	55	238	193	153	119	89	63	42

NESC Extreme Wind (90 mph) - Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,171	894	650	437	253	96	-	486	371	270	181	105	40	-	307	234	170	115	66	25	-
3∅ 1/O ACSR (6/1)	756	577	420	282	163	62	-	396	302	220	148	86	32	-	268	205	149	100	58	22	-
3∅ 4/O ACSR (6/1)	535	408	297	199	115	44	-	325	248	181	121	70	27	-	234	179	130	87	50	19	-
3∅ 336.4 ACSR (18/1)	440	336	244	164	95	36	-	288	220	160	107	62	24	-	214	163	119	80	46	17	-
3∅ 477.0 ACSR (18/1)	370	282	205	138	80	30	-	256	195	142	96	55	21	-	196	149	109	73	42	16	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	823	546	302	89	-	-	-	350	232	128	38	-	-	-	222	148	82	24	-	-	-
3∅ 1/O ACSR (6/1)	531	353	195	57	-	-	-	284	188	104	31	-	-	-	194	128	71	21	-	-	-
3∅ 4/O ACSR (6/1)	376	249	138	41	-	-	-	232	154	85	25	-	-	-	168	112	62	18	-	-	-
3∅ 336.4 ACSR (18/1)	309	205	113	33	-	-	-	205	136	75	22	-	-	-	153	102	56	17	-	-	-
3∅ 477.0 ACSR (18/1)	260	172	95	28	-	-	-	182	121	67	20	-	-	-	140	93	51	15	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,389	1,112	868	655	471	313	181	614	492	384	290	208	139	80	395	316	246	186	134	89	51
3∅ 1/O ACSR (6/1)	897	718	560	423	304	202	117	494	396	309	233	168	112	64	341	273	213	161	116	77	45
3∅ 4/O ACSR (6/1)	634	508	396	299	215	143	83	402	322	251	190	136	91	52	295	236	184	139	100	67	38
3∅ 336.4 ACSR (18/1)	522	418	326	246	177	118	68	354	284	221	167	120	80	46	268	215	167	126	91	60	35
3∅ 477.0 ACSR (18/1)	439	351	274	207	149	99	57	314	251	196	148	106	71	41	244	195	153	115	83	55	32

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,338	1,061	817	604	420	262	130	575	456	351	260	180	113	56	366	290	224	165	115	72	36
3∅ 1/O ACSR (6/1)	864	685	527	390	271	169	84	465	369	284	210	146	91	45	319	253	194	144	100	62	31
3∅ 4/O ACSR (6/1)	611	484	373	276	192	120	59	380	302	232	172	119	75	37	276	219	169	125	87	54	27
3∅ 336.4 ACSR (18/1)	503	399	307	227	158	99	49	336	266	205	151	105	66	33	252	200	154	114	79	49	24
3∅ 477.0 ACSR (18/1)	422	335	258	191	132	83	41	298	236	182	134	93	58	29	230	182	140	104	72	45	22

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,229	952	708	495	310	153	21	541	419	311	218	137	67	9	347	268	200	139	88	43	6
3∅ 1/O ACSR (6/1)	793	615	457	319	200	99	14	436	337	251	175	110	54	7	300	232	173	121	76	37	5
3∅ 4/O ACSR (6/1)	561	434	323	226	142	70	10	355	275	204	143	90	44	6	259	201	149	104	66	32	4
3∅ 336.4 ACSR (18/1)	462	358	266	186	117	58	8	312	242	180	126	79	39	5	236	183	136	95	60	29	4
3∅ 477.0 ACSR (18/1)	388	300	223	156	98	48	7	277	214	159	111	70	35	5	215	167	124	87	54	27	4

NESC Extreme Wind (90 mph) - Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,968	4,123	3,378	2,726	2,162	1,680	1,273	1,172	972	797	643	510	396	300	664	551	452	364	289	225	170
1∅ 1/O ACSR (6/1)	3,208	2,663	2,181	1,761	1,396	1,085	822	1,037	861	705	569	452	351	266	619	514	421	340	269	209	159
1∅ 4/O ACSR (6/1)	2,268	1,882	1,542	1,245	987	767	581	915	759	622	502	398	309	234	573	475	390	314	249	194	147
1∅ 336.4 ACSR (18/1)	1,867	1,549	1,269	1,024	812	631	478	842	699	572	462	366	285	216	543	451	369	298	237	184	139
1∅ 477.0 ACSR (18/1)	1,569	1,302	1,067	861	683	530	402	775	643	527	425	337	262	199	515	427	350	283	224	174	132
3∅ 4 ACSR (7/1)	2,442	2,027	1,660	1,340	1,063	826	626	942	782	640	517	410	318	241	583	484	397	320	254	197	149
3∅ 1/O ACSR (6/1)	1,577	1,309	1,072	865	686	533	404	777	645	529	427	338	263	199	516	428	351	283	225	174	132
3∅ 4/O ACSR (6/1)	1,115	925	758	612	485	377	286	645	536	439	354	281	218	165	454	377	309	249	198	154	116
3∅ 336.4 ACSR (18/1)	918	761	624	504	399	310	235	574	476	390	315	250	194	147	418	347	284	229	182	141	107
3∅ 477.0 ACSR (18/1)	771	640	524	423	336	261	198	513	426	349	282	223	173	131	384	319	261	211	167	130	98

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,860	4,015	3,270	2,619	2,055	1,572	1,165	1,201	992	808	647	507	388	288	685	566	461	369	289	222	164
1∅ 1/O ACSR (6/1)	3,139	2,593	2,112	1,691	1,327	1,015	752	1,057	873	711	570	447	342	253	636	525	428	342	269	206	152
1∅ 4/O ACSR (6/1)	2,219	1,833	1,493	1,195	938	718	532	928	766	624	500	392	300	222	586	485	395	316	248	190	141
1∅ 336.4 ACSR (18/1)	1,826	1,509	1,229	984	772	591	438	851	703	573	459	360	275	204	555	458	373	299	235	179	133
1∅ 477.0 ACSR (18/1)	1,535	1,268	1,032	827	649	496	368	782	646	526	421	331	253	187	525	433	353	283	222	170	126
3∅ 4 ACSR (7/1)	2,389	1,974	1,607	1,287	1,010	773	573	956	790	643	515	404	309	229	598	494	402	322	253	193	143
3∅ 1/O ACSR (6/1)	1,543	1,274	1,038	831	652	499	370	784	648	528	422	331	254	188	526	434	354	283	222	170	126
3∅ 4/O ACSR (6/1)	1,091	901	734	588	461	353	261	648	535	436	349	274	209	155	461	380	310	248	195	149	110
3∅ 336.4 ACSR (18/1)	898	742	604	484	379	290	215	574	474	386	309	243	186	138	422	349	284	227	178	137	101
3∅ 477.0 ACSR (18/1)	754	623	507	406	319	244	181	512	423	345	276	216	166	123	388	320	261	209	164	125	93

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,615	3,770	3,025	2,373	1,809	1,327	920	1,194	976	783	614	468	343	238	686	560	450	353	269	197	137
1∅ 1/O ACSR (6/1)	2,980	2,435	1,953	1,533	1,168	857	594	1,046	854	685	538	410	301	208	634	518	416	326	249	182	126
1∅ 4/O ACSR (6/1)	2,107	1,721	1,381	1,083	826	606	420	913	746	598	469	358	262	182	583	476	382	300	228	168	116
1∅ 336.4 ACSR (18/1)	1,734	1,417	1,137	892	680	499	346	835	682	547	429	327	240	166	550	449	361	283	216	158	110
1∅ 477.0 ACSR (18/1)	1,457	1,190	955	749	571	419	290	765	625	501	393	300	220	152	519	424	340	267	203	149	103
3∅ 4 ACSR (7/1)	2,269	1,853	1,487	1,167	889	652	452	942	770	617	484	369	271	188	594	486	390	306	233	171	118
3∅ 1/O ACSR (6/1)	1,465	1,197	960	753	574	421	292	767	627	503	395	301	221	153	520	425	341	267	204	149	104
3∅ 4/O ACSR (6/1)	1,036	846	679	533	406	298	206	630	515	413	324	247	181	126	453	370	297	233	178	130	90
3∅ 336.4 ACSR (18/1)	852	696	559	438	334	245	170	557	455	365	287	219	160	111	414	338	271	213	162	119	83
3∅ 477.0 ACSR (18/1)	716	585	469	368	281	206	143	496	405	325	255	194	143	99	379	310	248	195	149	109	76

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,301	3,456	2,711	2,059	1,495	1,013	606	1,148	922	723	549	399	270	162	662	532	417	317	230	156	93
1∅ 1/O ACSR (6/1)	2,777	2,232	1,750	1,330	965	654	391	1,001	804	631	479	348	236	141	611	491	385	292	212	144	86
1∅ 4/O ACSR (6/1)	1,963	1,578	1,237	940	683	462	276	871	700	549	417	303	205	123	560	450	353	268	195	132	79
1∅ 336.4 ACSR (18/1)	1,616	1,299	1,019	774	562	380	228	795	639	501	381	276	187	112	527	424	332	252	183	124	74
1∅ 477.0 ACSR (18/1)	1,358	1,091	856	650	472	320	191	727	584	458	348	253	171	102	496	399	313	238	173	117	70
3∅ 4 ACSR (7/1)	2,114	1,699	1,332	1,012	735	498	298	899	723	567	431	313	212	127	571	459	360	273	199	134	80
3∅ 1/O ACSR (6/1)	1,365	1,097	860	654	475	321	192	729	586	460	349	253	172	103	497	400	314	238	173	117	70
3∅ 4/O ACSR (6/1)	965	775	608	462	335	227	136	597	480	376	286	208	141	84	432	347	272	207	150	102	61
3∅ 336.4 ACSR (18/1)	794	638	501	380	276	187	112	527	423	332	252	183	124	74	394	317	248	189	137	93	56
3∅ 477.0 ACSR (18/1)	667	536	421	320	232	157	94	468	376	295	224	163	110	66	360	289	227	172	125	85	51

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,283	1,868	1,501	1,181	904	667	467	914	748	601	473	362	267	187	571	467	376	295	226	167	117
3∅ 1/O ACSR (6/1)	1,474	1,206	969	763	584	430	301	749	613	493	388	297	219	153	502	411	330	260	199	147	103
3∅ 4/O ACSR (6/1)	1,042	853	685	539	413	304	213	619	506	407	320	245	181	126	440	360	289	228	174	129	90
3∅ 336.4 ACSR (18/1)	858	702	564	444	340	250	175	549	449	361	284	217	160	112	403	330	265	209	160	118	82
3∅ 477.0 ACSR (18/1)	721	590	474	373	285	210	147	489	400	322	253	194	143	100	370	303	244	192	147	108	76

NESC Extreme Wind (90 mph) - Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,922	1,506	1,140	820	542	305	105	798	625	473	340	225	127	44	504	395	299	215	142	80	28
3∅ 1/O ACSR (6/1)	1,241	973	736	529	350	197	68	650	509	386	277	183	103	36	440	345	261	188	124	70	24
3∅ 4/O ACSR (6/1)	877	688	520	374	248	139	48	534	419	317	228	151	85	29	384	301	228	164	108	61	21
3∅ 336.4 ACSR (18/1)	722	566	428	308	204	115	39	472	370	280	201	133	75	26	351	275	208	150	99	56	19
3∅ 477.0 ACSR (18/1)	607	476	360	259	171	96	33	420	329	249	179	119	67	23	321	252	191	137	91	51	18

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,458	1,043	677	356	79	-	-	620	444	288	152	34	-	-	394	282	183	96	21	-	-
3∅ 1/O ACSR (6/1)	942	673	437	230	51	-	-	503	360	233	123	27	-	-	343	245	159	84	19	-	-
3∅ 4/O ACSR (6/1)	666	476	309	163	36	-	-	412	294	191	101	22	-	-	298	213	138	73	16	-	-
3∅ 336.4 ACSR (18/1)	548	392	254	134	30	-	-	363	260	169	89	20	-	-	272	194	126	66	15	-	-
3∅ 477.0 ACSR (18/1)	460	329	214	112	25	-	-	323	231	150	79	17	-	-	248	178	115	61	13	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,174	1,759	1,392	1,072	795	558	357	962	778	616	474	352	247	158	617	499	395	304	226	158	102
3∅ 1/O ACSR (6/1)	1,404	1,136	899	692	513	360	231	774	626	496	382	283	198	127	534	432	342	263	195	137	88
3∅ 4/O ACSR (6/1)	992	803	636	489	363	255	163	630	510	403	311	230	162	104	461	373	296	228	169	118	76
3∅ 336.4 ACSR (18/1)	817	661	523	403	299	209	134	554	448	355	273	203	142	91	419	339	269	207	153	108	69
3∅ 477.0 ACSR (18/1)	686	555	440	338	251	176	113	491	397	314	242	179	126	81	382	309	245	188	140	98	63

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,108	1,693	1,326	1,006	729	492	292	906	728	570	433	313	211	125	577	463	363	275	200	135	80
3∅ 1/O ACSR (6/1)	1,361	1,093	856	650	471	317	188	733	589	461	350	254	171	101	502	403	316	240	174	117	69
3∅ 4/O ACSR (6/1)	962	773	605	459	333	224	133	599	481	377	286	207	140	83	435	350	274	208	151	102	60
3∅ 336.4 ACSR (18/1)	792	636	498	378	274	185	110	529	425	333	252	183	123	73	397	319	250	189	137	93	55
3∅ 477.0 ACSR (18/1)	666	534	419	318	230	155	92	469	377	295	224	162	109	65	362	291	228	173	125	84	50

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,959	1,543	1,177	857	579	342	142	862	679	518	377	255	151	63	552	435	332	242	163	97	40
3∅ 1/O ACSR (6/1)	1,265	997	760	553	374	221	92	694	547	417	304	205	121	50	478	377	287	209	142	84	35
3∅ 4/O ACSR (6/1)	894	704	537	391	264	156	65	566	446	340	247	167	99	41	414	326	249	181	122	72	30
3∅ 336.4 ACSR (18/1)	736	580	442	322	218	129	53	498	392	299	218	147	87	36	376	296	226	165	111	66	27
3∅ 477.0 ACSR (18/1)	618	487	372	270	183	108	45	441	348	265	193	130	77	32	343	270	206	150	101	60	25

NESC Extreme Wind (120 mph) - Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,037	2,488	2,006	1,587	1,227	922	668	716	587	473	374	289	218	158	406	333	268	212	164	123	89
1∅ 1/O ACSR (6/1)	1,945	1,591	1,281	1,012	780	584	421	629	515	414	327	252	189	136	375	307	247	195	150	113	81
1∅ 4/O ACSR (6/1)	1,375	1,125	906	715	552	413	298	555	454	365	288	222	167	120	347	284	229	181	139	104	75
1∅ 336.4 ACSR (18/1)	1,132	926	745	589	454	340	245	510	418	336	265	205	153	111	329	270	217	171	132	99	71
1∅ 477.0 ACSR (18/1)	951	778	626	495	382	286	206	470	385	310	244	189	141	102	312	255	206	162	125	94	68
3∅ 4 ACSR (7/1)	1,480	1,211	975	770	594	445	321	571	467	376	297	229	172	124	354	289	233	184	142	106	77
3∅ 1/O ACSR (6/1)	956	782	630	497	384	287	207	471	386	310	245	189	142	102	313	256	206	163	125	94	68
3∅ 4/O ACSR (6/1)	676	553	445	352	271	203	146	391	320	258	204	157	118	85	275	225	181	143	110	83	60
3∅ 336.4 ACSR (18/1)	556	455	366	289	223	167	120	348	285	229	181	140	105	75	253	207	167	132	102	76	55
3∅ 477.0 ACSR (18/1)	467	382	308	243	188	140	101	311	254	205	162	125	93	67	233	191	153	121	93	70	50

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,928	2,378	1,896	1,478	1,118	814	560	715	581	463	361	273	199	137	407	331	264	205	155	113	78
1∅ 1/O ACSR (6/1)	1,891	1,536	1,225	954	722	525	362	630	512	408	318	241	175	121	378	307	245	191	144	105	72
1∅ 4/O ACSR (6/1)	1,336	1,086	866	675	510	371	256	554	450	359	280	212	154	106	349	284	226	176	133	97	67
1∅ 336.4 ACSR (18/1)	1,100	894	713	555	420	306	210	509	413	329	257	194	141	97	331	269	214	167	126	92	63
1∅ 477.0 ACSR (18/1)	924	751	599	467	353	257	177	467	380	303	236	179	130	89	313	254	203	158	119	87	60
3∅ 4 ACSR (7/1)	1,439	1,169	932	726	549	400	275	571	464	370	288	218	159	109	356	289	231	180	136	99	68
3∅ 1/O ACSR (6/1)	929	755	602	469	355	258	178	469	381	304	237	179	130	90	313	255	203	158	120	87	60
3∅ 4/O ACSR (6/1)	657	533	425	331	251	183	126	388	315	251	196	148	108	74	275	223	178	139	105	76	53
3∅ 336.4 ACSR (18/1)	541	439	350	273	206	150	103	344	279	223	174	131	96	66	252	205	163	127	96	70	48
3∅ 477.0 ACSR (18/1)	454	369	294	229	173	126	87	307	249	199	155	117	85	59	232	188	150	117	88	64	44

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,727	2,177	1,695	1,277	917	613	359	697	557	434	327	235	157	92	400	319	249	187	134	90	53
1∅ 1/O ACSR (6/1)	1,761	1,406	1,095	824	592	396	232	612	488	380	286	206	137	81	370	296	230	173	124	83	49
1∅ 4/O ACSR (6/1)	1,245	994	774	583	419	280	164	535	427	332	250	180	120	70	340	272	212	159	115	76	45
1∅ 336.4 ACSR (18/1)	1,025	818	637	480	345	230	135	489	391	304	229	165	110	64	322	257	200	151	108	72	42
1∅ 477.0 ACSR (18/1)	861	687	535	403	290	193	113	449	358	279	210	151	101	59	303	242	189	142	102	68	40
3∅ 4 ACSR (7/1)	1,340	1,070	833	627	451	301	177	551	440	343	258	185	124	73	347	277	216	163	117	78	46
3∅ 1/O ACSR (6/1)	865	691	538	405	291	194	114	450	359	280	211	151	101	59	304	243	189	142	102	68	40
3∅ 4/O ACSR (6/1)	612	488	380	286	206	137	81	370	296	230	173	124	83	49	265	212	165	124	89	60	35
3∅ 336.4 ACSR (18/1)	503	402	313	236	169	113	66	328	262	204	153	110	74	43	243	194	151	114	82	55	32
3∅ 477.0 ACSR (18/1)	423	338	263	198	142	95	56	291	233	181	136	98	65	38	222	178	138	104	75	50	29

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,487	1,937	1,455	1,037	677	373	119	656	511	384	273	179	98	31	378	294	221	158	103	57	18
1∅ 1/O ACSR (6/1)	1,606	1,251	940	669	437	241	77	573	446	335	239	156	86	27	349	272	204	145	95	52	17
1∅ 4/O ACSR (6/1)	1,135	884	664	473	309	170	54	499	389	292	208	136	75	24	320	249	187	133	87	48	15
1∅ 336.4 ACSR (18/1)	934	728	547	389	254	140	45	456	355	267	190	124	68	22	302	235	177	126	82	45	14
1∅ 477.0 ACSR (18/1)	785	612	459	327	214	118	38	417	325	244	174	114	63	20	284	221	166	118	77	43	14
3∅ 4 ACSR (7/1)	1,222	952	715	509	333	183	59	515	401	302	215	140	77	25	326	254	191	136	89	49	16
3∅ 1/O ACSR (6/1)	789	615	462	329	215	118	38	418	326	245	174	114	63	20	285	222	167	119	78	43	14
3∅ 4/O ACSR (6/1)	558	435	326	233	152	84	27	343	267	201	143	93	51	16	248	193	145	103	67	37	12
3∅ 336.4 ACSR (18/1)	459	358	269	191	125	69	22	303	236	177	126	83	45	15	226	176	132	94	62	34	11
3∅ 477.0 ACSR (18/1)	386	301	226	161	105	58	18	269	210	158	112	73	40	13	207	161	121	86	56	31	10

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,345	1,075	838	633	456	306	182	534	426	333	251	181	122	72	333	266	207	156	113	76	45
3∅ 1/O ACSR (6/1)	869	694	541	409	294	198	117	438	350	273	206	149	100	59	293	234	183	138	99	67	40
3∅ 4/O ACSR (6/1)	614	491	383	289	208	140	83	362	290	226	170	123	83	49	257	205	160	121	87	59	35
3∅ 336.4 ACSR (18/1)	505	404	315	238	171	115	68	322	257	200	151	109	73	43	236	189	147	111	80	54	32
3∅ 477.0 ACSR (18/1)	425	339	265	200	144	97	57	287	229	179	135	97	65	39	217	173	135	102	73	49	29

NESC Extreme Wind (120 mph) - Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,049	779	542	336	160	10	-	432	321	223	138	66	4	-	272	202	140	87	41	3	-
3∅ 1/O ACSR (6/1)	677	503	350	217	103	6	-	352	262	182	113	54	3	-	238	177	123	76	36	2	-
3∅ 4/O ACSR (6/1)	479	356	247	153	73	5	-	290	215	150	93	44	3	-	208	154	107	67	32	2	-
3∅ 336.4 ACSR (18/1)	394	293	204	126	60	4	-	256	190	132	82	39	2	-	190	141	98	61	29	2	-
3∅ 477.0 ACSR (18/1)	331	246	171	106	50	3	-	228	169	118	73	35	2	-	174	129	90	56	26	2	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	697	427	190	-	-	-	-	294	180	80	-	-	-	-	186	114	51	-	-	-	-
3∅ 1/O ACSR (6/1)	450	276	123	-	-	-	-	239	146	65	-	-	-	-	162	100	44	-	-	-	-
3∅ 4/O ACSR (6/1)	318	195	87	-	-	-	-	196	120	53	-	-	-	-	141	87	39	-	-	-	-
3∅ 336.4 ACSR (18/1)	262	160	71	-	-	-	-	173	106	47	-	-	-	-	129	79	35	-	-	-	-
3∅ 477.0 ACSR (18/1)	220	135	60	-	-	-	-	154	94	42	-	-	-	-	118	72	32	-	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,267	997	761	555	378	229	104	556	438	334	243	166	100	46	356	280	214	156	106	64	29
3∅ 1/O ACSR (6/1)	818	644	491	358	244	148	67	448	353	269	196	134	81	37	309	243	185	135	92	56	25
3∅ 4/O ACSR (6/1)	579	455	347	253	173	104	47	365	287	219	160	109	66	30	267	210	160	117	80	48	22
3∅ 336.4 ACSR (18/1)	476	375	286	208	142	86	39	322	253	193	141	96	58	26	243	191	146	106	72	44	20
3∅ 477.0 ACSR (18/1)	400	315	240	175	119	72	33	285	224	171	125	85	51	23	221	174	133	97	66	40	18

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,216	946	709	503	327	177	53	518	403	302	215	139	75	22	329	256	192	136	88	48	14
3∅ 1/O ACSR (6/1)	785	611	458	325	211	114	34	420	327	245	174	113	61	18	287	223	167	119	77	42	12
3∅ 4/O ACSR (6/1)	555	432	324	230	149	81	24	344	267	200	142	92	50	15	249	194	145	103	67	36	11
3∅ 336.4 ACSR (18/1)	457	355	266	189	123	67	20	303	236	177	126	82	44	13	227	177	132	94	61	33	10
3∅ 477.0 ACSR (18/1)	384	299	224	159	103	56	17	269	210	157	112	72	39	12	208	161	121	86	56	30	9

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,105	835	599	393	216	67	-	482	364	261	171	94	29	-	308	233	167	110	60	19	-
3∅ 1/O ACSR (6/1)	714	539	387	254	140	43	-	389	294	211	138	76	23	-	267	202	145	95	52	16	-
3∅ 4/O ACSR (6/1)	505	381	273	179	99	30	-	317	240	172	113	62	19	-	232	175	125	82	45	14	-
3∅ 336.4 ACSR (18/1)	415	314	225	148	81	25	-	280	211	151	99	55	17	-	211	159	114	75	41	13	-
3∅ 477.0 ACSR (18/1)	349	264	189	124	68	21	-	248	187	134	88	48	15	-	192	145	104	68	38	12	-

NESC Extreme Wind (120 mph) - Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,693	3,863	3,134	2,499	1,952	1,487	1,097	1,094	900	730	582	455	346	256	619	510	413	330	257	196	145
1∅ 1/O ACSR (6/1)	3,030	2,495	2,024	1,614	1,260	960	709	970	798	648	516	403	307	227	577	475	385	307	240	183	135
1∅ 4/O ACSR (6/1)	2,142	1,763	1,431	1,141	891	679	501	856	705	572	456	356	271	200	535	440	357	285	223	169	125
1∅ 336.4 ACSR (18/1)	1,763	1,452	1,178	939	733	559	412	788	649	527	420	328	250	184	508	418	339	270	211	161	119
1∅ 477.0 ACSR (18/1)	1,482	1,220	990	789	616	469	346	727	598	485	387	302	230	170	481	396	321	256	200	153	113
3∅ 4 ACSR (7/1)	2,306	1,898	1,540	1,228	959	731	539	881	725	588	469	367	279	206	545	448	364	290	227	173	127
3∅ 1/O ACSR (6/1)	1,489	1,226	994	793	619	472	348	728	600	486	388	303	231	170	482	397	322	257	201	153	113
3∅ 4/O ACSR (6/1)	1,053	867	703	561	438	334	246	606	499	404	323	252	192	142	425	350	284	226	177	135	99
3∅ 336.4 ACSR (18/1)	866	713	579	461	360	275	203	539	444	360	287	224	171	126	391	322	261	208	163	124	91
3∅ 477.0 ACSR (18/1)	728	599	486	388	303	231	170	482	397	322	257	200	153	113	360	297	241	192	150	114	84

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,584	3,755	3,026	2,391	1,844	1,378	989	1,119	917	739	584	450	337	241	637	522	421	332	256	192	137
1∅ 1/O ACSR (6/1)	2,960	2,425	1,954	1,544	1,190	890	639	987	808	651	515	397	297	213	592	485	391	309	238	178	128
1∅ 4/O ACSR (6/1)	2,093	1,714	1,381	1,091	842	629	451	867	710	572	452	349	261	187	547	448	361	285	220	164	118
1∅ 336.4 ACSR (18/1)	1,722	1,411	1,137	898	693	518	372	796	652	526	415	320	239	172	518	424	342	270	208	156	112
1∅ 477.0 ACSR (18/1)	1,447	1,185	955	755	582	435	312	732	600	483	382	294	220	158	490	401	323	255	197	147	106
3∅ 4 ACSR (7/1)	2,253	1,845	1,487	1,175	906	677	486	893	732	590	466	359	269	193	557	456	368	291	224	168	120
3∅ 1/O ACSR (6/1)	1,455	1,191	960	759	585	437	314	734	601	484	383	295	221	158	491	402	324	256	197	148	106
3∅ 4/O ACSR (6/1)	1,028	842	679	536	414	309	222	607	497	401	316	244	182	131	430	353	284	224	173	129	93
3∅ 336.4 ACSR (18/1)	846	693	559	441	340	254	183	539	441	355	281	217	162	116	395	323	261	206	159	119	85
3∅ 477.0 ACSR (18/1)	711	583	469	371	286	214	153	480	394	317	251	193	144	104	363	297	239	189	146	109	78

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,337	3,508	2,779	2,144	1,596	1,131	742	1,109	897	711	548	408	289	190	636	514	407	314	234	166	109
1∅ 1/O ACSR (6/1)	2,801	2,265	1,794	1,384	1,031	730	479	973	787	623	481	358	254	166	589	476	377	291	217	154	101
1∅ 4/O ACSR (6/1)	1,980	1,601	1,268	978	729	516	339	850	688	545	420	313	222	145	541	438	347	268	199	141	93
1∅ 336.4 ACSR (18/1)	1,630	1,318	1,044	805	600	425	279	779	630	499	385	287	203	133	511	414	328	253	188	133	87
1∅ 477.0 ACSR (18/1)	1,369	1,107	877	677	504	357	234	714	577	457	353	263	186	122	483	390	309	239	178	126	83
3∅ 4 ACSR (7/1)	2,131	1,724	1,365	1,053	784	556	364	877	709	562	434	323	229	150	552	447	354	273	203	144	94
3∅ 1/O ACSR (6/1)	1,376	1,113	882	680	507	359	235	716	579	458	354	263	187	122	483	391	310	239	178	126	83
3∅ 4/O ACSR (6/1)	973	787	623	481	358	254	166	589	476	377	291	217	154	101	422	341	270	209	155	110	72
3∅ 336.4 ACSR (18/1)	801	648	513	396	295	209	137	521	421	334	257	192	136	89	386	312	247	191	142	101	66
3∅ 477.0 ACSR (18/1)	673	544	431	333	248	176	115	464	375	297	229	171	121	79	354	286	227	175	130	92	60

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,019	3,190	2,461	1,826	1,278	813	424	1,060	841	649	482	337	215	112	611	485	374	277	194	124	64
1∅ 1/O ACSR (6/1)	2,595	2,060	1,589	1,179	826	525	274	926	735	567	421	295	187	98	564	447	345	256	179	114	59
1∅ 4/O ACSR (6/1)	1,835	1,456	1,123	833	584	371	193	807	640	494	366	257	163	85	517	410	317	235	164	105	55
1∅ 336.4 ACSR (18/1)	1,510	1,198	925	686	480	306	159	737	585	451	335	234	149	78	488	387	299	221	155	99	51
1∅ 477.0 ACSR (18/1)	1,269	1,007	777	576	404	257	134	675	535	413	306	215	136	71	459	365	281	209	146	93	48
3∅ 4 ACSR (7/1)	1,975	1,567	1,209	897	628	400	208	833	661	510	378	265	169	88	528	419	323	240	168	107	56
3∅ 1/O ACSR (6/1)	1,275	1,012	781	579	406	258	134	676	537	414	307	215	137	71	460	365	282	209	146	93	49
3∅ 4/O ACSR (6/1)	902	715	552	409	287	182	95	554	440	339	252	176	112	58	400	318	245	182	127	81	42
3∅ 336.4 ACSR (18/1)	742	589	454	337	236	150	78	490	389	300	222	156	99	52	365	290	224	166	116	74	39
3∅ 477.0 ACSR (18/1)	624	495	382	283	198	126	66	435	345	266	198	138	88	46	334	265	205	152	106	68	35

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,146	1,739	1,380	1,068	799	571	379	851	690	547	424	317	226	150	531	430	341	264	198	141	94
3∅ 1/O ACSR (6/1)	1,386	1,123	891	690	516	369	245	699	566	450	348	260	186	124	467	379	301	233	174	124	83
3∅ 4/O ACSR (6/1)	980	794	630	488	365	261	173	578	468	372	288	215	154	102	410	332	264	204	153	109	72
3∅ 336.4 ACSR (18/1)	806	653	519	401	300	214	143	513	416	330	255	191	136	91	376	305	242	187	140	100	67
3∅ 477.0 ACSR (18/1)	678	549	436	337	252	180	120	458	371	294	228	170	122	81	346	280	222	172	129	92	61

NESC Extreme Wind (120 mph) - Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,782	1,374	1,016	704	435	206	15	733	566	418	290	179	85	6	462	356	263	182	113	53	4
3∅ 1/O ACSR (6/1)	1,151	887	656	455	281	133	10	598	461	341	236	146	69	5	404	312	230	160	99	47	3
3∅ 4/O ACSR (6/1)	813	627	464	321	199	94	7	492	380	281	194	120	57	4	353	272	201	139	86	41	3
3∅ 336.4 ACSR (18/1)	669	516	382	264	163	78	6	436	336	248	172	106	50	4	323	249	184	127	79	37	3
3∅ 477.0 ACSR (18/1)	563	434	321	222	137	65	5	388	299	221	153	95	45	3	296	228	169	117	72	34	2

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,313	905	547	235	-	-	-	554	382	231	99	-	-	-	351	242	146	63	-	-	-
3∅ 1/O ACSR (6/1)	848	585	353	152	-	-	-	450	310	187	81	-	-	-	306	211	128	55	-	-	-
3∅ 4/O ACSR (6/1)	599	413	250	107	-	-	-	369	254	154	66	-	-	-	266	184	111	48	-	-	-
3∅ 336.4 ACSR (18/1)	493	340	206	88	-	-	-	326	225	136	58	-	-	-	243	168	101	44	-	-	-
3∅ 477.0 ACSR (18/1)	415	286	173	74	-	-	-	289	199	121	52	-	-	-	222	153	93	40	-	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,035	1,628	1,270	958	689	460	269	893	714	557	420	302	202	118	572	457	357	269	194	129	76
3∅ 1/O ACSR (6/1)	1,314	1,051	820	618	445	297	174	720	576	449	339	244	163	95	495	396	309	233	168	112	65
3∅ 4/O ACSR (6/1)	929	743	580	437	314	210	123	587	469	366	276	198	133	77	429	343	267	202	145	97	57
3∅ 336.4 ACSR (18/1)	765	612	477	360	259	173	101	516	413	322	243	175	117	68	390	312	243	183	132	88	51
3∅ 477.0 ACSR (18/1)	643	514	401	302	217	145	85	458	366	286	215	155	103	60	355	284	222	167	120	80	47

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,969	1,561	1,203	891	622	394	202	839	665	513	380	265	168	86	533	423	326	241	169	107	55
3∅ 1/O ACSR (6/1)	1,271	1,008	777	575	402	254	131	680	539	416	308	215	136	70	464	368	284	210	147	93	48
3∅ 4/O ACSR (6/1)	899	713	549	407	284	180	92	557	441	340	252	176	111	57	403	320	246	182	127	81	41
3∅ 336.4 ACSR (18/1)	740	587	452	335	234	148	76	491	390	300	222	155	98	50	368	292	225	166	116	74	38
3∅ 477.0 ACSR (18/1)	622	493	380	281	196	124	64	436	346	267	197	138	87	45	336	266	205	152	106	67	35

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,818	1,410	1,052	740	471	242	51	793	615	459	323	205	106	22	507	393	293	206	131	68	14
3∅ 1/O ACSR (6/1)	1,174	910	679	478	304	156	33	640	496	370	260	166	85	18	440	341	254	179	114	59	12
3∅ 4/O ACSR (6/1)	830	644	480	338	215	111	23	522	405	302	212	135	70	15	381	295	220	155	99	51	11
3∅ 336.4 ACSR (18/1)	683	530	395	278	177	91	19	460	357	266	187	119	61	13	346	269	200	141	90	46	10
3∅ 477.0 ACSR (18/1)	574	445	332	234	149	76	16	408	316	236	166	106	54	11	316	245	183	129	82	42	9

NESC Extreme Wind (150 mph) - Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,724	2,195	1,733	1,334	995	709	475	642	518	409	315	235	167	112	364	293	232	178	133	95	64
1∅ 1/O ACSR (6/1)	1,733	1,393	1,097	841	623	441	291	560	451	355	272	201	142	94	334	269	212	162	120	85	56
1∅ 4/O ACSR (6/1)	1,225	985	775	594	440	311	206	494	397	313	240	178	126	83	310	249	196	150	111	79	52
1∅ 336.4 ACSR (18/1)	1,009	811	638	489	362	256	169	455	366	288	221	163	116	76	294	236	186	142	106	75	49
1∅ 477.0 ACSR (18/1)	847	681	536	411	305	215	142	419	337	265	203	151	106	70	278	224	176	135	100	71	47
3∅ 4 ACSR (7/1)	1,319	1,061	835	640	474	335	221	509	409	322	247	183	129	85	315	253	199	153	113	80	53
3∅ 1/O ACSR (6/1)	852	685	539	413	306	217	143	420	338	266	204	151	107	70	279	224	176	135	100	71	47
3∅ 4/O ACSR (6/1)	602	484	381	292	216	153	101	349	280	221	169	125	89	59	245	197	155	119	88	62	41
3∅ 336.4 ACSR (18/1)	496	398	314	240	178	126	83	310	249	196	150	111	79	52	226	181	143	109	81	57	38
3∅ 477.0 ACSR (18/1)	417	335	264	202	150	106	70	277	223	175	134	100	70	47	208	167	131	101	75	53	35

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,589	2,063	1,604	1,207	870	587	356	640	510	396	298	215	145	88	365	291	226	170	123	83	50
1∅ 1/O ACSR (6/1)	1,672	1,332	1,035	780	562	379	230	563	449	349	263	189	128	77	339	270	210	158	114	77	47
1∅ 4/O ACSR (6/1)	1,182	942	732	551	397	268	162	494	394	306	230	166	112	68	312	249	193	146	105	71	43
1∅ 336.4 ACSR (18/1)	973	775	603	454	327	221	134	453	361	281	211	152	103	62	296	236	183	138	99	67	41
1∅ 477.0 ACSR (18/1)	818	651	506	381	275	185	112	417	332	258	194	140	95	57	280	223	173	130	94	63	38
3∅ 4 ACSR (7/1)	1,273	1,014	788	593	428	289	175	509	406	315	238	171	116	70	318	254	197	148	107	72	44
3∅ 1/O ACSR (6/1)	822	655	509	383	276	186	113	418	333	259	195	140	95	57	280	223	173	131	94	64	38
3∅ 4/O ACSR (6/1)	581	463	360	271	195	132	80	345	275	214	161	116	78	47	245	195	152	114	82	56	34
3∅ 336.4 ACSR (18/1)	478	381	296	223	161	108	66	306	244	189	143	103	69	42	225	179	139	105	76	51	31
3∅ 477.0 ACSR (18/1)	402	320	249	187	135	91	55	273	217	169	127	92	62	37	206	164	128	96	69	47	28

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,390	1,863	1,404	1,008	670	388	156	618	482	363	261	173	100	40	355	277	209	150	100	58	23
1∅ 1/O ACSR (6/1)	1,543	1,203	907	651	433	250	101	541	422	318	228	152	88	35	328	256	193	138	92	53	21
1∅ 4/O ACSR (6/1)	1,091	851	641	460	306	177	71	473	369	278	199	133	77	31	302	235	177	127	85	49	20
1∅ 336.4 ACSR (18/1)	898	700	527	379	252	146	59	432	337	254	182	121	70	28	285	222	167	120	80	46	19
1∅ 477.0 ACSR (18/1)	754	588	443	318	212	122	49	396	309	233	167	111	64	26	269	209	158	113	75	44	18
3∅ 4 ACSR (7/1)	1,175	916	690	495	329	191	77	488	380	287	206	137	79	32	308	240	181	130	86	50	20
3∅ 1/O ACSR (6/1)	758	591	446	320	213	123	50	397	310	233	168	111	64	26	269	210	158	113	75	44	18
3∅ 4/O ACSR (6/1)	536	418	315	226	150	87	35	326	254	192	138	92	53	21	235	183	138	99	66	38	15
3∅ 336.4 ACSR (18/1)	441	344	259	186	124	72	29	289	225	170	122	81	47	19	214	167	126	90	60	35	14
3∅ 477.0 ACSR (18/1)	371	289	218	156	104	60	24	257	200	151	108	72	42	17	196	153	115	83	55	32	13

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,152	1,626	1,166	770	433	150	-	574	434	311	205	115	40	-	331	250	180	119	67	23	-
1∅ 1/O ACSR (6/1)	1,390	1,050	753	497	279	97	-	501	378	271	179	101	35	-	306	231	166	109	61	21	-
1∅ 4/O ACSR (6/1)	982	742	532	352	198	69	-	436	329	236	156	88	30	-	280	212	152	100	56	20	-
1∅ 336.4 ACSR (18/1)	809	611	438	289	163	56	-	398	301	216	142	80	28	-	264	199	143	94	53	18	-
1∅ 477.0 ACSR (18/1)	679	513	368	243	137	47	-	364	275	197	130	73	25	-	248	188	135	89	50	17	-
3∅ 4 ACSR (7/1)	1,058	799	573	379	213	74	-	450	340	244	161	90	31	-	286	216	155	102	57	20	-
3∅ 1/O ACSR (6/1)	683	516	370	244	137	48	-	365	276	198	131	73	25	-	249	188	135	89	50	17	-
3∅ 4/O ACSR (6/1)	483	365	262	173	97	34	-	299	226	162	107	60	21	-	216	163	117	77	43	15	-
3∅ 336.4 ACSR (18/1)	397	300	215	142	80	28	-	264	199	143	94	53	18	-	197	149	107	71	40	14	-
3∅ 477.0 ACSR (18/1)	334	252	181	120	67	23	-	234	177	127	84	47	16	-	180	136	98	65	36	13	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,180	921	695	500	334	196	82	472	369	278	200	134	78	33	295	230	174	125	84	49	20
3∅ 1/O ACSR (6/1)	762	595	449	323	216	126	53	387	302	228	164	110	64	27	260	203	153	110	74	43	18
3∅ 4/O ACSR (6/1)	538	420	317	228	153	89	37	320	250	188	136	91	53	22	227	178	134	96	64	38	16
3∅ 336.4 ACSR (18/1)	443	346	261	188	126	73	31	284	221	167	120	80	47	20	208	163	123	88	59	35	14
3∅ 477.0 ACSR (18/1)	372	291	219	158	106	62	26	253	197	149	107	72	42	18	191	149	113	81	54	32	13

NESC Extreme Wind (150 mph) - Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	885	626	401	206	40	-	-	368	260	166	85	17	-	-	232	164	105	54	10	-	-
3∅ 1/O ACSR (6/1)	572	404	259	133	26	-	-	299	212	135	70	14	-	-	203	143	92	47	9	-	-
3∅ 4/O ACSR (6/1)	404	286	183	94	18	-	-	246	174	111	57	11	-	-	177	125	80	41	8	-	-
3∅ 336.4 ACSR (18/1)	333	235	150	77	15	-	-	217	154	98	51	10	-	-	162	114	73	38	7	-	-
3∅ 477.0 ACSR (18/1)	279	198	126	65	13	-	-	193	137	88	45	9	-	-	148	105	67	34	7	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	537	278	52	-	-	-	-	228	118	22	-	-	-	-	145	75	14	-	-	-	-
3∅ 1/O ACSR (6/1)	347	180	34	-	-	-	-	185	96	18	-	-	-	-	126	65	12	-	-	-	-
3∅ 4/O ACSR (6/1)	245	127	24	-	-	-	-	152	79	15	-	-	-	-	110	57	11	-	-	-	-
3∅ 336.4 ACSR (18/1)	202	105	20	-	-	-	-	134	69	13	-	-	-	-	100	52	10	-	-	-	-
3∅ 477.0 ACSR (18/1)	170	88	17	-	-	-	-	119	62	12	-	-	-	-	91	47	9	-	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,103	844	618	423	258	119	5	488	373	274	187	114	53	2	313	240	176	120	73	34	-
3∅ 1/O ACSR (6/1)	712	545	399	273	166	77	3	393	300	220	151	92	42	-	271	207	152	104	63	29	-
3∅ 4/O ACSR (6/1)	503	385	282	193	118	54	2	320	245	179	123	75	34	-	234	179	131	90	55	25	-
3∅ 336.4 ACSR (18/1)	414	317	232	159	97	45	2	281	215	158	108	66	30	-	213	163	119	82	50	23	-
3∅ 477.0 ACSR (18/1)	348	266	195	134	81	38	2	249	191	140	96	58	27	-	194	148	109	74	45	21	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,052	793	567	372	207	68	-	452	341	244	160	89	29	-	288	217	155	102	57	19	-
3∅ 1/O ACSR (6/1)	679	512	366	241	133	44	-	366	276	197	130	72	24	-	250	189	135	89	49	16	-
3∅ 4/O ACSR (6/1)	480	362	259	170	94	31	-	299	226	161	106	59	19	-	217	164	117	77	43	14	-
3∅ 336.4 ACSR (18/1)	395	298	213	140	78	25	-	264	199	142	93	52	17	-	198	149	107	70	39	13	-
3∅ 477.0 ACSR (18/1)	332	250	179	118	65	21	-	234	176	126	83	46	15	-	181	136	97	64	36	12	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	943	684	458	263	97	-	-	415	301	202	116	43	-	-	266	193	129	74	27	-	-
3∅ 1/O ACSR (6/1)	609	442	296	170	63	-	-	334	242	162	93	35	-	-	230	167	112	64	24	-	-
3∅ 4/O ACSR (6/1)	430	312	209	120	45	-	-	272	197	132	76	28	-	-	199	144	97	56	21	-	-
3∅ 336.4 ACSR (18/1)	354	257	172	99	37	-	-	240	174	116	67	25	-	-	181	131	88	51	19	-	-
3∅ 477.0 ACSR (18/1)	298	216	145	83	31	-	-	212	154	103	59	22	-	-	165	120	80	46	17	-	-

NESC Extreme Wind (150 mph) - Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,307	3,504	2,801	2,192	1,670	1,230	865	1,016	826	661	517	394	290	204	576	468	374	293	223	164	116
1∅ 1/O ACSR (6/1)	2,781	2,263	1,809	1,415	1,079	794	559	899	732	585	458	349	257	181	536	436	349	273	208	153	108
1∅ 4/O ACSR (6/1)	1,966	1,600	1,279	1,001	762	562	395	793	645	516	404	308	226	159	497	404	323	253	193	142	100
1∅ 336.4 ACSR (18/1)	1,618	1,317	1,052	824	628	462	325	730	594	475	371	283	208	147	471	383	306	240	183	135	95
1∅ 477.0 ACSR (18/1)	1,360	1,106	884	692	527	388	273	672	547	437	342	261	192	135	446	363	290	227	173	127	90
3∅ 4 ACSR (7/1)	2,117	1,722	1,377	1,077	821	605	425	816	664	531	416	317	233	164	506	411	329	257	196	144	102
3∅ 1/O ACSR (6/1)	1,367	1,112	889	696	530	390	275	674	548	438	343	261	192	135	447	364	291	228	173	128	90
3∅ 4/O ACSR (6/1)	966	786	629	492	375	276	194	560	455	364	285	217	160	112	394	320	256	200	153	112	79
3∅ 336.4 ACSR (18/1)	795	647	517	405	308	227	160	498	405	324	253	193	142	100	362	295	235	184	140	103	73
3∅ 477.0 ACSR (18/1)	668	544	435	340	259	191	134	445	362	289	226	172	127	89	333	271	217	170	129	95	67

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,199	3,396	2,693	2,084	1,562	1,122	757	1,037	839	665	515	386	277	187	592	479	380	294	220	158	107
1∅ 1/O ACSR (6/1)	2,711	2,193	1,739	1,346	1,009	725	489	913	739	586	453	340	244	165	549	444	352	273	204	147	99
1∅ 4/O ACSR (6/1)	1,917	1,550	1,229	951	713	512	346	801	648	514	398	298	214	145	507	410	325	251	189	135	91
1∅ 336.4 ACSR (18/1)	1,578	1,276	1,012	783	587	422	285	735	595	472	365	274	197	133	479	388	308	238	178	128	86
1∅ 477.0 ACSR (18/1)	1,326	1,072	850	658	493	354	239	676	546	433	335	251	181	122	453	367	291	225	169	121	82
3∅ 4 ACSR (7/1)	2,064	1,669	1,324	1,024	768	552	372	826	668	530	410	307	221	149	516	418	331	256	192	138	93
3∅ 1/O ACSR (6/1)	1,333	1,078	855	661	496	356	240	677	548	434	336	252	181	122	454	367	291	225	169	121	82
3∅ 4/O ACSR (6/1)	942	762	604	468	351	252	170	559	453	359	278	208	150	101	398	322	255	197	148	106	72
3∅ 336.4 ACSR (18/1)	775	627	497	385	289	207	140	496	401	318	246	185	133	90	365	295	234	181	136	97	66
3∅ 477.0 ACSR (18/1)	652	527	418	323	242	174	118	442	358	284	220	165	118	80	335	271	215	166	125	89	60

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,954	3,151	2,448	1,839	1,317	877	512	1,023	815	633	476	341	227	133	588	468	364	273	196	130	76
1∅ 1/O ACSR (6/1)	2,553	2,035	1,581	1,187	851	566	331	896	714	555	417	298	199	116	543	433	336	253	181	121	70
1∅ 4/O ACSR (6/1)	1,805	1,438	1,118	839	601	400	234	782	623	484	364	261	173	101	499	398	309	232	166	111	65
1∅ 336.4 ACSR (18/1)	1,486	1,184	920	691	495	330	193	715	570	443	333	238	159	93	471	376	292	219	157	105	61
1∅ 477.0 ACSR (18/1)	1,248	995	773	581	416	277	162	655	522	406	305	218	145	85	444	354	275	207	148	99	58
3∅ 4 ACSR (7/1)	1,943	1,549	1,203	904	647	431	252	807	643	500	375	269	179	105	509	406	315	237	170	113	66
3∅ 1/O ACSR (6/1)	1,255	1,000	777	584	418	278	163	657	524	407	306	219	146	85	445	355	276	207	148	99	58
3∅ 4/O ACSR (6/1)	887	707	549	413	296	197	115	540	430	334	251	180	120	70	388	309	240	181	129	86	50
3∅ 336.4 ACSR (18/1)	730	582	452	340	243	162	95	478	381	296	222	159	106	62	355	283	220	165	118	79	46
3∅ 477.0 ACSR (18/1)	614	489	380	285	204	136	80	425	339	263	198	142	94	55	325	259	201	151	108	72	42

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,640	2,837	2,134	1,525	1,003	563	198	971	757	569	407	268	150	53	560	437	329	235	154	87	31
1∅ 1/O ACSR (6/1)	2,350	1,832	1,378	985	648	363	128	847	660	497	355	233	131	46	517	403	303	216	142	80	28
1∅ 4/O ACSR (6/1)	1,661	1,295	974	696	458	257	90	737	574	432	309	203	114	40	474	369	278	198	130	73	26
1∅ 336.4 ACSR (18/1)	1,367	1,066	802	573	377	211	74	673	524	394	282	185	104	37	446	348	262	187	123	69	24
1∅ 477.0 ACSR (18/1)	1,149	896	674	481	317	178	63	615	480	361	258	170	95	34	420	327	246	176	116	65	23
3∅ 4 ACSR (7/1)	1,789	1,394	1,049	749	493	277	97	761	593	446	319	210	118	41	483	377	283	202	133	75	26
3∅ 1/O ACSR (6/1)	1,155	900	677	484	318	179	63	617	481	362	258	170	95	34	421	328	247	176	116	65	23
3∅ 4/O ACSR (6/1)	817	637	479	342	225	126	44	505	394	296	212	139	78	28	366	285	214	153	101	57	20
3∅ 336.4 ACSR (18/1)	672	524	394	282	185	104	37	446	348	261	187	123	69	24	334	260	196	140	92	52	18
3∅ 477.0 ACSR (18/1)	565	440	331	237	156	87	31	396	309	232	166	109	61	22	305	238	179	128	84	47	17

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,958	1,563	1,218	918	662	446	266	784	626	487	368	265	178	107	490	391	305	230	166	111	67
3∅ 1/O ACSR (6/1)	1,264	1,009	786	593	427	288	172	643	513	400	301	217	146	87	431	344	268	202	146	98	59
3∅ 4/O ACSR (6/1)	894	714	556	419	302	203	122	531	424	330	249	179	121	72	377	301	235	177	128	86	51
3∅ 336.4 ACSR (18/1)	736	587	458	345	249	167	100	471	376	293	221	159	107	64	346	276	215	162	117	79	47
3∅ 477.0 ACSR (18/1)	618	494	384	290	209	141	84	420	335	261	197	142	95	57	318	254	198	149	107	72	43

NESC Extreme Wind (150 mph) - Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,596	1,202	856	557	300	84	-	663	499	356	231	125	35	-	418	315	224	146	79	22	-
3∅ 1/O ACSR (6/1)	1,031	776	553	360	194	54	-	540	406	290	188	102	28	-	366	275	196	128	69	19	-
3∅ 4/O ACSR (6/1)	729	549	391	254	137	38	-	444	334	238	155	83	23	-	319	240	171	111	60	17	-
3∅ 336.4 ACSR (18/1)	600	452	322	209	113	32	-	392	295	210	137	74	21	-	291	219	156	102	55	15	-
3∅ 477.0 ACSR (18/1)	504	379	270	176	95	27	-	349	263	187	122	66	18	-	267	201	143	93	50	14	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,133	738	393	94	-	-	-	482	314	167	40	-	-	-	306	200	106	25	-	-	-
3∅ 1/O ACSR (6/1)	732	477	254	60	-	-	-	391	255	136	32	-	-	-	267	174	92	22	-	-	-
3∅ 4/O ACSR (6/1)	517	337	179	43	-	-	-	320	209	111	26	-	-	-	232	151	80	19	-	-	-
3∅ 336.4 ACSR (18/1)	426	277	148	35	-	-	-	282	184	98	23	-	-	-	211	138	73	17	-	-	-
3∅ 477.0 ACSR (18/1)	358	233	124	30	-	-	-	251	163	87	21	-	-	-	193	126	67	16	-	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,849	1,454	1,109	809	553	336	157	818	643	490	358	245	149	70	525	413	315	230	157	96	45
3∅ 1/O ACSR (6/1)	1,194	939	716	523	357	217	102	658	518	395	288	197	120	56	454	357	272	199	136	83	39
3∅ 4/O ACSR (6/1)	844	664	506	369	252	154	72	536	421	321	234	160	97	46	392	309	235	172	117	71	33
3∅ 336.4 ACSR (18/1)	695	546	417	304	208	126	59	471	371	283	206	141	86	40	357	281	214	156	107	65	30
3∅ 477.0 ACSR (18/1)	584	459	350	255	175	106	50	418	328	250	183	125	76	36	325	256	195	142	97	59	28

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,783	1,388	1,043	743	487	271	91	766	597	448	320	209	116	39	488	380	286	204	133	74	25
3∅ 1/O ACSR (6/1)	1,151	896	673	480	314	175	59	620	483	363	259	169	94	32	424	330	248	177	116	64	22
3∅ 4/O ACSR (6/1)	814	634	476	339	222	124	42	507	395	297	211	138	77	26	368	287	215	154	101	56	19
3∅ 336.4 ACSR (18/1)	670	522	392	279	183	102	34	447	348	262	186	122	68	23	336	261	196	140	92	51	17
3∅ 477.0 ACSR (18/1)	563	438	329	235	154	85	29	397	309	232	165	108	60	20	306	239	179	128	84	47	16

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,633	1,239	893	594	337	121	-	719	545	393	261	149	53	-	461	349	252	168	95	34	-
3∅ 1/O ACSR (6/1)	1,055	800	577	383	218	78	-	579	439	317	211	120	43	-	399	303	218	145	82	30	-
3∅ 4/O ACSR (6/1)	746	566	408	271	154	55	-	472	358	258	171	97	35	-	345	262	189	125	71	26	-
3∅ 336.4 ACSR (18/1)	614	465	336	223	127	46	-	415	315	227	151	86	31	-	314	238	172	114	65	23	-
3∅ 477.0 ACSR (18/1)	516	391	282	188	107	38	-	368	279	201	134	76	27	-	286	217	156	104	59	21	-

NESC Extreme Wind (90 mph) - Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,966	1,627	1,329	1,069	844	652	490	1,055	874	714	574	453	350	263	721	597	488	392	310	239	180
1∅ 1/O ACSR (6/1)	1,707	1,413	1,153	927	731	564	423	974	806	658	529	417	322	241	681	564	460	370	292	225	169
1∅ 4/O ACSR (6/1)	1,486	1,229	1,003	806	636	490	368	898	743	606	487	384	296	222	643	532	434	349	275	212	159
1∅ 336.4 ACSR (18/1)	1,357	1,123	916	736	581	448	336	849	702	573	461	363	280	210	618	511	417	335	264	204	153
1∅ 477.0 ACSR (18/1)	1,241	1,027	838	673	531	410	307	802	664	542	435	343	265	199	593	490	400	322	254	196	147
3∅ 4 ACSR (7/1)	1,080	894	730	586	462	357	268	732	605	494	397	313	242	181	553	458	374	300	237	183	137
3∅ 1/O ACSR (6/1)	928	768	627	504	397	306	230	659	545	445	357	282	217	163	510	422	345	277	218	168	126
3∅ 4/O ACSR (6/1)	797	659	538	432	341	263	197	590	488	398	320	252	195	146	468	387	316	254	200	154	116
3∅ 336.4 ACSR (18/1)	722	597	487	392	309	238	179	547	453	370	297	234	181	136	441	365	298	239	189	146	109
3∅ 477.0 ACSR (18/1)	655	542	443	356	281	216	162	509	421	343	276	218	168	126	415	344	281	225	178	137	103

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,947	1,604	1,303	1,040	813	619	455	1,068	881	715	571	446	339	250	736	607	493	393	307	234	172
1∅ 1/O ACSR (6/1)	1,696	1,398	1,135	906	708	539	397	988	814	661	528	412	314	231	697	575	467	372	291	222	163
1∅ 4/O ACSR (6/1)	1,473	1,214	986	787	615	468	345	908	749	608	485	379	289	212	656	541	439	351	274	209	154
1∅ 336.4 ACSR (18/1)	1,344	1,108	900	718	561	427	314	857	707	574	458	358	272	201	629	519	421	336	263	200	147
1∅ 477.0 ACSR (18/1)	1,228	1,013	822	656	513	390	287	809	667	541	432	338	257	189	603	497	404	322	252	192	141
3∅ 4 ACSR (7/1)	1,068	881	715	571	446	340	250	736	607	493	393	307	234	172	562	463	376	300	234	178	131
3∅ 1/O ACSR (6/1)	917	756	614	490	383	291	214	661	545	442	353	276	210	155	517	426	346	276	216	164	121
3∅ 4/O ACSR (6/1)	786	648	526	420	328	250	184	590	487	395	315	246	188	138	473	389	316	252	197	150	111
3∅ 336.4 ACSR (18/1)	712	587	477	380	297	226	167	547	451	366	292	229	174	128	445	366	298	238	186	141	104
3∅ 477.0 ACSR (18/1)	646	533	433	345	270	205	151	508	419	340	271	212	161	119	418	345	280	223	175	133	98

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,881	1,535	1,230	963	733	537	371	1,055	861	690	540	411	301	208	733	598	479	376	286	209	145
1∅ 1/O ACSR (6/1)	1,636	1,335	1,069	838	638	467	323	974	794	636	499	379	278	192	693	565	453	355	270	198	137
1∅ 4/O ACSR (6/1)	1,420	1,158	928	727	553	405	280	893	728	583	457	348	255	176	651	531	426	333	254	186	128
1∅ 336.4 ACSR (18/1)	1,294	1,056	846	663	504	369	255	841	686	550	431	328	240	166	623	508	407	319	243	178	123
1∅ 477.0 ACSR (18/1)	1,182	964	772	605	460	337	233	792	646	518	406	309	226	156	596	486	390	305	232	170	118
3∅ 4 ACSR (7/1)	1,027	838	671	526	400	293	203	720	587	470	368	280	205	142	554	452	362	284	216	158	109
3∅ 1/O ACSR (6/1)	880	718	575	451	343	251	174	644	526	421	330	251	184	127	508	415	332	260	198	145	100
3∅ 4/O ACSR (6/1)	754	615	493	386	294	215	149	574	468	375	294	224	164	113	464	378	303	237	181	132	91
3∅ 336.4 ACSR (18/1)	683	557	446	350	266	195	135	532	434	348	272	207	152	105	435	355	285	223	170	124	86
3∅ 477.0 ACSR (18/1)	620	505	405	317	241	177	122	493	402	322	252	192	141	97	409	334	267	209	159	117	81

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,770	1,421	1,113	844	612	414	248	1,008	809	634	481	349	236	141	704	565	443	336	244	165	99
1∅ 1/O ACSR (6/1)	1,538	1,234	967	734	532	360	215	928	745	583	443	321	217	130	664	533	418	317	230	156	93
1∅ 4/O ACSR (6/1)	1,333	1,070	838	636	461	312	187	849	682	534	405	294	199	119	623	500	392	297	216	146	87
1∅ 336.4 ACSR (18/1)	1,214	975	764	579	420	284	170	799	642	503	381	277	187	112	596	478	375	284	206	139	83
1∅ 477.0 ACSR (18/1)	1,108	890	697	529	384	260	155	752	604	473	359	260	176	105	569	457	358	272	197	133	80
3∅ 4 ACSR (7/1)	962	773	605	459	333	225	135	682	547	429	325	236	160	95	528	424	332	252	183	124	74
3∅ 1/O ACSR (6/1)	825	662	519	393	285	193	115	610	489	383	291	211	143	85	484	388	304	231	167	113	68
3∅ 4/O ACSR (6/1)	706	567	444	337	244	165	99	543	435	341	259	188	127	76	440	354	277	210	152	103	62
3∅ 336.4 ACSR (18/1)	639	513	402	305	221	150	89	502	403	316	240	174	118	70	413	332	260	197	143	97	58
3∅ 477.0 ACSR (18/1)	580	465	365	277	201	136	81	465	373	292	222	161	109	65	388	311	244	185	134	91	54

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,029	842	676	532	407	300	211	709	580	466	366	280	207	145	541	442	355	279	214	158	111
3∅ 1/O ACSR (6/1)	883	722	580	456	349	258	181	637	521	418	329	252	186	130	498	407	327	257	197	145	102
3∅ 4/O ACSR (6/1)	758	619	498	391	300	221	155	569	465	374	294	225	166	116	455	372	299	235	180	133	93
3∅ 336.4 ACSR (18/1)	686	561	451	354	271	200	141	527	431	346	272	209	154	108	428	350	281	221	169	125	88
3∅ 477.0 ACSR (18/1)	623	509	409	322	246	182	128	489	400	321	253	193	143	100	403	329	265	208	159	118	83

NESC Extreme Wind (90 mph) - Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	889	700	534	388	263	155	65	623	491	374	272	184	109	46	480	378	288	209	142	84	35
3∅ 1/O ACSR (6/1)	763	600	458	333	225	133	56	558	440	335	244	165	98	41	440	347	264	192	130	77	32
3∅ 4/O ACSR (6/1)	653	515	392	285	193	114	48	497	392	299	217	147	87	36	402	316	241	175	119	70	29
3∅ 336.4 ACSR (18/1)	591	466	355	258	175	103	43	461	363	276	201	136	81	34	377	297	226	165	111	66	28
3∅ 477.0 ACSR (18/1)	537	423	322	234	159	94	39	427	336	256	186	126	75	31	354	279	213	155	105	62	26

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	687	498	330	184	58	-	-	487	353	234	131	41	-	-	377	273	181	101	32	-	-
3∅ 1/O ACSR (6/1)	589	426	283	158	50	-	-	435	315	209	117	37	-	-	345	250	166	93	29	-	-
3∅ 4/O ACSR (6/1)	504	365	242	135	43	-	-	387	280	186	104	33	-	-	315	228	151	84	27	-	-
3∅ 336.4 ACSR (18/1)	456	330	219	122	39	-	-	359	259	172	96	30	-	-	295	214	142	79	25	-	-
3∅ 477.0 ACSR (18/1)	414	300	199	111	35	-	-	332	240	159	89	28	-	-	277	200	133	74	23	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	996	805	637	490	363	254	163	719	581	459	353	262	183	118	562	454	359	276	205	143	92
3∅ 1/O ACSR (6/1)	853	689	545	419	310	218	139	641	518	410	315	233	163	105	513	415	328	252	187	131	84
3∅ 4/O ACSR (6/1)	730	590	466	359	266	186	119	569	460	364	280	207	145	93	466	377	298	229	170	119	76
3∅ 336.4 ACSR (18/1)	660	533	422	324	240	168	108	526	425	336	258	191	134	86	437	353	279	215	159	111	71
3∅ 477.0 ACSR (18/1)	599	484	383	294	218	153	98	486	393	310	239	177	124	79	409	330	261	201	149	104	67

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	963	773	605	459	332	224	134	686	550	431	327	237	160	95	532	427	334	254	184	124	74
3∅ 1/O ACSR (6/1)	825	662	518	393	285	192	115	613	492	385	292	211	143	85	487	391	306	232	168	114	68
3∅ 4/O ACSR (6/1)	706	567	444	337	244	165	98	545	437	342	260	188	127	76	443	356	279	211	153	103	62
3∅ 336.4 ACSR (18/1)	639	513	402	304	221	149	89	504	404	317	240	174	117	70	416	334	261	198	143	97	58
3∅ 477.0 ACSR (18/1)	580	465	364	276	200	135	80	466	374	293	222	161	109	65	390	313	245	186	135	91	54

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	898	707	539	392	265	157	66	646	509	388	282	191	113	47	505	397	303	220	149	88	37
3∅ 1/O ACSR (6/1)	769	606	461	336	227	134	56	577	454	346	252	170	101	42	461	363	277	201	136	81	34
3∅ 4/O ACSR (6/1)	658	518	395	287	194	115	48	512	403	307	223	151	89	37	419	330	251	183	124	73	31
3∅ 336.4 ACSR (18/1)	595	469	357	260	176	104	44	473	372	284	206	140	83	35	392	309	235	171	116	69	29
3∅ 477.0 ACSR (18/1)	540	425	324	236	159	94	39	437	344	262	191	129	76	32	368	289	221	160	109	64	27

NESC Extreme Wind (90 mph) - Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,977	2,470	2,024	1,633	1,295	1,006	763	1,598	1,326	1,086	877	695	540	409	1,092	906	742	599	475	369	280
1∅ 1/O ACSR (6/1)	2,597	2,155	1,766	1,425	1,130	878	665	1,482	1,230	1,007	813	645	501	380	1,036	860	705	569	451	350	266
1∅ 4/O ACSR (6/1)	2,260	1,876	1,537	1,240	984	764	579	1,365	1,133	928	749	594	462	350	978	812	665	537	426	331	251
1∅ 336.4 ACSR (18/1)	2,064	1,713	1,403	1,132	898	698	529	1,291	1,072	878	709	562	437	331	940	780	639	516	409	318	241
1∅ 477.0 ACSR (18/1)	1,887	1,566	1,283	1,036	821	638	483	1,220	1,012	829	669	531	412	313	901	748	613	495	392	305	231
3∅ 4 ACSR (7/1)	1,643	1,364	1,117	902	715	556	421	1,113	924	757	611	484	376	285	842	698	572	462	366	285	216
3∅ 1/O ACSR (6/1)	1,412	1,172	960	775	614	477	362	1,002	831	681	550	436	339	257	776	644	528	426	338	262	199
3∅ 4/O ACSR (6/1)	1,212	1,006	824	665	527	410	310	897	744	610	492	390	303	230	712	591	484	391	310	241	182
3∅ 336.4 ACSR (18/1)	1,098	911	746	602	478	371	281	833	691	566	457	362	282	213	671	557	456	368	292	227	172
3∅ 477.0 ACSR (18/1)	997	827	678	547	434	337	255	773	642	526	424	337	262	198	632	524	430	347	275	214	162

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,972	2,459	2,006	1,611	1,269	976	729	1,631	1,349	1,101	884	696	536	400	1,124	930	759	609	480	369	276
1∅ 1/O ACSR (6/1)	2,588	2,142	1,748	1,403	1,105	850	635	1,508	1,248	1,018	818	644	495	370	1,064	880	719	577	454	349	261
1∅ 4/O ACSR (6/1)	2,249	1,861	1,519	1,219	960	739	552	1,386	1,147	936	752	592	455	340	1,002	829	677	543	428	329	246
1∅ 336.4 ACSR (18/1)	2,052	1,698	1,386	1,112	876	674	503	1,309	1,083	884	710	559	430	321	961	795	649	521	410	316	236
1∅ 477.0 ACSR (18/1)	1,875	1,552	1,266	1,017	801	616	460	1,235	1,022	834	669	527	405	303	920	761	621	499	393	302	226
3∅ 4 ACSR (7/1)	1,631	1,350	1,101	884	696	536	400	1,124	930	759	609	480	369	276	857	709	579	465	366	282	210
3∅ 1/O ACSR (6/1)	1,400	1,158	945	759	598	460	343	1,009	835	681	547	431	331	247	789	653	533	428	337	259	193
3∅ 4/O ACSR (6/1)	1,201	993	811	651	513	394	294	901	746	608	489	385	296	221	721	597	487	391	308	237	177
3∅ 336.4 ACSR (18/1)	1,087	899	734	589	464	357	267	836	691	564	453	357	274	205	679	562	458	368	290	223	166
3∅ 477.0 ACSR (18/1)	987	817	666	535	421	324	242	775	641	523	420	331	255	190	638	528	431	346	273	210	157

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,891	2,372	1,914	1,513	1,167	870	620	1,622	1,331	1,074	849	655	488	348	1,127	925	746	590	455	339	242
1∅ 1/O ACSR (6/1)	2,514	2,063	1,664	1,316	1,015	757	539	1,496	1,228	991	783	604	450	321	1,065	874	705	558	430	321	228
1∅ 4/O ACSR (6/1)	2,182	1,790	1,444	1,142	881	657	468	1,372	1,125	908	718	554	413	294	1,000	821	662	524	404	301	215
1∅ 336.4 ACSR (18/1)	1,989	1,632	1,317	1,041	803	599	427	1,293	1,061	856	677	522	389	277	958	786	634	501	387	288	205
1∅ 477.0 ACSR (18/1)	1,816	1,490	1,202	951	733	547	390	1,218	999	806	637	491	367	261	916	751	606	479	370	276	196
3∅ 4 ACSR (7/1)	1,578	1,295	1,045	826	637	475	339	1,106	907	732	579	446	333	237	851	698	563	446	344	256	183
3∅ 1/O ACSR (6/1)	1,353	1,110	896	708	546	407	290	990	812	656	518	400	298	212	781	641	517	409	315	235	168
3∅ 4/O ACSR (6/1)	1,159	951	767	607	468	349	249	882	724	584	462	356	266	189	712	584	472	373	288	214	153
3∅ 336.4 ACSR (18/1)	1,049	861	695	549	424	316	225	817	670	541	428	330	246	175	669	549	443	350	270	201	144
3∅ 477.0 ACSR (18/1)	952	781	630	498	384	287	204	757	621	501	396	306	228	162	628	515	416	329	254	189	135

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,740	2,216	1,755	1,351	1,002	703	451	1,560	1,262	999	769	570	400	257	1,090	882	698	538	399	280	179
1∅ 1/O ACSR (6/1)	2,380	1,926	1,524	1,174	870	611	392	1,436	1,162	920	708	525	368	236	1,028	832	659	507	376	264	169
1∅ 4/O ACSR (6/1)	2,063	1,669	1,322	1,018	754	529	339	1,315	1,063	842	648	481	337	216	964	780	618	476	353	247	159
1∅ 336.4 ACSR (18/1)	1,880	1,521	1,204	927	687	482	309	1,238	1,001	793	610	452	317	204	922	746	591	455	337	237	152
1∅ 477.0 ACSR (18/1)	1,716	1,388	1,099	846	627	440	282	1,164	942	746	574	426	299	192	881	713	564	434	322	226	145
3∅ 4 ACSR (7/1)	1,490	1,205	954	735	545	382	245	1,056	854	676	521	386	271	174	817	661	524	403	299	210	134
3∅ 1/O ACSR (6/1)	1,277	1,033	818	630	467	328	210	944	764	605	465	345	242	155	749	606	480	369	274	192	123
3∅ 4/O ACSR (6/1)	1,093	885	700	539	400	281	180	840	679	538	414	307	215	138	682	552	437	336	249	175	112
3∅ 336.4 ACSR (18/1)	989	800	634	488	362	254	163	777	629	498	383	284	199	128	640	518	410	316	234	164	105
3∅ 477.0 ACSR (18/1)	897	726	575	443	328	230	148	719	582	461	355	263	185	118	600	485	384	296	219	154	99

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,583	1,302	1,053	836	649	488	352	1,091	897	726	576	447	336	243	832	684	554	440	341	256	185
3∅ 1/O ACSR (6/1)	1,359	1,117	904	718	557	419	302	979	805	652	517	401	302	218	766	630	509	404	314	236	170
3∅ 4/O ACSR (6/1)	1,165	958	775	616	477	359	259	875	719	582	462	358	270	195	700	576	466	370	287	216	156
3∅ 336.4 ACSR (18/1)	1,055	868	702	557	432	325	235	811	667	540	429	332	250	180	659	542	438	348	270	203	147
3∅ 477.0 ACSR (18/1)	958	788	637	506	392	295	213	752	619	501	398	308	232	167	620	509	412	327	254	191	138

NESC Extreme Wind (90 mph) - Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,401	1,118	868	649	460	298	162	982	783	608	455	323	209	113	756	603	468	350	248	161	87
3∅ 1/O ACSR (6/1)	1,201	958	744	557	395	256	139	879	702	545	408	289	187	102	694	553	430	321	228	148	80
3∅ 4/O ACSR (6/1)	1,030	821	638	477	338	219	119	784	625	485	363	257	167	91	633	505	392	293	208	135	73
3∅ 336.4 ACSR (18/1)	932	743	577	432	306	198	108	726	579	450	336	238	155	84	594	474	368	275	195	127	69
3∅ 477.0 ACSR (18/1)	846	675	524	392	278	180	98	672	536	416	312	221	143	78	558	445	346	259	183	119	64

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,123	838	587	367	178	15	-	795	594	416	260	126	11	-	616	460	322	202	97	8	-
3∅ 1/O ACSR (6/1)	962	718	503	315	152	13	-	711	531	372	233	112	9	-	564	421	295	185	89	8	-
3∅ 4/O ACSR (6/1)	824	615	431	270	130	11	-	633	472	331	207	100	8	-	514	383	269	168	81	7	-
3∅ 336.4 ACSR (18/1)	745	556	390	244	118	10	-	586	437	306	192	93	8	-	482	360	252	158	76	6	-
3∅ 477.0 ACSR (18/1)	676	505	354	221	107	9	-	542	405	283	177	86	7	-	452	338	236	148	71	6	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,538	1,251	999	778	586	423	285	1,109	903	720	561	423	305	205	867	706	563	439	331	238	161
3∅ 1/O ACSR (6/1)	1,317	1,071	855	666	502	362	244	989	805	642	500	377	272	183	792	645	514	401	302	218	147
3∅ 4/O ACSR (6/1)	1,127	917	732	570	430	310	208	878	714	570	444	335	241	162	719	585	467	364	274	198	133
3∅ 336.4 ACSR (18/1)	1,019	829	662	515	388	280	189	811	660	527	410	309	223	150	674	548	438	341	257	185	125
3∅ 477.0 ACSR (18/1)	924	752	600	467	352	254	171	750	610	487	379	286	206	139	631	513	410	319	241	173	117

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,492	1,207	955	735	545	382	245	1,062	859	680	523	388	272	174	824	667	528	406	301	211	135
3∅ 1/O ACSR (6/1)	1,278	1,033	818	630	467	327	209	949	767	607	468	347	243	156	755	610	483	372	276	193	124
3∅ 4/O ACSR (6/1)	1,094	885	700	539	400	280	179	844	682	540	416	308	216	138	687	555	440	338	251	176	113
3∅ 336.4 ACSR (18/1)	990	801	634	488	361	253	162	780	631	500	385	285	200	128	644	521	412	317	235	165	106
3∅ 477.0 ACSR (18/1)	898	726	575	442	328	230	147	722	584	462	356	264	185	118	604	488	387	298	220	155	99

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,401	1,115	863	642	451	287	149	1,008	802	621	462	324	207	107	787	627	485	361	253	161	84
3∅ 1/O ACSR (6/1)	1,200	955	738	549	386	246	128	900	716	554	412	289	184	96	719	572	443	329	231	147	77
3∅ 4/O ACSR (6/1)	1,027	817	632	470	330	210	109	799	635	492	366	257	164	85	653	520	402	299	210	134	70
3∅ 336.4 ACSR (18/1)	929	739	572	425	299	190	99	738	587	454	338	237	151	79	612	487	377	280	197	125	65
3∅ 477.0 ACSR (18/1)	842	670	518	386	271	173	90	682	543	420	312	219	140	73	573	456	353	263	184	117	61

NESC Extreme Wind (120 mph) - Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,820	1,491	1,202	951	735	553	400	977	800	645	511	395	297	215	668	547	441	349	270	203	147
1∅ 1/O ACSR (6/1)	1,574	1,288	1,037	819	632	473	341	898	735	592	467	360	270	194	628	514	414	327	252	189	136
1∅ 4/O ACSR (6/1)	1,370	1,121	902	713	550	412	297	828	677	545	431	332	249	179	593	485	391	308	238	178	128
1∅ 336.4 ACSR (18/1)	1,251	1,024	824	651	502	376	271	783	640	516	407	314	235	169	570	466	375	296	229	171	123
1∅ 477.0 ACSR (18/1)	1,144	936	754	595	459	344	248	739	605	487	385	297	222	160	546	447	360	284	219	164	118
3∅ 4 ACSR (7/1)	996	815	656	518	400	299	216	675	552	444	351	271	203	146	510	417	336	265	205	153	110
3∅ 1/O ACSR (6/1)	856	700	564	445	343	257	185	607	497	400	316	244	182	131	471	385	310	245	189	141	102
3∅ 4/O ACSR (6/1)	735	601	484	382	295	221	159	544	445	358	283	218	163	118	431	353	284	224	173	130	93
3∅ 336.4 ACSR (18/1)	665	544	438	346	267	200	144	505	413	333	263	203	152	109	407	333	268	212	163	122	88
3∅ 477.0 ACSR (18/1)	604	495	398	314	242	182	131	469	384	309	244	188	141	102	383	313	252	199	154	115	83

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,792	1,460	1,168	915	698	514	360	983	801	641	502	383	282	198	678	552	442	346	264	194	136
1∅ 1/O ACSR (6/1)	1,561	1,272	1,018	797	608	447	314	910	741	593	464	354	261	183	642	523	418	328	250	184	129
1∅ 4/O ACSR (6/1)	1,356	1,105	884	693	528	389	273	836	681	545	427	326	240	168	604	492	394	309	235	173	121
1∅ 336.4 ACSR (18/1)	1,237	1,008	807	632	482	355	249	789	643	515	403	307	226	159	579	472	378	296	226	166	116
1∅ 477.0 ACSR (18/1)	1,131	921	737	578	440	324	227	745	607	485	380	290	213	150	555	452	362	283	216	159	112
3∅ 4 ACSR (7/1)	984	801	641	502	383	282	198	678	552	442	346	264	194	136	517	421	337	264	201	148	104
3∅ 1/O ACSR (6/1)	844	688	550	431	329	242	170	608	496	397	311	237	174	122	476	387	310	243	185	136	96
3∅ 4/O ACSR (6/1)	724	590	472	370	282	207	146	543	443	354	278	212	156	109	435	354	284	222	169	125	87
3∅ 336.4 ACSR (18/1)	656	534	427	335	255	188	132	504	411	329	257	196	144	101	409	333	267	209	159	117	82
3∅ 477.0 ACSR (18/1)	595	485	388	304	232	171	120	467	381	305	239	182	134	94	385	314	251	197	150	110	77

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,725	1,388	1,093	837	617	430	275	968	779	613	469	346	241	154	672	541	426	326	240	168	107
1∅ 1/O ACSR (6/1)	1,500	1,207	951	728	536	374	239	893	719	566	433	319	223	142	635	511	403	308	227	158	101
1∅ 4/O ACSR (6/1)	1,301	1,048	825	631	465	325	207	818	659	519	397	293	204	130	597	480	378	290	213	149	95
1∅ 336.4 ACSR (18/1)	1,186	955	752	576	424	296	189	771	621	489	374	276	192	123	571	460	362	277	204	143	91
1∅ 477.0 ACSR (18/1)	1,083	872	687	526	387	270	173	726	585	460	352	260	181	116	546	440	346	265	195	136	87
3∅ 4 ACSR (7/1)	941	758	597	457	337	235	150	660	531	418	320	236	165	105	508	409	322	246	182	127	81
3∅ 1/O ACSR (6/1)	807	650	512	392	289	201	129	591	476	374	287	211	147	94	466	375	295	226	167	116	74
3∅ 4/O ACSR (6/1)	692	557	438	336	247	173	110	526	424	334	255	188	131	84	425	342	269	206	152	106	68
3∅ 336.4 ACSR (18/1)	626	504	397	304	224	156	100	488	392	309	237	174	122	78	399	321	253	194	143	100	64
3∅ 477.0 ACSR (18/1)	568	457	360	276	203	142	91	452	364	286	219	161	113	72	375	302	238	182	134	93	60

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,612	1,273	975	717	495	307	151	918	725	555	408	282	175	86	641	507	388	285	197	122	60
1∅ 1/O ACSR (6/1)	1,400	1,106	847	623	430	267	131	845	667	511	376	260	161	79	605	478	366	269	186	115	57
1∅ 4/O ACSR (6/1)	1,214	959	735	540	373	231	113	773	611	468	344	238	147	72	567	448	343	252	174	108	53
1∅ 336.4 ACSR (18/1)	1,106	873	669	492	340	211	103	728	575	441	324	224	139	68	543	429	328	241	167	103	51
1∅ 477.0 ACSR (18/1)	1,010	797	611	449	310	192	94	685	541	415	305	210	130	64	518	409	314	231	159	99	48
3∅ 4 ACSR (7/1)	877	692	530	390	269	167	82	621	490	376	276	191	118	58	481	380	291	214	148	92	45
3∅ 1/O ACSR (6/1)	751	593	455	334	231	143	70	555	439	336	247	171	106	52	441	348	267	196	135	84	41
3∅ 4/O ACSR (6/1)	643	508	389	286	198	123	60	494	390	299	220	152	94	46	401	317	243	178	123	76	37
3∅ 336.4 ACSR (18/1)	582	460	352	259	179	111	54	457	361	277	203	140	87	43	376	297	228	167	116	72	35
3∅ 477.0 ACSR (18/1)	528	417	320	235	162	101	49	423	334	256	188	130	81	40	353	279	214	157	108	67	33

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	945	762	602	463	344	243	159	651	525	415	319	237	167	109	496	401	317	243	181	128	83
3∅ 1/O ACSR (6/1)	811	654	517	398	295	208	136	584	471	373	287	213	150	98	457	369	291	224	166	117	77
3∅ 4/O ACSR (6/1)	695	561	443	341	253	179	117	522	421	333	256	190	134	88	418	337	266	205	152	107	70
3∅ 336.4 ACSR (18/1)	630	508	401	309	229	162	106	484	391	309	237	176	124	81	393	317	251	193	143	101	66
3∅ 477.0 ACSR (18/1)	571	461	364	280	208	147	96	449	362	286	220	163	115	75	370	298	236	181	135	95	62

NESC Extreme Wind (120 mph) - Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	804	620	459	319	199	97	13	563	435	322	224	140	68	9	434	335	248	172	107	53	7
3∅ 1/O ACSR (6/1)	689	532	394	274	171	83	11	505	389	288	200	125	61	8	398	307	227	158	99	48	6
3∅ 4/O ACSR (6/1)	591	456	337	235	146	72	9	450	347	257	179	111	54	7	363	280	207	144	90	44	6
3∅ 336.4 ACSR (18/1)	535	413	305	212	132	65	8	416	321	238	165	103	50	7	341	263	195	135	84	41	5
3∅ 477.0 ACSR (18/1)	485	374	277	193	120	59	8	386	298	220	153	96	47	6	320	247	183	127	79	39	5

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	602	417	255	115	-	-	-	426	296	181	81	-	-	-	330	229	140	63	-	-	-
3∅ 1/O ACSR (6/1)	515	357	219	98	-	-	-	381	264	162	73	-	-	-	302	210	128	58	-	-	-
3∅ 4/O ACSR (6/1)	442	306	187	84	-	-	-	339	235	144	65	-	-	-	275	191	117	53	-	-	-
3∅ 336.4 ACSR (18/1)	399	277	170	76	-	-	-	314	218	133	60	-	-	-	258	179	110	49	-	-	-
3∅ 477.0 ACSR (18/1)	362	251	154	69	-	-	-	290	201	123	55	-	-	-	242	168	103	46	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	910	724	561	420	298	195	110	656	522	405	303	215	141	79	513	409	317	237	168	110	62
3∅ 1/O ACSR (6/1)	779	620	481	359	255	167	94	585	466	361	270	192	126	71	469	373	289	216	154	101	57
3∅ 4/O ACSR (6/1)	667	531	411	308	219	143	80	520	414	321	240	170	112	63	426	339	263	196	140	91	51
3∅ 336.4 ACSR (18/1)	603	480	372	278	198	129	73	480	382	296	221	157	103	58	399	317	246	184	131	86	48
3∅ 477.0 ACSR (18/1)	547	435	337	252	179	117	66	444	353	274	205	145	95	54	373	297	230	172	122	80	45

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	877	692	530	389	268	166	81	624	493	377	277	191	118	57	485	383	293	215	148	92	45
3∅ 1/O ACSR (6/1)	751	593	454	334	230	142	69	558	440	337	248	171	106	51	444	350	268	197	136	84	41
3∅ 4/O ACSR (6/1)	643	508	389	286	197	122	59	496	392	300	220	152	94	46	404	319	244	179	124	76	37
3∅ 336.4 ACSR (18/1)	582	459	352	258	178	110	54	459	362	277	204	140	87	42	379	299	229	168	116	72	35
3∅ 477.0 ACSR (18/1)	528	417	319	234	162	100	49	424	335	257	188	130	80	39	355	280	215	158	109	67	33

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	812	627	464	322	201	98	13	584	451	334	232	145	71	9	456	352	261	181	113	55	7
3∅ 1/O ACSR (6/1)	695	536	397	276	172	84	11	521	402	298	207	129	63	8	417	322	238	165	103	50	6
3∅ 4/O ACSR (6/1)	595	459	340	236	147	72	9	463	357	264	184	115	56	7	379	292	216	150	94	46	6
3∅ 336.4 ACSR (18/1)	538	415	307	214	133	65	8	428	330	244	170	106	52	7	355	274	203	141	88	43	5
3∅ 477.0 ACSR (18/1)	488	377	279	194	121	59	8	395	305	226	157	98	48	6	332	256	190	132	82	40	5

NESC Extreme Wind (120 mph) - Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,803	2,308	1,873	1,493	1,166	889	656	1,505	1,239	1,005	802	626	477	352	1,028	847	687	548	428	326	241
1∅ 1/O ACSR (6/1)	2,446	2,014	1,634	1,303	1,018	775	572	1,395	1,149	932	743	581	442	326	976	804	652	520	406	309	228
1∅ 4/O ACSR (6/1)	2,128	1,752	1,422	1,134	886	675	498	1,286	1,059	859	685	535	408	301	921	759	615	491	383	292	216
1∅ 336.4 ACSR (18/1)	1,943	1,600	1,298	1,035	809	616	455	1,216	1,001	812	648	506	385	284	885	729	591	471	368	280	207
1∅ 477.0 ACSR (18/1)	1,777	1,463	1,187	947	740	563	416	1,149	946	767	612	478	364	269	849	699	567	452	353	269	199
3∅ 4 ACSR (7/1)	1,548	1,274	1,034	824	644	491	362	1,048	863	700	558	436	332	245	793	653	529	422	330	251	185
3∅ 1/O ACSR (6/1)	1,329	1,095	888	708	553	421	311	943	777	630	503	393	299	221	731	602	488	389	304	232	171
3∅ 4/O ACSR (6/1)	1,141	940	762	608	475	362	267	845	695	564	450	351	268	198	670	552	448	357	279	212	157
3∅ 336.4 ACSR (18/1)	1,034	851	691	551	430	328	242	784	646	524	418	326	249	183	632	520	422	337	263	200	148
3∅ 477.0 ACSR (18/1)	939	773	627	500	391	298	220	728	600	487	388	303	231	170	595	490	397	317	248	189	139

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,796	2,294	1,853	1,469	1,138	856	621	1,534	1,259	1,017	806	625	470	341	1,057	868	701	556	430	324	235
1∅ 1/O ACSR (6/1)	2,435	1,999	1,614	1,280	991	746	541	1,419	1,165	941	746	578	435	315	1,001	822	664	526	408	307	222
1∅ 4/O ACSR (6/1)	2,116	1,737	1,403	1,112	861	648	470	1,304	1,070	865	685	531	400	290	943	774	625	495	384	289	209
1∅ 336.4 ACSR (18/1)	1,931	1,584	1,280	1,014	786	591	429	1,231	1,011	816	647	501	377	273	904	742	599	475	368	277	201
1∅ 477.0 ACSR (18/1)	1,764	1,448	1,170	927	718	541	392	1,162	953	770	610	473	356	258	866	711	574	455	352	265	192
3∅ 4 ACSR (7/1)	1,535	1,259	1,017	806	625	470	341	1,057	868	701	556	430	324	235	807	662	535	424	328	247	179
3∅ 1/O ACSR (6/1)	1,317	1,081	873	692	536	403	292	949	779	629	499	386	291	211	742	609	492	390	302	227	165
3∅ 4/O ACSR (6/1)	1,130	927	749	594	460	346	251	848	696	562	446	345	260	188	679	557	450	357	276	208	151
3∅ 336.4 ACSR (18/1)	1,023	839	678	537	416	313	227	786	645	521	413	320	241	175	639	524	423	336	260	196	142
3∅ 477.0 ACSR (18/1)	929	762	615	488	378	284	206	729	599	483	383	297	223	162	601	493	398	316	244	184	133

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,713	2,205	1,759	1,370	1,035	749	511	1,522	1,237	987	769	580	421	287	1,058	860	686	534	403	292	199
1∅ 1/O ACSR (6/1)	2,360	1,918	1,530	1,191	900	652	444	1,404	1,141	910	709	535	388	264	1,000	812	648	505	381	276	188
1∅ 4/O ACSR (6/1)	2,047	1,664	1,327	1,034	781	566	385	1,287	1,046	835	650	491	356	242	939	763	609	474	358	259	177
1∅ 336.4 ACSR (18/1)	1,866	1,517	1,210	942	712	516	351	1,213	986	787	613	463	335	228	899	731	583	454	343	248	169
1∅ 477.0 ACSR (18/1)	1,704	1,385	1,105	860	650	471	321	1,143	929	741	577	436	316	215	860	699	557	434	328	237	162
3∅ 4 ACSR (7/1)	1,481	1,204	960	748	565	409	279	1,038	844	673	524	396	287	195	799	649	518	403	305	221	150
3∅ 1/O ACSR (6/1)	1,270	1,032	823	641	484	351	239	929	755	602	469	354	257	175	733	596	475	370	279	202	138
3∅ 4/O ACSR (6/1)	1,088	884	705	549	415	301	205	828	673	537	418	316	229	156	669	543	433	338	255	185	126
3∅ 336.4 ACSR (18/1)	985	800	638	497	375	272	185	767	623	497	387	292	212	144	628	510	407	317	239	173	118
3∅ 477.0 ACSR (18/1)	894	726	579	451	341	247	168	711	578	461	359	271	196	134	590	479	382	298	225	163	111

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,560	2,049	1,598	1,206	868	581	340	1,458	1,166	910	687	494	331	194	1,019	815	636	480	346	231	135
1∅ 1/O ACSR (6/1)	2,225	1,780	1,389	1,048	754	505	296	1,342	1,074	838	632	455	305	178	961	769	600	453	326	218	128
1∅ 4/O ACSR (6/1)	1,928	1,543	1,204	908	654	438	256	1,228	983	767	579	417	279	163	901	721	563	425	306	205	120
1∅ 336.4 ACSR (18/1)	1,757	1,406	1,097	828	596	399	233	1,157	925	722	545	392	262	154	862	690	538	406	292	196	115
1∅ 477.0 ACSR (18/1)	1,604	1,283	1,001	755	544	364	213	1,088	871	679	513	369	247	145	823	659	514	388	279	187	109
3∅ 4 ACSR (7/1)	1,392	1,114	869	656	472	316	185	987	789	616	465	335	224	131	764	611	477	360	259	173	102
3∅ 1/O ACSR (6/1)	1,193	955	745	562	405	271	159	882	706	551	416	299	200	117	700	560	437	330	237	159	93
3∅ 4/O ACSR (6/1)	1,022	818	638	481	347	232	136	785	628	490	370	266	178	104	637	510	398	300	216	145	85
3∅ 336.4 ACSR (18/1)	925	740	577	436	314	210	123	726	581	453	342	246	165	97	598	478	373	282	203	136	79
3∅ 477.0 ACSR (18/1)	839	671	524	395	284	190	111	672	538	420	317	228	153	89	561	449	350	264	190	127	75

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,487	1,211	969	759	577	422	293	1,024	835	668	523	397	291	202	781	637	510	399	303	222	154
3∅ 1/O ACSR (6/1)	1,276	1,040	832	651	495	362	251	920	749	600	469	357	261	181	719	586	469	367	279	204	142
3∅ 4/O ACSR (6/1)	1,094	892	714	558	425	311	216	821	669	536	419	319	233	162	658	536	429	335	255	187	130
3∅ 336.4 ACSR (18/1)	991	807	646	506	384	281	195	762	621	497	389	296	216	150	619	504	403	316	240	176	122
3∅ 477.0 ACSR (18/1)	900	733	587	459	349	255	177	707	576	461	361	274	201	139	582	474	379	297	226	165	115

NESC Extreme Wind (120 mph) - Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,304	1,027	783	571	388	232	102	914	720	549	400	272	163	72	703	554	422	308	209	125	55
3∅ 1/O ACSR (6/1)	1,118	881	672	490	333	199	88	819	645	492	358	244	146	64	646	508	388	283	192	115	51
3∅ 4/O ACSR (6/1)	958	755	576	420	285	171	75	729	574	438	319	217	130	57	589	464	354	258	175	105	46
3∅ 336.4 ACSR (18/1)	867	683	521	380	258	155	68	675	532	406	296	201	120	53	553	436	332	242	165	99	43
3∅ 477.0 ACSR (18/1)	787	620	473	345	234	140	62	626	493	376	274	186	112	49	519	409	312	227	155	93	41

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,025	747	502	289	105	-	-	726	529	356	205	74	-	-	562	410	275	158	58	-	-
3∅ 1/O ACSR (6/1)	878	640	430	247	90	-	-	649	473	318	183	67	-	-	515	375	252	145	53	-	-
3∅ 4/O ACSR (6/1)	752	548	368	212	77	-	-	578	421	283	163	59	-	-	469	342	230	132	48	-	-
3∅ 336.4 ACSR (18/1)	681	496	333	192	70	-	-	535	389	262	151	55	-	-	440	321	216	124	45	-	-
3∅ 477.0 ACSR (18/1)	618	450	302	174	63	-	-	495	361	242	139	51	-	-	413	301	202	116	42	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,440	1,160	913	698	513	356	224	1,038	836	659	504	370	257	162	812	654	515	394	290	201	126
3∅ 1/O ACSR (6/1)	1,233	993	782	598	439	305	192	926	746	587	449	330	229	144	742	597	470	360	264	183	115
3∅ 4/O ACSR (6/1)	1,055	849	669	512	376	261	164	822	662	521	399	293	203	128	673	542	427	327	240	166	105
3∅ 336.4 ACSR (18/1)	954	768	605	463	340	236	148	759	612	482	368	271	188	118	631	508	400	306	225	156	98
3∅ 477.0 ACSR (18/1)	865	697	548	420	308	214	135	702	565	445	340	250	174	109	591	476	375	286	211	146	92

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,394	1,115	870	656	472	316	184	992	794	619	467	336	225	131	770	616	481	363	261	174	102
3∅ 1/O ACSR (6/1)	1,194	955	745	562	404	270	158	887	709	553	417	300	201	117	705	564	440	332	239	160	93
3∅ 4/O ACSR (6/1)	1,023	818	638	481	346	231	135	788	631	492	371	267	178	104	642	513	400	302	217	145	85
3∅ 336.4 ACSR (18/1)	925	740	577	435	313	209	122	729	583	455	343	247	165	96	602	481	376	283	204	136	80
3∅ 477.0 ACSR (18/1)	839	671	524	395	284	190	111	675	540	421	318	229	153	89	564	451	352	266	191	128	75

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,303	1,023	777	563	378	220	89	938	736	559	405	272	159	64	732	575	437	316	212	124	50
3∅ 1/O ACSR (6/1)	1,116	876	665	482	323	189	76	837	657	499	361	242	141	57	669	525	399	289	194	113	46
3∅ 4/O ACSR (6/1)	955	750	569	412	277	162	65	743	583	443	321	215	126	51	608	477	362	262	176	103	41
3∅ 336.4 ACSR (18/1)	864	678	515	373	250	146	59	686	539	409	296	199	116	47	569	447	339	246	165	96	39
3∅ 477.0 ACSR (18/1)	783	615	467	338	227	132	53	635	498	378	274	184	107	43	533	419	318	230	155	90	36

NESC Extreme Wind (150 mph) - Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,632	1,315	1,038	799	596	425	285	876	706	557	429	320	228	153	599	482	381	293	219	156	104
1∅ 1/O ACSR (6/1)	1,403	1,128	888	681	504	357	236	800	643	506	388	288	203	134	560	450	354	272	201	142	94
1∅ 4/O ACSR (6/1)	1,221	981	773	592	439	310	205	738	593	467	358	265	188	124	529	425	334	256	190	134	89
1∅ 336.4 ACSR (18/1)	1,115	896	705	541	401	283	187	698	561	441	338	251	177	117	508	408	321	246	182	129	85
1∅ 477.0 ACSR (18/1)	1,020	820	645	495	366	259	171	659	530	417	320	237	168	111	487	391	308	236	175	124	82
3∅ 4 ACSR (7/1)	888	714	562	431	319	226	149	601	483	380	292	216	153	101	455	365	288	221	163	116	76
3∅ 1/O ACSR (6/1)	763	613	483	370	274	194	128	541	435	342	263	195	138	91	419	337	265	203	151	107	70
3∅ 4/O ACSR (6/1)	655	526	414	318	235	166	110	484	389	307	235	174	123	81	385	309	243	187	138	98	65
3∅ 336.4 ACSR (18/1)	593	477	375	288	213	151	100	450	362	285	218	162	114	76	362	291	229	176	130	92	61
3∅ 477.0 ACSR (18/1)	539	433	341	261	194	137	90	418	336	264	203	150	106	70	341	274	216	166	123	87	57

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,593	1,274	995	755	550	378	238	874	699	546	414	302	208	130	603	482	376	285	208	143	90
1∅ 1/O ACSR (6/1)	1,388	1,110	867	657	479	330	207	809	647	505	383	279	192	121	571	456	356	270	197	136	85
1∅ 4/O ACSR (6/1)	1,206	964	753	571	416	286	180	743	594	464	352	257	177	111	537	430	336	254	185	128	80
1∅ 336.4 ACSR (18/1)	1,100	880	687	521	380	261	164	702	561	438	332	242	167	105	515	412	322	244	178	122	77
1∅ 477.0 ACSR (18/1)	1,005	804	628	476	347	239	150	662	529	413	314	228	157	99	493	394	308	234	170	117	74
3∅ 4 ACSR (7/1)	875	699	546	414	302	208	131	603	482	376	285	208	143	90	460	367	287	218	159	109	69
3∅ 1/O ACSR (6/1)	751	600	469	355	259	178	112	541	433	338	256	187	128	81	423	338	264	200	146	100	63
3∅ 4/O ACSR (6/1)	644	515	402	305	222	153	96	483	386	302	229	167	115	72	387	309	242	183	133	92	58
3∅ 336.4 ACSR (18/1)	583	466	364	276	201	138	87	448	358	280	212	155	106	67	364	291	227	172	126	86	54
3∅ 477.0 ACSR (18/1)	529	423	330	251	183	126	79	416	332	260	197	143	99	62	342	274	214	162	118	81	51

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,523	1,200	918	674	467	293	151	855	673	515	378	262	165	85	594	468	358	263	182	114	59
1∅ 1/O ACSR (6/1)	1,325	1,044	798	586	406	255	131	788	621	475	349	242	152	78	561	442	338	248	172	108	56
1∅ 4/O ACSR (6/1)	1,150	906	693	509	352	221	114	723	569	435	320	222	139	72	527	415	318	233	162	102	52
1∅ 336.4 ACSR (18/1)	1,048	825	631	464	321	202	104	681	537	410	302	209	131	68	505	398	304	223	155	97	50
1∅ 477.0 ACSR (18/1)	957	754	576	424	293	184	95	642	505	387	284	197	124	64	483	380	291	214	148	93	48
3∅ 4 ACSR (7/1)	832	655	501	368	255	160	82	583	459	351	258	179	112	58	448	353	270	198	137	86	44
3∅ 1/O ACSR (6/1)	713	562	429	316	219	137	71	522	411	314	231	160	100	52	412	324	248	182	126	79	41
3∅ 4/O ACSR (6/1)	611	481	368	270	187	118	61	465	366	280	206	143	90	46	375	296	226	166	115	72	37
3∅ 336.4 ACSR (18/1)	553	436	333	245	169	106	55	431	339	259	191	132	83	43	353	278	212	156	108	68	35
3∅ 477.0 ACSR (18/1)	502	395	302	222	154	97	50	399	314	240	177	122	77	40	331	261	199	147	101	64	33

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,409	1,083	799	553	344	169	26	802	617	455	315	196	96	15	561	431	318	220	137	67	10
1∅ 1/O ACSR (6/1)	1,224	941	694	481	299	147	22	739	568	419	290	180	89	13	529	407	300	208	129	64	10
1∅ 4/O ACSR (6/1)	1,061	816	601	417	259	127	19	676	520	383	265	165	81	12	496	381	281	195	121	60	9
1∅ 336.4 ACSR (18/1)	967	743	548	380	236	116	18	637	489	361	250	155	76	12	474	365	269	186	116	57	9
1∅ 477.0 ACSR (18/1)	883	678	500	346	216	106	16	599	460	339	235	146	72	11	453	348	257	178	111	54	8
3∅ 4 ACSR (7/1)	766	589	434	301	187	92	14	543	417	308	213	133	65	10	420	323	238	165	103	50	8
3∅ 1/O ACSR (6/1)	657	505	372	258	160	79	12	485	373	275	191	119	58	9	385	296	218	151	94	46	7
3∅ 4/O ACSR (6/1)	562	432	319	221	137	68	10	432	332	245	170	105	52	8	351	270	199	138	86	42	6
3∅ 336.4 ACSR (18/1)	509	391	288	200	124	61	9	400	307	226	157	98	48	7	329	253	186	129	80	40	6
3∅ 477.0 ACSR (18/1)	462	355	262	181	113	55	8	370	284	210	145	90	44	7	309	237	175	121	75	37	6

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	835	660	507	375	263	169	91	576	455	349	258	181	116	63	439	347	267	197	138	89	48
3∅ 1/O ACSR (6/1)	717	566	435	322	225	145	78	517	408	314	232	163	104	57	404	319	245	181	127	82	44
3∅ 4/O ACSR (6/1)	615	486	373	276	193	124	67	462	365	280	207	145	93	51	369	292	224	166	116	75	40
3∅ 336.4 ACSR (18/1)	557	440	338	250	175	112	61	428	338	260	192	135	86	47	348	275	211	156	109	70	38
3∅ 477.0 ACSR (18/1)	505	399	307	227	159	102	55	397	314	241	178	125	80	43	327	258	198	147	103	66	36

NESC Extreme Wind (150 mph) - Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	694	518	363	231	117	23	-	486	363	255	162	82	16	-	374	279	196	124	63	12	-
3∅ 1/O ACSR (6/1)	595	444	312	198	101	19	-	436	325	228	145	74	14	-	344	256	180	114	58	11	-
3∅ 4/O ACSR (6/1)	510	380	267	169	86	17	-	388	289	203	129	66	13	-	313	234	164	104	53	10	-
3∅ 336.4 ACSR (18/1)	462	344	242	153	78	15	-	359	268	188	119	61	12	-	294	219	154	98	50	10	-
3∅ 477.0 ACSR (18/1)	419	312	219	139	71	14	-	333	248	174	111	56	11	-	276	206	145	92	47	9	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	491	314	159	26	-	-	-	348	222	113	18	-	-	-	270	172	87	14	-	-	-
3∅ 1/O ACSR (6/1)	421	269	136	22	-	-	-	311	199	101	16	-	-	-	247	158	80	13	-	-	-
3∅ 4/O ACSR (6/1)	361	230	117	19	-	-	-	277	177	90	15	-	-	-	225	144	73	12	-	-	-
3∅ 336.4 ACSR (18/1)	326	208	106	17	-	-	-	256	164	83	13	-	-	-	211	135	68	11	-	-	-
3∅ 477.0 ACSR (18/1)	296	189	96	16	-	-	-	237	152	77	12	-	-	-	198	126	64	10	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	799	620	465	330	216	120	41	576	447	335	238	156	87	30	451	350	262	186	122	68	23
3∅ 1/O ACSR (6/1)	684	531	398	283	185	103	35	514	399	299	212	139	77	27	412	320	239	170	111	62	21
3∅ 4/O ACSR (6/1)	585	454	340	242	158	88	30	456	354	265	188	123	68	24	374	290	217	154	101	56	19
3∅ 336.4 ACSR (18/1)	529	411	308	219	143	79	27	421	327	245	174	114	63	22	350	272	204	145	95	53	18
3∅ 477.0 ACSR (18/1)	480	373	279	198	130	72	25	389	302	226	161	105	58	20	328	254	191	135	89	49	17

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	766	589	434	300	186	91	13	546	419	309	214	133	65	9	424	325	240	166	103	50	7
3∅ 1/O ACSR (6/1)	657	504	372	257	160	78	11	488	375	276	191	118	58	8	388	298	219	152	94	46	6
3∅ 4/O ACSR (6/1)	562	432	318	220	137	67	9	434	333	245	170	105	51	7	353	271	200	138	86	42	6
3∅ 336.4 ACSR (18/1)	509	391	288	199	124	60	8	401	308	227	157	97	48	7	331	254	187	130	80	39	5
3∅ 477.0 ACSR (18/1)	461	354	261	181	112	55	8	371	285	210	145	90	44	6	310	238	176	121	75	37	5

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	701	523	367	233	118	23	-	504	376	264	167	85	16	-	394	294	206	131	67	13	-
3∅ 1/O ACSR (6/1)	600	447	314	199	101	19	-	450	335	236	149	76	15	-	360	268	188	119	61	12	-
3∅ 4/O ACSR (6/1)	514	383	269	171	87	17	-	400	298	209	133	67	13	-	327	244	171	109	55	11	-
3∅ 336.4 ACSR (18/1)	465	346	243	154	78	15	-	369	275	193	123	62	12	-	306	228	160	102	52	10	-
3∅ 477.0 ACSR (18/1)	421	314	221	140	71	14	-	341	254	179	113	58	11	-	287	214	150	95	48	9	-

NESC Extreme Wind (150 mph) - Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,580	2,099	1,678	1,313	1,001	737	518	1,385	1,127	901	705	537	396	278	947	770	616	482	367	270	190
1∅ 1/O ACSR (6/1)	2,251	1,832	1,464	1,146	873	643	452	1,284	1,045	835	654	498	367	258	898	731	584	457	348	257	181
1∅ 4/O ACSR (6/1)	1,959	1,594	1,274	997	760	560	394	1,184	963	770	602	459	338	238	848	690	552	432	329	242	170
1∅ 336.4 ACSR (18/1)	1,789	1,455	1,163	910	694	511	359	1,119	911	728	570	434	320	225	814	663	530	415	316	233	164
1∅ 477.0 ACSR (18/1)	1,636	1,331	1,064	833	634	467	329	1,057	860	688	538	410	302	212	781	636	508	398	303	223	157
3∅ 4 ACSR (7/1)	1,424	1,159	926	725	552	407	286	965	785	628	491	374	276	194	729	594	474	371	283	208	147
3∅ 1/O ACSR (6/1)	1,224	996	796	623	475	350	246	868	707	565	442	337	248	174	673	548	438	342	261	192	135
3∅ 4/O ACSR (6/1)	1,050	855	683	535	407	300	211	777	632	506	396	301	222	156	617	502	401	314	239	176	124
3∅ 336.4 ACSR (18/1)	952	774	619	484	369	272	191	722	587	470	367	280	206	145	582	473	378	296	226	166	117
3∅ 477.0 ACSR (18/1)	864	703	562	440	335	247	174	670	546	436	341	260	192	135	548	446	356	279	212	156	110

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,570	2,083	1,656	1,287	970	703	482	1,410	1,143	909	706	532	386	264	972	788	626	487	367	266	182
1∅ 1/O ACSR (6/1)	2,239	1,814	1,443	1,121	845	612	420	1,304	1,057	841	653	492	357	244	920	746	593	461	347	252	172
1∅ 4/O ACSR (6/1)	1,945	1,577	1,254	974	734	532	365	1,199	972	773	600	453	328	225	867	702	559	434	327	237	162
1∅ 336.4 ACSR (18/1)	1,775	1,438	1,144	888	670	485	333	1,132	917	730	567	427	310	212	831	674	536	416	314	227	156
1∅ 477.0 ACSR (18/1)	1,622	1,314	1,045	812	612	444	304	1,068	865	688	535	403	292	200	796	645	513	398	300	218	149
3∅ 4 ACSR (7/1)	1,411	1,143	909	706	532	386	264	972	788	626	487	367	266	182	741	601	478	371	280	203	139
3∅ 1/O ACSR (6/1)	1,211	981	780	606	457	331	227	873	707	562	437	329	239	164	682	553	440	342	257	187	128
3∅ 4/O ACSR (6/1)	1,038	842	669	520	392	284	195	779	632	502	390	294	213	146	624	506	402	312	235	171	117
3∅ 336.4 ACSR (18/1)	940	762	606	471	355	257	176	723	586	466	362	273	198	135	587	476	378	294	222	161	110
3∅ 477.0 ACSR (18/1)	854	692	550	427	322	233	160	670	543	432	336	253	183	126	552	447	356	276	208	151	103

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,485	1,991	1,559	1,185	864	594	370	1,394	1,117	875	665	485	333	208	969	776	608	462	337	232	144
1∅ 1/O ACSR (6/1)	2,161	1,732	1,356	1,031	752	517	322	1,286	1,031	807	613	447	307	191	915	734	574	437	318	219	136
1∅ 4/O ACSR (6/1)	1,875	1,503	1,177	894	652	448	279	1,179	945	740	562	410	282	176	860	689	540	410	299	206	128
1∅ 336.4 ACSR (18/1)	1,709	1,370	1,073	815	595	409	254	1,111	891	697	530	387	266	165	823	660	517	393	286	197	123
1∅ 477.0 ACSR (18/1)	1,561	1,251	980	744	543	373	232	1,046	839	657	499	364	250	156	787	631	494	375	274	188	117
3∅ 4 ACSR (7/1)	1,356	1,087	851	647	472	324	202	950	762	596	453	331	227	141	731	586	459	349	254	175	109
3∅ 1/O ACSR (6/1)	1,163	932	730	555	405	278	173	851	682	534	406	296	203	127	671	538	421	320	234	160	100
3∅ 4/O ACSR (6/1)	996	799	625	475	347	238	148	758	608	476	362	264	181	113	612	491	384	292	213	146	91
3∅ 336.4 ACSR (18/1)	902	723	566	430	314	216	134	702	563	441	335	244	168	105	575	461	361	274	200	138	86
3∅ 477.0 ACSR (18/1)	818	656	514	390	285	196	122	651	521	408	310	226	156	97	540	433	339	258	188	129	80

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	2,330	1,833	1,397	1,020	697	424	198	1,327	1,043	796	581	397	242	113	927	729	556	406	277	169	79
1∅ 1/O ACSR (6/1)	2,024	1,592	1,214	886	605	369	172	1,221	961	733	535	365	222	104	875	688	525	383	262	159	74
1∅ 4/O ACSR (6/1)	1,755	1,380	1,052	768	525	320	149	1,118	879	670	489	334	204	95	820	645	492	359	245	149	70
1∅ 336.4 ACSR (18/1)	1,599	1,258	959	700	478	291	136	1,052	828	631	461	315	192	90	784	617	470	343	235	143	67
1∅ 477.0 ACSR (18/1)	1,459	1,148	875	639	436	266	124	990	779	594	433	296	180	84	749	589	449	328	224	136	64
3∅ 4 ACSR (7/1)	1,267	997	760	555	379	231	108	898	706	538	393	269	163	76	695	547	417	304	208	127	59
3∅ 1/O ACSR (6/1)	1,086	854	651	475	325	198	92	803	631	481	351	240	146	68	637	501	382	279	190	116	54
3∅ 4/O ACSR (6/1)	930	731	558	407	278	169	79	714	562	428	313	214	130	61	580	456	348	254	173	106	49
3∅ 336.4 ACSR (18/1)	841	662	505	368	252	153	72	661	520	396	289	198	120	56	544	428	326	238	163	99	46
3∅ 477.0 ACSR (18/1)	763	600	458	334	228	139	65	612	481	367	268	183	111	52	510	401	306	223	153	93	43

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,363	1,095	861	658	485	338	217	939	755	593	454	334	233	149	716	576	453	346	255	178	114
3∅ 1/O ACSR (6/1)	1,170	940	739	565	416	290	186	843	678	533	407	300	209	134	659	530	417	318	234	163	105
3∅ 4/O ACSR (6/1)	1,003	806	634	485	357	249	159	753	605	476	364	268	187	120	603	484	381	291	214	149	96
3∅ 336.4 ACSR (18/1)	908	730	574	439	323	225	144	698	561	441	337	248	173	111	567	456	358	274	202	141	90
3∅ 477.0 ACSR (18/1)	825	663	521	398	293	205	131	648	521	409	313	230	161	103	533	429	337	258	190	132	85

NESC Extreme Wind (150 mph) - Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,179	910	674	470	295	148	25	827	638	473	329	207	103	18	636	491	364	254	159	80	14
3∅ 1/O ACSR (6/1)	1,011	780	578	403	253	127	22	740	571	423	295	185	93	16	584	451	334	233	146	73	13
3∅ 4/O ACSR (6/1)	867	669	496	345	217	108	19	660	509	377	263	165	83	14	532	411	304	212	133	67	11
3∅ 336.4 ACSR (18/1)	784	605	449	313	196	98	17	611	471	349	243	153	76	13	500	386	286	199	125	63	11
3∅ 477.0 ACSR (18/1)	712	549	407	284	178	89	15	566	437	324	226	142	71	12	470	362	269	187	118	59	10

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	900	629	393	187	12	-	-	638	446	278	133	8	-	-	494	345	215	103	6	-	-
3∅ 1/O ACSR (6/1)	771	539	336	161	10	-	-	570	399	249	119	7	-	-	452	316	197	94	6	-	-
3∅ 4/O ACSR (6/1)	660	462	288	138	9	-	-	507	355	221	106	7	-	-	412	288	180	86	5	-	-
3∅ 336.4 ACSR (18/1)	597	418	261	124	8	-	-	469	328	205	98	6	-	-	386	270	169	80	5	-	-
3∅ 477.0 ACSR (18/1)	542	379	237	113	7	-	-	434	304	190	90	6	-	-	362	254	158	75	5	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,314	1,041	803	596	419	270	146	947	751	579	430	302	195	106	741	587	453	336	237	152	83
3∅ 1/O ACSR (6/1)	1,124	891	687	510	359	231	125	845	670	516	384	270	174	94	677	536	414	307	216	139	75
3∅ 4/O ACSR (6/1)	962	763	588	437	307	198	107	750	595	458	340	239	154	84	614	487	376	279	196	126	68
3∅ 336.4 ACSR (18/1)	870	690	532	395	278	179	97	693	549	424	315	221	142	77	576	456	352	261	184	118	64
3∅ 477.0 ACSR (18/1)	789	626	482	358	252	162	88	640	508	391	291	204	132	71	539	427	329	245	172	111	60

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,268	998	760	555	379	230	107	903	710	541	395	270	164	76	701	551	420	307	209	127	59
3∅ 1/O ACSR (6/1)	1,087	854	651	475	324	197	92	807	635	484	353	241	146	68	642	505	385	281	192	116	54
3∅ 4/O ACSR (6/1)	930	732	558	407	278	169	79	717	564	430	314	214	130	61	584	459	350	255	174	106	49
3∅ 336.4 ACSR (18/1)	842	662	505	368	251	153	71	664	522	398	290	198	120	56	548	431	328	239	163	99	46
3∅ 477.0 ACSR (18/1)	763	600	458	334	228	139	64	614	483	368	268	183	111	52	513	404	308	225	153	93	43

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,177	905	667	461	284	135	11	847	651	480	331	204	97	8	661	509	375	259	159	76	6
3∅ 1/O ACSR (6/1)	1,008	775	571	394	243	115	10	756	581	428	296	182	86	7	604	465	342	236	146	69	6
3∅ 4/O ACSR (6/1)	863	663	489	338	208	99	8	671	516	380	263	162	77	6	549	422	311	215	132	63	5
3∅ 336.4 ACSR (18/1)	780	600	442	305	188	89	7	620	477	351	243	149	71	6	514	395	291	201	124	59	5
3∅ 477.0 ACSR (18/1)	707	544	401	277	171	81	7	573	441	325	224	138	66	5	482	370	273	188	116	55	5

NESC Extreme Wind (90 mph) - Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,134	939	767	617	487	376	283	757	627	512	412	325	251	189	568	470	384	309	244	188	142
1∅ 1/O ACSR (6/1)	1,041	861	703	565	445	344	258	713	590	482	387	305	235	177	543	449	367	295	232	179	134
1∅ 4/O ACSR (6/1)	954	790	644	518	408	315	236	672	556	454	364	287	222	166	518	429	350	281	222	171	128
1∅ 336.4 ACSR (18/1)	899	744	607	488	385	297	223	644	533	435	349	276	213	159	502	415	339	272	215	166	124
1∅ 477.0 ACSR (18/1)	847	701	572	460	362	279	210	617	510	416	335	264	204	153	485	401	327	263	207	160	120
3∅ 4 ACSR (7/1)	635	526	429	345	272	210	157	496	411	335	269	212	164	123	407	337	275	221	174	134	101
3∅ 1/O ACSR (6/1)	579	479	391	314	248	191	143	461	382	312	250	197	152	114	383	317	259	208	164	127	95
3∅ 4/O ACSR (6/1)	525	435	355	285	225	173	130	426	353	288	231	182	141	106	359	297	242	195	154	118	89
3∅ 336.4 ACSR (18/1)	492	407	332	267	210	162	122	404	334	273	219	173	133	100	343	284	232	186	147	113	85
3∅ 477.0 ACSR (18/1)	460	381	311	250	197	152	114	382	316	258	207	164	126	95	327	271	221	178	140	108	81

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,125	927	753	601	470	358	263	763	629	511	407	318	242	178	577	475	386	308	241	183	135
1∅ 1/O ACSR (6/1)	1,036	854	694	554	433	329	242	721	594	483	385	301	229	169	553	455	370	295	231	176	129
1∅ 4/O ACSR (6/1)	949	782	635	507	396	302	222	677	558	453	362	283	215	158	527	434	353	281	220	167	123
1∅ 336.4 ACSR (18/1)	894	737	598	477	373	284	209	649	535	434	347	271	206	152	509	420	341	272	213	162	119
1∅ 477.0 ACSR (18/1)	841	693	563	449	351	267	197	621	511	415	332	259	197	145	492	405	329	263	205	156	115
3∅ 4 ACSR (7/1)	629	518	421	336	263	200	147	497	410	333	266	207	158	116	411	339	275	219	171	131	96
3∅ 1/O ACSR (6/1)	573	472	384	306	239	182	134	461	380	309	247	193	147	108	386	318	259	206	161	123	90
3∅ 4/O ACSR (6/1)	519	428	348	277	217	165	121	426	351	285	228	178	135	100	361	298	242	193	151	115	84
3∅ 336.4 ACSR (18/1)	486	400	325	260	203	154	114	403	332	270	215	168	128	94	344	284	231	184	144	109	81
3∅ 477.0 ACSR (18/1)	454	375	304	243	190	144	106	381	314	255	204	159	121	89	328	271	220	175	137	104	77

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,089	889	712	558	424	311	215	750	612	490	384	292	214	148	572	466	374	293	223	163	113
1∅ 1/O ACSR (6/1)	1,002	818	655	513	391	286	198	707	577	462	362	276	202	140	547	446	357	280	213	156	108
1∅ 4/O ACSR (6/1)	917	748	599	469	357	261	181	664	541	434	340	259	189	131	520	424	340	266	203	148	103
1∅ 336.4 ACSR (18/1)	863	704	564	442	336	246	170	635	518	415	325	247	181	125	502	410	328	257	196	143	99
1∅ 477.0 ACSR (18/1)	811	662	530	415	316	231	160	607	495	397	311	236	173	120	484	395	317	248	189	138	96
3∅ 4 ACSR (7/1)	605	494	396	310	236	173	119	483	394	316	248	188	138	95	403	328	263	206	157	115	79
3∅ 1/O ACSR (6/1)	551	450	360	282	215	157	109	448	366	293	230	175	128	88	378	308	247	193	147	108	75
3∅ 4/O ACSR (6/1)	499	407	326	255	194	142	98	413	337	270	212	161	118	82	353	288	230	181	137	101	70
3∅ 336.4 ACSR (18/1)	467	381	305	239	182	133	92	391	319	255	200	152	111	77	336	274	220	172	131	96	66
3∅ 477.0 ACSR (18/1)	436	356	285	223	170	124	86	369	301	241	189	144	105	73	320	261	209	164	125	91	63

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,026	824	645	490	355	240	144	713	573	449	340	247	167	100	547	439	344	261	189	128	77
1∅ 1/O ACSR (6/1)	944	757	593	450	326	221	132	672	540	423	321	233	157	94	522	419	328	249	181	122	73
1∅ 4/O ACSR (6/1)	862	692	542	411	298	202	121	630	506	396	301	218	148	88	496	398	312	237	172	116	69
1∅ 336.4 ACSR (18/1)	811	651	510	387	281	190	114	602	483	379	287	208	141	84	479	384	301	229	166	112	67
1∅ 477.0 ACSR (18/1)	762	612	479	364	264	178	107	575	462	362	274	199	135	80	462	370	290	220	160	108	65
3∅ 4 ACSR (7/1)	568	456	357	271	196	133	79	457	367	287	218	158	107	64	382	307	240	182	132	89	53
3∅ 1/O ACSR (6/1)	517	415	325	247	179	121	72	423	340	266	202	146	99	59	358	288	225	171	124	84	50
3∅ 4/O ACSR (6/1)	468	375	294	223	162	109	65	390	313	245	186	135	91	55	334	268	210	159	116	78	47
3∅ 336.4 ACSR (18/1)	437	351	275	209	151	102	61	368	296	232	176	127	86	52	318	255	200	152	110	75	45
3∅ 477.0 ACSR (18/1)	409	328	257	195	141	96	57	348	279	219	166	120	81	49	303	243	190	144	105	71	42

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	606	495	398	313	240	177	124	479	391	314	247	189	140	98	396	324	260	204	156	115	81
3∅ 1/O ACSR (6/1)	552	451	363	285	218	161	113	445	363	292	230	176	130	91	372	304	244	192	147	109	76
3∅ 4/O ACSR (6/1)	500	409	329	258	198	146	102	410	335	270	212	162	120	84	348	284	228	180	137	102	71
3∅ 336.4 ACSR (18/1)	468	383	307	242	185	137	96	388	318	255	201	154	113	80	332	271	218	171	131	97	68
3∅ 477.0 ACSR (18/1)	438	358	288	226	173	128	90	367	300	241	190	145	107	75	316	259	208	163	125	92	65

NESC Extreme Wind (90 mph) - Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	524	413	315	229	155	92	38	419	330	251	183	124	73	31	349	275	209	152	103	61	26
3∅ 1/O ACSR (6/1)	477	376	286	208	141	83	35	388	306	233	170	115	68	28	327	258	196	143	97	57	24
3∅ 4/O ACSR (6/1)	432	340	259	189	128	76	32	358	282	215	156	106	63	26	305	241	183	133	90	53	22
3∅ 336.4 ACSR (18/1)	404	318	243	176	119	71	30	338	267	203	148	100	59	25	291	229	175	127	86	51	21
3∅ 477.0 ACSR (18/1)	378	297	227	165	112	66	28	320	252	192	140	94	56	23	277	218	166	121	82	48	20

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	405	293	195	109	34	-	-	326	236	157	87	28	-	-	273	198	131	73	23	-	-
3∅ 1/O ACSR (6/1)	369	267	177	99	31	-	-	302	219	145	81	26	-	-	256	185	123	69	22	-	-
3∅ 4/O ACSR (6/1)	334	242	160	90	28	-	-	278	201	134	75	23	-	-	239	173	115	64	20	-	-
3∅ 336.4 ACSR (18/1)	312	226	150	84	26	-	-	263	190	126	70	22	-	-	227	165	109	61	19	-	-
3∅ 477.0 ACSR (18/1)	292	211	140	78	25	-	-	248	180	119	67	21	-	-	216	157	104	58	18	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	588	476	376	289	214	150	96	479	387	306	235	174	122	78	404	326	258	199	147	103	66
3∅ 1/O ACSR (6/1)	535	433	342	263	195	137	88	443	358	283	218	161	113	72	378	306	242	186	138	96	62
3∅ 4/O ACSR (6/1)	484	391	309	238	176	123	79	408	329	260	200	148	104	67	352	284	225	173	128	90	58
3∅ 336.4 ACSR (18/1)	452	366	289	222	165	115	74	385	311	246	189	140	98	63	335	271	214	165	122	85	55
3∅ 477.0 ACSR (18/1)	423	341	270	208	154	108	69	363	293	232	178	132	93	59	318	257	203	156	116	81	52

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	568	456	357	271	196	132	79	459	368	288	219	158	107	64	385	309	242	183	133	90	53
3∅ 1/O ACSR (6/1)	517	415	325	246	178	121	72	425	341	267	202	147	99	59	360	289	227	172	124	84	50
3∅ 4/O ACSR (6/1)	468	375	294	223	161	109	65	391	314	246	186	135	91	54	336	269	211	160	116	78	47
3∅ 336.4 ACSR (18/1)	437	351	275	208	151	102	61	369	296	232	176	128	86	51	320	257	201	152	110	75	44
3∅ 477.0 ACSR (18/1)	409	328	257	195	141	95	57	349	280	219	166	120	81	48	304	244	191	145	105	71	42

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	530	418	318	232	157	93	39	431	339	259	188	127	75	32	363	286	218	159	107	63	27
3∅ 1/O ACSR (6/1)	483	380	290	211	142	84	35	399	314	239	174	118	70	29	340	268	204	148	100	59	25
3∅ 4/O ACSR (6/1)	436	344	262	190	129	76	32	367	289	220	160	108	64	27	317	249	190	138	93	55	23
3∅ 336.4 ACSR (18/1)	408	321	245	178	120	71	30	346	273	208	151	102	60	25	301	237	181	131	89	53	22
3∅ 477.0 ACSR (18/1)	381	300	229	166	112	67	28	327	257	196	143	97	57	24	286	225	172	125	85	50	21

NESC Extreme Wind (90 mph) - Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,717	1,425	1,167	942	747	580	440	1,146	951	779	629	499	388	294	860	714	585	472	374	291	220
1∅ 1/O ACSR (6/1)	1,583	1,314	1,077	869	689	535	406	1,085	901	738	596	472	367	278	826	685	561	453	359	279	211
1∅ 4/O ACSR (6/1)	1,451	1,205	987	796	632	491	372	1,022	848	695	561	445	345	262	788	654	536	433	343	266	202
1∅ 336.4 ACSR (18/1)	1,368	1,135	930	751	595	462	350	979	813	666	537	426	331	251	763	633	519	419	332	258	195
1∅ 477.0 ACSR (18/1)	1,288	1,069	876	707	561	436	330	938	778	638	515	408	317	240	737	612	501	405	321	249	189
3∅ 4 ACSR (7/1)	966	802	657	530	420	327	247	755	626	513	414	328	255	193	619	514	421	340	270	209	159
3∅ 1/O ACSR (6/1)	881	731	599	484	383	298	226	702	582	477	385	305	237	180	583	484	397	320	254	197	149
3∅ 4/O ACSR (6/1)	799	663	543	438	348	270	205	649	538	441	356	282	219	166	546	453	371	300	238	185	140
3∅ 336.4 ACSR (18/1)	748	621	508	410	325	253	192	615	510	418	337	267	208	157	522	433	355	286	227	176	134
3∅ 477.0 ACSR (18/1)	700	581	476	384	304	237	179	582	483	395	319	253	197	149	498	413	338	273	217	168	127

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,717	1,421	1,160	931	733	564	421	1,164	963	786	631	497	382	286	881	729	595	477	376	289	216
1∅ 1/O ACSR (6/1)	1,582	1,309	1,068	858	675	520	388	1,100	910	743	597	470	361	270	844	698	570	457	360	277	207
1∅ 4/O ACSR (6/1)	1,449	1,199	978	785	618	476	355	1,034	856	698	561	441	340	254	804	665	543	436	343	264	197
1∅ 336.4 ACSR (18/1)	1,364	1,129	921	740	582	448	335	990	819	669	537	423	325	243	777	643	525	421	332	255	191
1∅ 477.0 ACSR (18/1)	1,284	1,062	867	696	548	422	315	947	784	640	514	404	311	232	751	621	507	407	320	246	184
3∅ 4 ACSR (7/1)	960	794	648	521	410	315	235	759	628	512	411	324	249	186	627	519	423	340	268	206	154
3∅ 1/O ACSR (6/1)	875	724	591	474	374	287	215	704	583	476	382	301	231	173	590	488	398	320	252	194	145
3∅ 4/O ACSR (6/1)	793	656	535	430	338	260	194	650	538	439	352	278	214	159	551	456	372	299	235	181	135
3∅ 336.4 ACSR (18/1)	742	614	501	402	317	244	182	615	509	416	334	263	202	151	526	435	355	285	225	173	129
3∅ 477.0 ACSR (18/1)	694	574	468	376	296	228	170	582	481	393	315	248	191	143	501	415	338	272	214	165	123

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,674	1,373	1,108	876	676	504	359	1,152	945	763	603	465	347	247	878	721	581	460	355	264	188
1∅ 1/O ACSR (6/1)	1,540	1,264	1,020	806	622	464	330	1,087	892	720	569	439	327	233	840	689	556	440	339	253	180
1∅ 4/O ACSR (6/1)	1,409	1,156	933	738	569	424	302	1,020	837	675	534	412	307	219	799	656	529	418	323	241	171
1∅ 336.4 ACSR (18/1)	1,326	1,088	878	694	535	399	284	976	800	646	511	394	294	209	772	633	511	404	312	232	166
1∅ 477.0 ACSR (18/1)	1,247	1,023	825	653	503	375	267	932	765	617	488	376	281	200	744	611	493	390	300	224	160
3∅ 4 ACSR (7/1)	930	763	616	487	375	280	200	743	610	492	389	300	224	159	619	508	410	324	250	186	133
3∅ 1/O ACSR (6/1)	847	695	561	443	342	255	182	689	565	456	361	278	207	148	581	476	384	304	234	175	125
3∅ 4/O ACSR (6/1)	767	629	508	401	310	231	165	635	521	420	332	256	191	136	542	445	359	284	219	163	116
3∅ 336.4 ACSR (18/1)	717	588	475	375	289	216	154	601	493	398	314	242	181	129	517	424	342	270	209	156	111
3∅ 477.0 ACSR (18/1)	670	550	444	351	271	202	144	567	465	376	297	229	171	122	492	404	326	257	199	148	106

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,589	1,285	1,017	783	581	408	261	1,104	893	707	545	404	283	182	846	685	542	417	309	217	139
1∅ 1/O ACSR (6/1)	1,461	1,182	935	720	534	375	240	1,041	842	667	513	381	267	171	809	654	518	399	296	207	133
1∅ 4/O ACSR (6/1)	1,335	1,080	855	658	488	342	220	975	789	625	481	357	250	160	768	622	492	379	281	197	126
1∅ 336.4 ACSR (18/1)	1,256	1,016	804	619	459	322	207	932	754	597	460	341	239	153	741	600	475	366	271	190	122
1∅ 477.0 ACSR (18/1)	1,180	955	756	582	432	303	194	890	720	570	439	325	228	146	715	578	458	352	261	183	118
3∅ 4 ACSR (7/1)	879	711	563	433	321	225	145	707	572	453	349	259	181	116	592	479	379	292	216	152	97
3∅ 1/O ACSR (6/1)	800	647	512	394	292	205	132	655	530	420	323	240	168	108	555	449	355	274	203	142	91
3∅ 4/O ACSR (6/1)	724	586	464	357	265	186	119	603	488	386	298	221	155	99	517	418	331	255	189	133	85
3∅ 336.4 ACSR (18/1)	677	547	433	334	247	174	111	570	461	365	281	208	146	94	493	399	316	243	180	126	81
3∅ 477.0 ACSR (18/1)	633	512	405	312	231	162	104	538	436	345	266	197	138	89	469	379	300	231	171	120	77

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	932	766	620	492	382	287	207	736	605	490	389	302	227	164	609	500	405	322	249	188	135
3∅ 1/O ACSR (6/1)	849	698	565	449	348	262	189	684	562	455	361	280	211	152	572	471	381	302	234	176	127
3∅ 4/O ACSR (6/1)	770	633	512	407	315	237	171	631	519	420	333	259	194	140	535	440	356	283	219	165	119
3∅ 336.4 ACSR (18/1)	720	592	479	380	295	222	160	597	491	397	316	245	184	133	510	420	340	270	209	157	114
3∅ 477.0 ACSR (18/1)	673	554	448	356	276	207	150	565	464	376	298	231	174	126	487	400	324	257	199	150	108

NESC Extreme Wind (90 mph) - Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	826	659	512	383	271	176	95	660	526	409	306	217	141	76	549	438	340	255	180	117	63
3∅ 1/O ACSR (6/1)	752	600	466	349	247	160	87	612	488	379	284	201	130	71	516	411	319	239	169	110	60
3∅ 4/O ACSR (6/1)	681	543	422	316	224	145	79	564	450	349	261	185	120	65	481	384	298	223	158	102	56
3∅ 336.4 ACSR (18/1)	637	508	394	295	209	136	74	533	425	330	247	175	114	62	459	366	284	213	151	98	53
3∅ 477.0 ACSR (18/1)	595	475	369	276	196	127	69	504	402	312	234	166	107	58	437	348	271	202	143	93	50

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	662	494	346	217	105	9	-	533	398	279	174	84	7	-	446	333	233	146	70	6	-
3∅ 1/O ACSR (6/1)	603	450	315	197	95	8	-	494	369	258	162	78	7	-	418	312	219	137	66	6	-
3∅ 4/O ACSR (6/1)	546	407	285	179	86	7	-	455	339	238	149	72	6	-	390	291	204	128	62	5	-
3∅ 336.4 ACSR (18/1)	510	381	267	167	81	7	-	430	321	225	141	68	6	-	371	277	194	122	59	5	-
3∅ 477.0 ACSR (18/1)	477	356	249	156	75	6	-	406	303	212	133	64	5	-	353	264	185	116	56	5	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	908	739	590	459	346	250	168	740	602	480	374	282	203	137	624	507	405	315	238	171	115
3∅ 1/O ACSR (6/1)	826	672	536	418	315	227	153	684	557	444	346	261	188	127	584	475	379	295	223	160	108
3∅ 4/O ACSR (6/1)	747	608	485	378	285	205	138	629	512	408	318	240	173	116	543	442	353	275	207	149	101
3∅ 336.4 ACSR (18/1)	698	568	453	353	266	192	129	594	483	386	300	226	163	110	517	421	336	261	197	142	96
3∅ 477.0 ACSR (18/1)	652	531	424	330	249	179	121	560	456	364	283	214	154	104	491	400	319	248	187	135	91

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	880	712	563	434	321	225	144	711	575	455	350	259	182	116	596	482	381	294	218	153	98
3∅ 1/O ACSR (6/1)	801	648	513	395	293	205	131	658	532	421	324	240	168	108	558	452	357	275	204	143	92
3∅ 4/O ACSR (6/1)	725	586	464	357	265	186	119	606	490	388	298	221	155	99	520	421	333	256	190	133	85
3∅ 336.4 ACSR (18/1)	677	548	434	334	247	173	111	572	463	366	282	209	147	94	495	401	317	244	181	127	81
3∅ 477.0 ACSR (18/1)	633	512	405	312	231	162	104	540	437	346	266	197	138	89	471	381	302	232	172	121	77

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	828	658	509	379	266	170	88	673	535	414	308	216	138	72	567	451	349	259	182	116	60
3∅ 1/O ACSR (6/1)	753	599	463	345	242	154	80	622	495	383	285	200	128	66	531	422	327	243	171	109	56
3∅ 4/O ACSR (6/1)	681	542	419	312	219	139	72	572	455	352	262	184	117	61	494	393	304	226	159	101	53
3∅ 336.4 ACSR (18/1)	636	506	392	291	205	130	68	541	430	333	248	174	111	58	470	374	289	215	151	96	50
3∅ 477.0 ACSR (18/1)	594	473	366	272	191	122	63	510	406	314	234	164	105	54	447	355	275	205	144	92	48

NESC Extreme Wind (120 mph) - Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,050	860	693	549	424	319	231	701	574	463	366	283	213	154	526	431	347	275	213	160	116
1∅ 1/O ACSR (6/1)	960	785	632	499	385	288	208	658	538	433	342	264	198	142	500	409	330	260	201	150	108
1∅ 4/O ACSR (6/1)	880	720	580	458	353	264	191	619	507	408	322	248	186	134	478	391	315	249	192	144	103
1∅ 336.4 ACSR (18/1)	829	678	546	431	333	249	180	594	486	391	309	238	178	129	462	378	305	241	186	139	100
1∅ 477.0 ACSR (18/1)	781	639	514	406	313	235	169	569	465	375	296	228	171	123	447	366	294	233	179	134	97
3∅ 4 ACSR (7/1)	586	479	386	305	235	176	127	457	374	301	238	184	137	99	375	307	247	195	151	113	81
3∅ 1/O ACSR (6/1)	534	437	352	278	214	160	116	425	348	280	221	171	128	92	354	289	233	184	142	106	77
3∅ 4/O ACSR (6/1)	484	396	319	252	194	145	105	393	322	259	205	158	118	85	331	271	218	172	133	99	72
3∅ 336.4 ACSR (18/1)	453	371	299	236	182	136	98	372	305	245	194	149	112	81	316	259	208	164	127	95	68
3∅ 477.0 ACSR (18/1)	424	347	279	221	170	127	92	353	288	232	183	141	106	76	302	247	199	157	121	91	65

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,036	844	675	529	403	297	208	702	572	458	359	273	201	141	531	433	346	271	207	152	107
1∅ 1/O ACSR (6/1)	954	777	622	487	371	273	192	664	541	433	339	258	190	133	509	414	332	260	198	146	102
1∅ 4/O ACSR (6/1)	874	712	570	446	340	250	176	624	508	407	318	243	179	125	485	395	316	248	189	139	97
1∅ 336.4 ACSR (18/1)	823	670	536	420	320	236	165	597	487	389	305	233	171	120	469	382	306	239	183	134	94
1∅ 477.0 ACSR (18/1)	774	631	505	395	301	222	156	571	465	372	292	222	164	115	453	369	295	231	176	130	91
3∅ 4 ACSR (7/1)	579	472	377	296	225	166	116	457	373	298	234	178	131	92	378	308	247	193	147	108	76
3∅ 1/O ACSR (6/1)	528	430	344	269	205	151	106	425	346	277	217	165	122	85	356	290	232	182	138	102	71
3∅ 4/O ACSR (6/1)	478	389	312	244	186	137	96	392	319	256	200	153	112	79	332	271	217	170	129	95	67
3∅ 336.4 ACSR (18/1)	447	364	292	228	174	128	90	371	302	242	190	144	106	75	317	258	207	162	123	91	64
3∅ 477.0 ACSR (18/1)	418	341	273	214	163	120	84	351	286	229	179	137	101	71	302	246	197	154	118	87	61

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	999	804	633	485	357	249	159	687	553	436	333	246	171	110	524	422	332	254	187	131	84
1∅ 1/O ACSR (6/1)	919	740	582	446	329	229	146	649	522	411	315	232	162	103	501	403	318	243	179	125	80
1∅ 4/O ACSR (6/1)	840	677	533	408	300	210	134	608	490	386	295	218	152	97	477	384	302	231	170	119	76
1∅ 336.4 ACSR (18/1)	791	637	501	384	283	197	126	582	469	369	282	208	145	93	460	371	292	223	165	115	73
1∅ 477.0 ACSR (18/1)	744	599	471	361	266	186	119	556	448	353	270	199	139	89	444	357	281	215	159	111	71
3∅ 4 ACSR (7/1)	555	447	352	269	198	138	88	443	357	281	215	158	111	71	369	297	234	179	132	92	59
3∅ 1/O ACSR (6/1)	505	407	320	245	181	126	81	411	331	261	199	147	103	66	346	279	220	168	124	86	55
3∅ 4/O ACSR (6/1)	457	368	290	222	164	114	73	379	305	240	184	135	94	60	323	260	205	157	116	81	52
3∅ 336.4 ACSR (18/1)	428	344	271	208	153	107	68	358	288	227	174	128	89	57	308	248	195	150	110	77	49
3∅ 477.0 ACSR (18/1)	400	322	253	194	143	100	64	338	272	215	164	121	84	54	293	236	186	142	105	73	47

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	935	738	566	416	287	178	87	650	513	393	289	200	124	61	498	393	301	221	153	95	46
1∅ 1/O ACSR (6/1)	859	679	520	382	264	164	80	612	484	371	272	188	117	57	476	376	288	212	146	91	44
1∅ 4/O ACSR (6/1)	785	620	475	349	241	150	73	574	453	347	255	176	109	54	452	357	274	201	139	86	42
1∅ 336.4 ACSR (18/1)	739	583	447	329	227	141	69	549	433	332	244	168	104	51	436	344	264	194	134	83	41
1∅ 477.0 ACSR (18/1)	694	548	420	309	213	132	65	524	414	317	233	161	100	49	420	332	254	187	129	80	39
3∅ 4 ACSR (7/1)	517	408	313	230	159	98	48	416	329	252	185	128	79	39	348	275	211	155	107	66	33
3∅ 1/O ACSR (6/1)	471	372	285	209	145	90	44	386	304	233	171	118	73	36	326	258	198	145	100	62	30
3∅ 4/O ACSR (6/1)	426	336	258	189	131	81	40	355	280	215	158	109	68	33	304	240	184	135	93	58	28
3∅ 336.4 ACSR (18/1)	398	314	241	177	122	76	37	336	265	203	149	103	64	31	290	229	175	129	89	55	27
3∅ 477.0 ACSR (18/1)	372	294	225	166	114	71	35	317	250	192	141	97	60	30	276	218	167	123	85	53	26

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	556	449	354	273	202	143	93	439	354	280	215	160	113	74	363	293	231	178	132	93	61
3∅ 1/O ACSR (6/1)	507	409	323	248	184	130	85	408	329	260	200	149	105	68	341	275	218	167	124	88	57
3∅ 4/O ACSR (6/1)	459	370	293	225	167	118	77	376	304	240	185	137	97	63	319	257	203	156	116	82	54
3∅ 336.4 ACSR (18/1)	429	347	274	211	156	110	72	356	288	227	175	130	92	60	305	246	194	149	111	78	51
3∅ 477.0 ACSR (18/1)	402	324	256	197	146	103	67	337	272	215	165	123	87	57	290	234	185	142	106	75	49

NESC Extreme Wind (120 mph) - Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	474	366	271	188	117	57	7	379	292	216	150	94	46	6	315	243	180	125	78	38	5
3∅ 1/O ACSR (6/1)	432	333	247	171	107	52	7	351	271	201	139	87	43	6	296	228	169	118	73	36	5
3∅ 4/O ACSR (6/1)	391	301	223	155	97	47	6	324	250	185	129	80	39	5	276	213	158	110	68	33	4
3∅ 336.4 ACSR (18/1)	365	282	209	145	91	44	6	306	236	175	122	76	37	5	263	203	150	105	65	32	4
3∅ 477.0 ACSR (18/1)	342	264	195	136	85	41	5	289	223	165	115	72	35	5	251	193	143	100	62	30	4

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	355	246	151	68	-	-	-	286	198	121	55	-	-	-	239	166	101	46	-	-	-
3∅ 1/O ACSR (6/1)	323	224	137	62	-	-	-	265	183	112	51	-	-	-	224	155	95	43	-	-	-
3∅ 4/O ACSR (6/1)	292	203	124	56	-	-	-	244	169	103	47	-	-	-	209	145	89	40	-	-	-
3∅ 336.4 ACSR (18/1)	273	190	116	52	-	-	-	230	160	98	44	-	-	-	199	138	84	38	-	-	-
3∅ 477.0 ACSR (18/1)	255	177	108	49	-	-	-	217	151	92	42	-	-	-	189	131	80	36	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	537	428	332	248	176	115	65	438	348	270	202	143	94	53	369	294	228	170	121	79	45
3∅ 1/O ACSR (6/1)	489	389	302	226	160	105	59	405	322	250	187	133	87	49	345	275	213	159	113	74	42
3∅ 4/O ACSR (6/1)	442	352	273	204	145	95	53	372	296	230	172	122	80	45	321	256	198	148	105	69	39
3∅ 336.4 ACSR (18/1)	413	329	255	191	135	89	50	351	280	217	162	115	75	42	306	243	189	141	100	66	37
3∅ 477.0 ACSR (18/1)	386	307	238	178	127	83	47	332	264	205	153	109	71	40	291	231	179	134	95	62	35

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	517	408	313	230	158	98	48	418	330	253	185	128	79	38	350	276	212	155	107	66	32
3∅ 1/O ACSR (6/1)	471	372	285	209	144	89	43	387	305	234	172	118	73	36	328	259	198	146	100	62	30
3∅ 4/O ACSR (6/1)	426	336	258	189	130	81	39	356	281	215	158	109	67	33	306	241	185	136	94	58	28
3∅ 336.4 ACSR (18/1)	398	314	241	177	122	75	37	336	266	203	149	103	64	31	291	230	176	129	89	55	27
3∅ 477.0 ACSR (18/1)	372	294	225	165	114	70	34	318	251	192	141	97	60	29	277	219	167	123	85	52	26

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	479	370	274	190	119	58	7	390	301	223	155	96	47	6	328	253	187	130	81	40	5
3∅ 1/O ACSR (6/1)	436	337	249	173	108	53	7	361	278	206	143	89	44	6	307	237	176	122	76	37	5
3∅ 4/O ACSR (6/1)	394	304	225	157	98	48	6	332	256	189	132	82	40	5	286	221	163	114	71	35	4
3∅ 336.4 ACSR (18/1)	369	284	211	146	91	45	6	313	242	179	124	78	38	5	272	210	155	108	67	33	4
3∅ 477.0 ACSR (18/1)	344	266	197	137	85	42	5	296	228	169	117	73	36	5	259	200	148	103	64	31	4

NESC Extreme Wind (120 mph) - Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,617	1,331	1,080	861	673	512	378	1,080	889	721	575	449	342	253	810	667	541	432	337	257	190
1∅ 1/O ACSR (6/1)	1,491	1,228	996	794	621	473	349	1,022	842	683	544	425	324	239	777	640	519	414	324	246	182
1∅ 4/O ACSR (6/1)	1,367	1,125	913	728	569	433	320	962	792	643	513	400	305	225	742	611	496	395	309	235	174
1∅ 336.4 ACSR (18/1)	1,288	1,061	861	686	536	408	301	922	759	616	491	384	292	216	718	592	480	383	299	228	168
1∅ 477.0 ACSR (18/1)	1,213	999	810	646	505	385	284	883	727	590	471	368	280	207	694	572	464	370	289	220	162
3∅ 4 ACSR (7/1)	910	749	608	485	379	288	213	711	585	475	379	296	225	166	583	480	390	311	243	185	136
3∅ 1/O ACSR (6/1)	830	683	554	442	345	263	194	661	544	442	352	275	210	155	549	452	367	293	229	174	128
3∅ 4/O ACSR (6/1)	752	619	503	401	313	238	176	611	503	408	325	254	194	143	514	423	343	274	214	163	120
3∅ 336.4 ACSR (18/1)	704	580	470	375	293	223	165	579	476	387	308	241	183	135	491	404	328	262	204	156	115
3∅ 477.0 ACSR (18/1)	659	542	440	351	274	209	154	548	451	366	292	228	174	128	469	386	313	250	195	149	110

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,616	1,326	1,071	849	658	495	359	1,095	899	726	576	446	336	243	828	680	549	435	337	254	184
1∅ 1/O ACSR (6/1)	1,489	1,221	987	782	606	456	330	1,035	850	686	544	421	317	230	794	651	526	417	323	243	176
1∅ 4/O ACSR (6/1)	1,363	1,118	903	716	555	417	303	973	798	645	511	396	298	216	756	621	501	397	308	232	168
1∅ 336.4 ACSR (18/1)	1,283	1,053	851	674	522	393	285	932	765	618	490	379	285	207	731	600	485	384	298	224	162
1∅ 477.0 ACSR (18/1)	1,208	991	801	635	492	370	268	891	731	591	468	363	273	198	706	579	468	371	287	216	157
3∅ 4 ACSR (7/1)	903	741	599	475	368	277	201	714	586	473	375	291	219	158	590	484	391	310	240	181	131
3∅ 1/O ACSR (6/1)	823	676	546	433	335	252	183	663	544	439	348	270	203	147	555	455	368	291	226	170	123
3∅ 4/O ACSR (6/1)	746	612	494	392	304	228	166	612	502	405	321	249	187	136	518	425	344	272	211	159	115
3∅ 336.4 ACSR (18/1)	698	573	463	367	284	214	155	579	475	384	304	236	177	129	495	406	328	260	201	152	110
3∅ 477.0 ACSR (18/1)	653	536	433	343	266	200	145	548	449	363	288	223	168	122	472	387	313	248	192	144	105

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,571	1,277	1,018	793	599	434	296	1,081	879	701	546	412	299	204	824	670	534	416	314	228	155
1∅ 1/O ACSR (6/1)	1,446	1,175	937	730	551	399	272	1,020	829	661	515	389	282	192	788	641	511	398	301	218	148
1∅ 4/O ACSR (6/1)	1,322	1,075	857	668	504	365	249	957	778	621	483	365	264	180	750	610	486	379	286	207	141
1∅ 336.4 ACSR (18/1)	1,244	1,011	807	628	474	344	234	916	744	594	462	349	253	172	724	589	470	366	276	200	136
1∅ 477.0 ACSR (18/1)	1,170	951	758	591	446	323	220	875	711	567	442	334	242	165	699	568	453	353	266	193	132
3∅ 4 ACSR (7/1)	873	709	566	441	333	241	164	697	567	452	352	266	193	131	581	472	376	293	221	160	109
3∅ 1/O ACSR (6/1)	795	646	515	401	303	220	150	647	526	419	326	247	179	122	545	443	353	275	208	151	103
3∅ 4/O ACSR (6/1)	720	585	466	363	274	199	135	596	484	386	301	227	165	112	509	413	330	257	194	140	96
3∅ 336.4 ACSR (18/1)	673	547	436	340	257	186	127	564	458	365	285	215	156	106	485	394	314	245	185	134	91
3∅ 477.0 ACSR (18/1)	629	511	408	318	240	174	118	533	433	345	269	203	147	100	462	375	299	233	176	128	87

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,485	1,188	927	699	503	337	197	1,032	826	644	486	350	234	137	791	633	494	373	268	179	105
1∅ 1/O ACSR (6/1)	1,365	1,092	852	643	463	310	181	973	778	607	458	330	221	129	756	605	472	356	256	171	100
1∅ 4/O ACSR (6/1)	1,248	998	779	588	423	283	166	912	729	569	429	309	207	121	718	575	448	338	244	163	95
1∅ 336.4 ACSR (18/1)	1,173	939	732	553	398	266	156	871	697	544	410	296	198	116	693	554	433	326	235	157	92
1∅ 477.0 ACSR (18/1)	1,103	882	689	520	374	250	147	832	666	519	392	282	189	111	668	534	417	315	226	152	89
3∅ 4 ACSR (7/1)	821	657	513	387	279	186	109	661	529	413	311	224	150	88	553	442	345	260	188	125	73
3∅ 1/O ACSR (6/1)	748	598	467	352	254	170	99	612	490	382	288	208	139	81	519	415	324	244	176	118	69
3∅ 4/O ACSR (6/1)	677	541	422	319	229	154	90	564	451	352	266	191	128	75	483	387	302	228	164	110	64
3∅ 336.4 ACSR (18/1)	633	506	395	298	215	144	84	533	426	333	251	181	121	71	460	368	287	217	156	104	61
3∅ 477.0 ACSR (18/1)	591	473	369	278	200	134	79	503	403	314	237	171	114	67	438	351	273	206	149	99	58

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	875	713	571	447	340	249	172	691	563	451	353	268	196	136	572	466	373	292	222	162	113
3∅ 1/O ACSR (6/1)	798	650	520	407	309	227	157	642	523	419	328	249	182	126	537	438	350	274	208	153	106
3∅ 4/O ACSR (6/1)	723	589	471	369	280	205	142	593	483	386	302	230	168	117	502	409	327	256	195	143	99
3∅ 336.4 ACSR (18/1)	676	551	441	345	262	192	133	561	457	366	286	218	159	110	479	391	313	245	186	136	94
3∅ 477.0 ACSR (18/1)	632	515	412	323	245	180	125	530	432	346	271	206	151	104	457	372	298	233	177	130	90

NESC Extreme Wind (120 mph) - Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	769	605	462	337	229	137	60	614	484	369	269	183	109	48	511	403	307	224	152	91	40
3∅ 1/O ACSR (6/1)	700	551	420	306	208	125	55	570	448	342	249	169	101	45	480	378	288	210	143	86	38
3∅ 4/O ACSR (6/1)	634	499	381	277	189	113	50	525	413	315	230	156	94	41	448	353	269	196	133	80	35
3∅ 336.4 ACSR (18/1)	593	467	356	259	176	106	46	496	391	298	217	148	88	39	427	336	256	187	127	76	33
3∅ 477.0 ACSR (18/1)	554	436	333	243	165	99	43	469	369	282	205	140	84	37	407	320	244	178	121	72	32

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	605	440	296	170	62	-	-	487	354	238	137	50	-	-	407	297	199	115	42	-	-
3∅ 1/O ACSR (6/1)	550	401	270	155	56	-	-	451	328	221	127	46	-	-	382	278	187	108	39	-	-
3∅ 4/O ACSR (6/1)	498	363	244	140	51	-	-	415	302	203	117	43	-	-	356	259	174	100	36	-	-
3∅ 336.4 ACSR (18/1)	466	339	228	131	48	-	-	392	286	192	111	40	-	-	339	247	166	95	35	-	-
3∅ 477.0 ACSR (18/1)	435	317	213	123	45	-	-	371	270	181	104	38	-	-	323	235	158	91	33	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	850	685	539	412	303	210	132	692	558	439	336	247	171	108	584	470	370	283	208	144	91
3∅ 1/O ACSR (6/1)	773	623	490	375	276	191	120	640	516	406	311	228	158	100	547	440	347	265	195	135	85
3∅ 4/O ACSR (6/1)	699	563	444	339	249	173	109	589	474	373	286	210	146	92	509	410	322	247	181	126	79
3∅ 336.4 ACSR (18/1)	654	526	414	317	233	162	102	556	448	353	270	198	137	87	484	390	307	235	172	120	75
3∅ 477.0 ACSR (18/1)	611	492	387	296	218	151	95	525	422	333	254	187	130	82	460	370	292	223	164	114	72

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	823	658	513	387	279	186	109	664	531	414	313	225	150	88	557	445	347	262	189	126	74
3∅ 1/O ACSR (6/1)	749	599	467	352	254	169	99	615	492	384	289	208	139	81	522	417	326	246	177	118	69
3∅ 4/O ACSR (6/1)	677	542	423	319	229	153	90	566	453	353	266	192	128	75	486	389	303	229	165	110	64
3∅ 336.4 ACSR (18/1)	633	506	395	298	214	143	84	535	428	334	252	181	121	71	463	370	289	218	157	105	61
3∅ 477.0 ACSR (18/1)	592	473	369	278	200	134	78	505	404	315	238	171	114	67	440	352	275	207	149	100	58

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	770	604	459	332	223	130	52	626	491	373	270	181	106	43	527	414	314	227	153	89	36
3∅ 1/O ACSR (6/1)	700	550	417	302	203	118	48	579	454	345	250	168	98	39	493	387	294	213	143	83	34
3∅ 4/O ACSR (6/1)	633	497	378	273	183	107	43	532	418	317	230	154	90	36	459	361	274	198	133	78	31
3∅ 336.4 ACSR (18/1)	592	465	353	255	171	100	40	503	395	300	217	146	85	34	437	343	261	189	127	74	30
3∅ 477.0 ACSR (18/1)	553	434	330	239	160	94	38	474	372	283	205	137	80	32	415	326	248	179	120	70	28

NESC Extreme Wind (150 mph) - Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	941	759	599	461	344	245	164	629	506	400	308	229	164	110	472	380	300	231	172	123	82
1∅ 1/O ACSR (6/1)	855	688	541	415	307	217	144	586	471	371	284	211	149	98	446	359	282	216	160	113	75
1∅ 4/O ACSR (6/1)	784	630	496	380	282	199	132	552	444	349	268	198	140	93	426	342	269	207	153	108	71
1∅ 336.4 ACSR (18/1)	739	594	468	358	266	188	124	529	425	335	257	190	135	89	412	331	261	200	148	105	69
1∅ 477.0 ACSR (18/1)	696	559	440	338	250	177	117	507	407	321	246	182	129	85	398	320	252	193	143	101	67
3∅ 4 ACSR (7/1)	522	420	330	253	188	133	88	408	328	258	198	147	104	68	335	269	212	162	120	85	56
3∅ 1/O ACSR (6/1)	476	383	301	231	171	121	80	379	305	240	184	136	96	64	315	253	199	153	113	80	53
3∅ 4/O ACSR (6/1)	432	347	273	209	155	110	72	350	282	222	170	126	89	59	295	237	187	143	106	75	50
3∅ 336.4 ACSR (18/1)	404	325	256	196	145	103	68	332	267	210	161	119	84	56	282	227	178	137	101	72	47
3∅ 477.0 ACSR (18/1)	378	304	239	183	136	96	63	314	253	199	152	113	80	53	269	216	170	130	97	68	45

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	921	736	575	436	318	219	137	624	499	390	296	215	148	93	472	377	295	224	163	112	70
1∅ 1/O ACSR (6/1)	848	678	530	402	293	201	127	590	472	368	279	204	140	88	452	362	282	214	156	107	68
1∅ 4/O ACSR (6/1)	777	621	485	368	268	184	116	554	443	346	263	191	132	83	431	345	269	204	149	102	64
1∅ 336.4 ACSR (18/1)	731	585	457	346	252	174	109	531	425	332	251	183	126	79	417	333	260	197	144	99	62
1∅ 477.0 ACSR (18/1)	688	550	430	326	238	163	103	508	406	317	241	175	121	76	402	322	251	191	139	96	60
3∅ 4 ACSR (7/1)	515	412	322	244	178	122	77	407	325	254	193	140	97	61	336	269	210	159	116	80	50
3∅ 1/O ACSR (6/1)	469	375	293	222	162	111	70	378	302	236	179	130	90	56	316	253	197	150	109	75	47
3∅ 4/O ACSR (6/1)	425	340	265	201	147	101	63	349	279	218	165	120	83	52	295	236	185	140	102	70	44
3∅ 336.4 ACSR (18/1)	398	318	248	188	137	94	59	330	264	206	156	114	78	49	282	225	176	134	97	67	42
3∅ 477.0 ACSR (18/1)	372	297	232	176	128	88	56	312	249	195	148	108	74	47	269	215	168	127	93	64	40

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	882	695	531	390	270	170	87	607	478	366	269	186	117	60	463	365	279	205	142	89	46
1∅ 1/O ACSR (6/1)	812	639	489	359	249	156	80	573	451	345	254	176	110	57	443	349	267	196	136	85	44
1∅ 4/O ACSR (6/1)	742	585	447	329	228	143	74	537	423	324	238	165	103	53	421	332	254	186	129	81	42
1∅ 336.4 ACSR (18/1)	699	550	421	309	214	135	69	514	405	310	228	158	99	51	407	320	245	180	125	78	40
1∅ 477.0 ACSR (18/1)	657	517	396	291	201	127	65	491	387	296	217	151	95	49	392	309	236	174	120	76	39
3∅ 4 ACSR (7/1)	490	386	295	217	150	94	49	392	308	236	173	120	75	39	326	257	196	144	100	63	32
3∅ 1/O ACSR (6/1)	446	352	269	198	137	86	44	363	286	219	161	111	70	36	306	241	184	135	94	59	30
3∅ 4/O ACSR (6/1)	404	318	243	179	124	78	40	335	264	202	148	103	64	33	286	225	172	126	88	55	28
3∅ 336.4 ACSR (18/1)	378	298	228	167	116	73	37	316	249	191	140	97	61	31	272	214	164	120	83	52	27
3∅ 477.0 ACSR (18/1)	353	278	213	156	108	68	35	299	236	180	132	92	58	30	259	204	156	115	79	50	26

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	817	628	463	321	200	98	15	568	437	322	223	139	68	10	435	335	247	171	106	52	8
1∅ 1/O ACSR (6/1)	751	577	426	295	183	90	14	535	411	303	210	131	64	10	416	320	236	163	102	50	8
1∅ 4/O ACSR (6/1)	687	528	389	269	168	82	12	502	386	284	197	123	60	9	395	304	224	155	97	47	7
1∅ 336.4 ACSR (18/1)	646	496	366	253	158	78	12	480	369	272	188	117	58	9	381	293	216	150	93	46	7
1∅ 477.0 ACSR (18/1)	607	467	344	238	148	73	11	458	352	259	180	112	55	8	368	282	208	144	90	44	7
3∅ 4 ACSR (7/1)	452	347	256	177	110	54	8	364	280	206	143	89	44	7	304	234	172	119	74	37	6
3∅ 1/O ACSR (6/1)	411	316	233	161	100	49	7	337	259	191	132	82	40	6	285	219	162	112	70	34	5
3∅ 4/O ACSR (6/1)	372	286	211	146	91	45	7	310	239	176	122	76	37	6	266	204	151	104	65	32	5
3∅ 336.4 ACSR (18/1)	348	268	197	137	85	42	6	293	225	166	115	72	35	5	253	195	144	99	62	30	5
3∅ 477.0 ACSR (18/1)	325	250	184	128	79	39	6	277	213	157	109	68	33	5	241	185	137	95	59	29	4

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	492	389	298	221	155	99	54	389	307	236	174	122	78	43	321	254	195	144	101	65	35
3∅ 1/O ACSR (6/1)	448	354	272	201	141	90	49	361	285	219	162	113	73	39	302	239	183	136	95	61	33
3∅ 4/O ACSR (6/1)	406	321	246	182	128	82	44	333	263	202	150	105	67	36	282	223	171	127	89	57	31
3∅ 336.4 ACSR (18/1)	380	300	231	171	119	77	42	315	249	191	142	99	64	34	269	213	163	121	85	54	29
3∅ 477.0 ACSR (18/1)	355	281	216	160	112	72	39	298	235	181	134	94	60	33	257	203	156	115	81	52	28

NESC Extreme Wind (150 mph) - Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	409	305	214	136	69	13	-	327	244	171	109	55	11	-	272	203	143	90	46	9	-
3∅ 1/O ACSR (6/1)	373	278	195	124	63	12	-	303	226	159	101	51	10	-	255	190	134	85	43	8	-
3∅ 4/O ACSR (6/1)	337	252	177	112	57	11	-	279	208	146	93	47	9	-	238	178	125	79	40	8	-
3∅ 336.4 ACSR (18/1)	315	235	165	105	53	10	-	264	197	138	88	45	9	-	227	169	119	75	38	7	-
3∅ 477.0 ACSR (18/1)	295	220	154	98	50	10	-	250	186	131	83	42	8	-	216	161	113	72	37	7	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	290	185	94	15	-	-	-	233	149	76	12	-	-	-	195	125	63	10	-	-	-
3∅ 1/O ACSR (6/1)	264	169	86	14	-	-	-	216	138	70	11	-	-	-	183	117	59	10	-	-	-
3∅ 4/O ACSR (6/1)	239	153	77	13	-	-	-	199	127	64	10	-	-	-	171	109	55	9	-	-	-
3∅ 336.4 ACSR (18/1)	223	143	72	12	-	-	-	188	120	61	10	-	-	-	162	104	53	9	-	-	-
3∅ 477.0 ACSR (18/1)	209	133	68	11	-	-	-	178	113	58	9	-	-	-	155	99	50	8	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	472	366	274	195	127	71	24	384	298	223	159	104	58	20	324	252	188	134	87	49	17
3∅ 1/O ACSR (6/1)	429	333	250	177	116	64	22	355	276	207	147	96	53	18	303	235	176	125	82	46	16
3∅ 4/O ACSR (6/1)	388	301	226	160	105	58	20	327	254	190	135	88	49	17	282	219	164	117	76	42	15
3∅ 336.4 ACSR (18/1)	363	282	211	150	98	54	19	309	240	179	128	83	46	16	268	208	156	111	73	40	14
3∅ 477.0 ACSR (18/1)	339	263	197	140	92	51	18	291	226	169	120	79	44	15	255	198	148	105	69	38	13

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	452	347	256	177	110	54	7	365	280	207	143	89	43	6	306	235	173	120	74	36	5
3∅ 1/O ACSR (6/1)	412	316	233	161	100	49	7	338	260	191	132	82	40	6	287	220	162	112	70	34	5
3∅ 4/O ACSR (6/1)	372	286	211	146	90	44	6	311	239	176	122	76	37	5	267	205	151	105	65	32	4
3∅ 336.4 ACSR (18/1)	348	267	197	136	85	41	6	294	226	166	115	71	35	5	255	196	144	100	62	30	4
3∅ 477.0 ACSR (18/1)	325	250	184	127	79	39	5	278	213	157	109	67	33	5	242	186	137	95	59	29	4

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	414	309	217	137	70	13	-	336	251	176	112	57	11	-	283	211	148	94	48	9	-
3∅ 1/O ACSR (6/1)	377	281	197	125	64	12	-	311	232	163	103	53	10	-	265	198	139	88	45	9	-
3∅ 4/O ACSR (6/1)	341	254	178	113	58	11	-	286	213	150	95	48	9	-	247	184	129	82	42	8	-
3∅ 336.4 ACSR (18/1)	318	237	167	106	54	10	-	270	202	142	90	46	9	-	235	175	123	78	40	8	-
3∅ 477.0 ACSR (18/1)	297	222	156	99	50	10	-	255	190	134	85	43	8	-	223	167	117	74	38	7	-

NESC Extreme Wind (150 mph) - Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,488	1,211	968	757	577	425	299	994	808	646	506	385	284	200	746	607	485	380	289	213	150
1∅ 1/O ACSR (6/1)	1,373	1,117	893	699	532	392	276	941	765	612	479	365	269	189	716	582	465	364	278	204	144
1∅ 4/O ACSR (6/1)	1,258	1,024	818	640	488	359	253	886	721	576	451	343	253	178	683	556	444	348	265	195	137
1∅ 336.4 ACSR (18/1)	1,186	965	771	603	460	339	238	849	691	552	432	329	243	171	661	538	430	337	256	189	133
1∅ 477.0 ACSR (18/1)	1,117	908	726	568	433	319	224	813	661	529	414	315	232	163	639	520	416	325	248	183	128
3∅ 4 ACSR (7/1)	837	681	545	426	325	239	168	654	532	426	333	254	187	131	537	437	349	273	208	153	108
3∅ 1/O ACSR (6/1)	764	621	497	389	296	218	153	608	495	396	310	236	174	122	506	411	329	257	196	144	102
3∅ 4/O ACSR (6/1)	692	563	450	352	269	198	139	562	457	366	286	218	161	113	473	385	308	241	184	135	95
3∅ 336.4 ACSR (18/1)	648	527	422	330	251	185	130	533	433	346	271	207	152	107	452	368	294	230	175	129	91
3∅ 477.0 ACSR (18/1)	606	493	394	309	235	173	122	504	410	328	257	196	144	101	431	351	281	220	167	123	87

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,485	1,204	957	744	561	406	278	1,007	816	649	504	380	275	189	762	617	491	381	287	208	143
1∅ 1/O ACSR (6/1)	1,368	1,109	882	685	516	374	256	952	771	613	476	359	260	178	730	591	470	365	275	200	137
1∅ 4/O ACSR (6/1)	1,253	1,015	807	627	473	343	235	894	725	576	448	338	245	168	695	564	448	348	262	190	130
1∅ 336.4 ACSR (18/1)	1,180	956	760	591	445	323	221	856	694	552	429	323	234	160	672	545	433	337	254	184	126
1∅ 477.0 ACSR (18/1)	1,110	900	716	556	419	304	208	819	664	528	410	309	224	154	649	526	418	325	245	178	122
3∅ 4 ACSR (7/1)	830	673	535	416	313	227	156	656	532	423	328	248	179	123	542	439	349	271	205	148	102
3∅ 1/O ACSR (6/1)	757	613	488	379	286	207	142	609	494	393	305	230	167	114	510	413	329	255	192	139	96
3∅ 4/O ACSR (6/1)	686	556	442	343	259	188	128	562	456	362	282	212	154	105	477	386	307	239	180	130	89
3∅ 336.4 ACSR (18/1)	641	520	413	321	242	175	120	532	431	343	266	201	146	100	455	369	293	228	172	124	85
3∅ 477.0 ACSR (18/1)	600	486	387	300	226	164	112	503	408	324	252	190	138	94	433	351	279	217	164	119	81

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,439	1,153	903	686	501	344	214	990	794	621	472	345	237	147	755	605	474	360	263	180	112
1∅ 1/O ACSR (6/1)	1,324	1,061	831	631	461	317	197	934	749	586	446	325	223	139	722	579	453	344	251	173	107
1∅ 4/O ACSR (6/1)	1,211	970	760	577	421	289	180	877	703	550	418	305	210	131	687	551	431	328	239	164	102
1∅ 336.4 ACSR (18/1)	1,139	913	715	543	396	272	170	839	672	526	400	292	200	125	663	532	416	316	231	159	99
1∅ 477.0 ACSR (18/1)	1,071	859	673	511	373	256	160	801	642	503	382	279	192	119	640	513	402	305	223	153	95
3∅ 4 ACSR (7/1)	799	641	502	381	278	191	119	639	512	401	305	222	153	95	532	426	334	254	185	127	79
3∅ 1/O ACSR (6/1)	728	583	457	347	253	174	108	592	475	372	282	206	142	88	499	400	313	238	174	119	74
3∅ 4/O ACSR (6/1)	659	528	414	314	229	158	98	546	437	343	260	190	130	81	466	373	292	222	162	111	69
3∅ 336.4 ACSR (18/1)	616	494	387	294	214	147	92	516	414	324	246	180	123	77	444	356	279	212	154	106	66
3∅ 477.0 ACSR (18/1)	576	462	362	275	200	138	86	488	391	306	233	170	117	73	423	339	265	202	147	101	63

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1,351	1,063	810	591	404	246	115	939	739	563	411	281	171	80	720	566	432	315	215	131	61
1∅ 1/O ACSR (6/1)	1,242	977	745	544	372	226	106	885	696	531	388	265	161	75	688	541	412	301	206	125	59
1∅ 4/O ACSR (6/1)	1,135	893	681	497	340	207	97	829	652	497	363	248	151	71	653	514	392	286	195	119	56
1∅ 336.4 ACSR (18/1)	1,068	840	640	467	319	194	91	793	624	476	347	237	144	67	631	496	378	276	189	115	54
1∅ 477.0 ACSR (18/1)	1,004	790	602	439	300	183	85	757	595	454	331	226	138	64	608	478	364	266	182	111	52
3∅ 4 ACSR (7/1)	747	588	448	327	224	136	64	601	473	361	263	180	110	51	503	396	302	220	151	92	43
3∅ 1/O ACSR (6/1)	680	535	408	298	203	124	58	557	438	334	244	167	101	47	472	371	283	207	141	86	40
3∅ 4/O ACSR (6/1)	616	484	369	270	184	112	52	513	404	308	225	153	93	44	440	346	264	193	132	80	37
3∅ 336.4 ACSR (18/1)	576	453	345	252	172	105	49	485	381	291	212	145	88	41	419	330	251	183	125	76	36
3∅ 477.0 ACSR (18/1)	538	423	323	235	161	98	46	458	360	275	200	137	83	39	399	314	239	175	119	73	34

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	802	645	507	388	285	199	127	634	509	401	306	225	157	101	524	421	331	253	186	130	83
3∅ 1/O ACSR (6/1)	731	588	462	353	260	181	116	589	473	372	284	209	146	94	493	396	311	238	175	122	78
3∅ 4/O ACSR (6/1)	662	532	419	320	236	164	105	543	437	343	262	193	135	86	460	370	291	222	164	114	73
3∅ 336.4 ACSR (18/1)	620	498	392	299	220	154	98	514	413	325	248	183	128	82	439	353	278	212	156	109	70
3∅ 477.0 ACSR (18/1)	580	466	366	280	206	144	92	486	391	307	235	173	121	77	419	337	265	202	149	104	67

NESC Extreme Wind (150 mph) - Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	695	536	398	277	174	87	15	555	429	318	221	139	69	12	462	357	264	184	116	58	10
3∅ 1/O ACSR (6/1)	633	489	362	252	158	79	14	515	397	295	205	129	64	11	434	335	248	173	109	54	9
3∅ 4/O ACSR (6/1)	573	442	328	228	143	72	12	475	366	271	189	119	59	10	405	313	232	161	101	51	9
3∅ 336.4 ACSR (18/1)	536	414	307	214	134	67	11	449	346	257	179	112	56	10	386	298	221	154	97	48	8
3∅ 477.0 ACSR (18/1)	501	387	287	200	125	63	11	424	327	243	169	106	53	9	368	284	210	147	92	46	8

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	531	371	232	111	7	-	-	427	299	186	89	6	-	-	357	250	156	74	5	-	-
3∅ 1/O ACSR (6/1)	483	338	211	101	6	-	-	396	277	173	82	5	-	-	335	234	146	70	4	-	-
3∅ 4/O ACSR (6/1)	437	306	191	91	6	-	-	364	255	159	76	5	-	-	312	218	136	65	4	-	-
3∅ 336.4 ACSR (18/1)	409	286	178	85	5	-	-	344	241	150	72	4	-	-	298	208	130	62	4	-	-
3∅ 477.0 ACSR (18/1)	382	267	167	80	5	-	-	325	227	142	68	4	-	-	283	198	124	59	4	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	776	615	474	352	248	160	86	632	501	386	287	202	130	70	533	422	326	242	170	110	59
3∅ 1/O ACSR (6/1)	706	559	431	320	225	145	79	584	463	357	265	187	120	65	499	395	305	226	159	103	56
3∅ 4/O ACSR (6/1)	638	506	390	290	204	131	71	537	426	328	244	172	110	60	464	368	284	211	148	95	52
3∅ 336.4 ACSR (18/1)	596	473	365	271	190	123	66	507	402	310	230	162	104	57	441	350	270	200	141	91	49
3∅ 477.0 ACSR (18/1)	557	442	341	253	178	115	62	479	379	293	217	153	98	53	420	333	256	190	134	86	47

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	748	589	449	327	223	136	63	604	475	362	264	180	110	51	507	398	304	222	151	92	43
3∅ 1/O ACSR (6/1)	681	536	408	298	203	124	57	560	440	335	245	167	102	47	475	373	285	208	142	86	40
3∅ 4/O ACSR (6/1)	616	485	369	270	184	112	52	515	405	309	225	154	93	43	442	348	265	193	132	80	37
3∅ 336.4 ACSR (18/1)	576	453	345	252	172	105	49	487	383	292	213	145	88	41	421	331	253	184	126	76	36
3∅ 477.0 ACSR (18/1)	538	423	323	235	161	98	45	459	361	275	201	137	83	39	401	315	240	175	120	73	34

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	695	535	394	272	168	80	7	565	434	320	221	136	65	5	476	366	270	186	115	54	5
3∅ 1/O ACSR (6/1)	632	486	358	247	152	72	6	523	402	296	205	126	60	5	446	343	253	174	107	51	4
3∅ 4/O ACSR (6/1)	572	440	324	224	138	65	5	481	370	272	188	116	55	5	415	319	235	162	100	47	4
3∅ 336.4 ACSR (18/1)	534	411	303	209	129	61	5	454	349	257	178	109	52	4	395	304	224	154	95	45	4
3∅ 477.0 ACSR (18/1)	499	384	283	195	120	57	5	428	329	243	168	103	49	4	375	289	213	147	90	43	4

APPENDIX H. GO 95 NESC ALLOWABLE WIND SPANS

GO 95 - Light Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,311	3,537	2,856	2,265	1,756	1,324	964	1,017	834	674	534	414	312	227	576	473	382	303	235	177	129
1∅ 1/O ACSR (6/1)	2,784	2,284	1,845	1,462	1,134	855	623	900	739	596	473	367	277	201	537	440	356	282	219	165	120
1∅ 4/O ACSR (6/1)	1,968	1,614	1,304	1,034	802	605	440	794	651	526	417	323	244	178	497	408	329	261	203	153	111
1∅ 336.4 ACSR (18/1)	1,620	1,329	1,073	851	660	498	362	731	599	484	384	298	224	163	472	387	312	248	192	145	105
1∅ 477.0 ACSR (18/1)	1,361	1,117	902	715	554	418	304	673	552	446	353	274	207	150	447	367	296	235	182	137	100
3∅ 4 ACSR (7/1)	2,119	1,738	1,404	1,113	863	651	474	817	670	542	429	333	251	183	506	415	335	266	206	156	113
3∅ 1/O ACSR (6/1)	1,368	1,123	907	719	557	420	306	675	553	447	354	275	207	151	448	367	297	235	182	138	100
3∅ 4/O ACSR (6/1)	967	794	641	508	394	297	216	560	459	371	294	228	172	125	394	323	261	207	161	121	88
3∅ 336.4 ACSR (18/1)	796	653	528	418	324	245	178	498	409	330	262	203	153	111	362	297	240	190	148	111	81
3∅ 477.0 ACSR (18/1)	669	549	443	351	273	206	150	445	365	295	234	181	137	100	334	274	221	175	136	102	75

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	4,191	3,416	2,736	2,144	1,635	1,204	843	1,035	844	676	530	404	297	208	590	481	385	302	230	170	119
1∅ 1/O ACSR (6/1)	2,706	2,206	1,766	1,384	1,056	777	545	912	743	595	466	356	262	183	548	447	358	280	214	157	110
1∅ 4/O ACSR (6/1)	1,913	1,559	1,249	979	746	549	385	800	652	522	409	312	230	161	506	412	330	259	197	145	102
1∅ 336.4 ACSR (18/1)	1,575	1,283	1,028	806	614	452	317	734	598	479	375	286	211	148	478	390	312	245	187	137	96
1∅ 477.0 ACSR (18/1)	1,323	1,078	864	677	516	380	266	674	550	440	345	263	194	136	452	369	295	231	177	130	91
3∅ 4 ACSR (7/1)	2,060	1,679	1,345	1,054	804	592	415	824	672	538	422	322	237	166	515	420	336	264	201	148	104
3∅ 1/O ACSR (6/1)	1,330	1,084	868	680	519	382	268	676	551	441	346	264	194	136	453	369	296	232	177	130	91
3∅ 4/O ACSR (6/1)	940	766	614	481	367	270	189	558	455	364	286	218	160	112	397	324	259	203	155	114	80
3∅ 336.4 ACSR (18/1)	774	631	505	396	302	222	156	495	404	323	253	193	142	100	364	297	238	186	142	105	73
3∅ 477.0 ACSR (18/1)	650	530	425	333	254	187	131	441	360	288	226	172	127	89	334	272	218	171	130	96	67

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,900	3,126	2,445	1,854	1,345	913	553	1,009	809	633	480	348	236	143	580	464	363	275	200	136	82
1∅ 1/O ACSR (6/1)	2,519	2,018	1,579	1,197	869	590	357	884	708	554	420	305	207	125	536	429	336	255	185	126	76
1∅ 4/O ACSR (6/1)	1,781	1,427	1,116	846	614	417	253	772	618	484	367	266	181	109	492	395	309	234	170	115	70
1∅ 336.4 ACSR (18/1)	1,466	1,174	919	697	505	343	208	706	566	443	335	243	165	100	465	373	291	221	160	109	66
1∅ 477.0 ACSR (18/1)	1,231	987	772	585	425	288	175	647	518	405	307	223	151	92	438	351	275	208	151	103	62
3∅ 4 ACSR (7/1)	1,917	1,536	1,202	911	661	449	272	796	638	499	378	275	186	113	502	403	315	239	173	118	71
3∅ 1/O ACSR (6/1)	1,238	992	776	588	427	290	176	648	520	407	308	224	152	92	439	352	275	209	151	103	62
3∅ 4/O ACSR (6/1)	875	701	549	416	302	205	124	533	427	334	253	184	125	76	383	307	240	182	132	90	54
3∅ 336.4 ACSR (18/1)	720	577	452	342	248	169	102	471	378	295	224	162	110	67	350	280	219	166	121	82	50
3∅ 477.0 ACSR (18/1)	605	485	380	288	209	142	86	419	336	263	199	144	98	59	320	257	201	152	110	75	45

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	3,507	2,733	2,052	1,461	952	520	160	936	729	548	390	254	139	43	540	421	316	225	147	80	25
1∅ 1/O ACSR (6/1)	2,265	1,765	1,325	943	615	336	103	816	636	478	340	222	121	37	498	388	291	207	135	74	23
1∅ 4/O ACSR (6/1)	1,601	1,247	937	667	435	238	73	710	553	416	296	193	105	32	456	356	267	190	124	68	21
1∅ 336.4 ACSR (18/1)	1,318	1,027	771	549	358	196	60	648	505	379	270	176	96	30	430	335	252	179	117	64	20
1∅ 477.0 ACSR (18/1)	1,107	863	648	461	301	164	51	593	462	347	247	161	88	27	405	315	237	169	110	60	18
3∅ 4 ACSR (7/1)	1,724	1,343	1,009	718	468	256	79	733	571	429	305	199	109	33	466	363	273	194	126	69	21
3∅ 1/O ACSR (6/1)	1,113	867	651	464	302	165	51	595	463	348	248	161	88	27	406	316	237	169	110	60	19
3∅ 4/O ACSR (6/1)	787	613	461	328	214	117	36	487	379	285	203	132	72	22	352	275	206	147	96	52	16
3∅ 336.4 ACSR (18/1)	648	505	379	270	176	96	30	430	335	251	179	117	64	20	321	250	188	134	87	48	15
3∅ 477.0 ACSR (18/1)	544	424	319	227	148	81	25	382	297	223	159	104	57	17	294	229	172	122	80	44	13

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,941	1,560	1,226	935	685	473	296	777	624	491	374	274	189	118	486	390	307	234	171	118	74
3∅ 1/O ACSR (6/1)	1,253	1,007	792	604	442	305	191	637	512	402	307	225	155	97	427	343	270	206	151	104	65
3∅ 4/O ACSR (6/1)	886	712	560	427	313	216	135	526	423	332	253	186	128	80	374	301	236	180	132	91	57
3∅ 336.4 ACSR (18/1)	729	586	461	351	257	178	111	467	375	295	225	165	114	71	343	276	217	165	121	84	52
3∅ 477.0 ACSR (18/1)	613	493	387	295	216	149	93	416	334	263	200	147	101	63	315	253	199	152	111	77	48

GO 95 - Light Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,513	1,132	798	507	257	45	-	628	470	331	211	107	19	-	397	297	209	133	67	12	-
3∅ 1/O ACSR (6/1)	977	731	515	328	166	29	-	512	383	270	172	87	15	-	347	259	183	116	59	10	-
3∅ 4/O ACSR (6/1)	691	517	364	232	117	21	-	420	315	222	141	71	12	-	302	226	159	101	51	9	-
3∅ 336.4 ACSR (18/1)	569	425	300	191	97	17	-	372	278	196	125	63	11	-	276	207	146	93	47	8	-
3∅ 477.0 ACSR (18/1)	478	358	252	160	81	14	-	331	247	174	111	56	10	-	253	189	133	85	43	8	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	936	555	220	-	-	-	-	398	236	94	-	-	-	-	253	150	60	-	-	-	-
3∅ 1/O ACSR (6/1)	604	358	142	-	-	-	-	323	191	76	-	-	-	-	220	131	52	-	-	-	-
3∅ 4/O ACSR (6/1)	427	253	101	-	-	-	-	264	157	62	-	-	-	-	191	113	45	-	-	-	-
3∅ 336.4 ACSR (18/1)	352	208	83	-	-	-	-	233	138	55	-	-	-	-	174	103	41	-	-	-	-
3∅ 477.0 ACSR (18/1)	295	175	70	-	-	-	-	207	123	49	-	-	-	-	159	95	38	-	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,800	1,419	1,085	794	544	332	155	796	628	480	351	241	147	68	511	403	308	225	154	94	44
3∅ 1/O ACSR (6/1)	1,162	916	700	513	351	214	100	641	505	386	283	194	118	55	442	349	267	195	134	81	38
3∅ 4/O ACSR (6/1)	822	648	495	362	248	151	71	522	411	314	230	158	96	45	382	301	230	169	115	70	33
3∅ 336.4 ACSR (18/1)	676	533	408	298	204	125	58	459	362	277	202	139	85	39	347	274	209	153	105	64	30
3∅ 477.0 ACSR (18/1)	568	448	342	251	172	105	49	406	320	245	179	123	75	35	316	249	191	140	96	58	27

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,719	1,338	1,004	713	463	251	74	739	575	432	307	199	108	32	471	366	275	195	127	69	20
3∅ 1/O ACSR (6/1)	1,110	864	648	461	299	162	48	598	466	349	248	161	87	26	409	319	239	170	110	60	18
3∅ 4/O ACSR (6/1)	785	611	458	326	211	115	34	489	381	286	203	132	71	21	355	276	207	147	96	52	15
3∅ 336.4 ACSR (18/1)	646	503	377	268	174	94	28	431	336	252	179	116	63	19	324	252	189	134	87	47	14
3∅ 477.0 ACSR (18/1)	543	423	317	225	146	79	23	383	298	223	159	103	56	16	295	230	173	123	80	43	13

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,530	1,149	815	524	274	62	-	673	506	358	231	120	27	-	432	324	230	148	77	17	-
3∅ 1/O ACSR (6/1)	988	742	526	338	177	40	-	542	407	289	186	97	22	-	374	281	199	128	67	15	-
3∅ 4/O ACSR (6/1)	698	525	372	239	125	28	-	442	332	235	151	79	18	-	323	243	172	111	58	13	-
3∅ 336.4 ACSR (18/1)	575	432	306	197	103	23	-	389	292	207	133	70	16	-	294	221	156	101	53	12	-
3∅ 477.0 ACSR (18/1)	483	363	257	165	86	19	-	345	259	183	118	62	14	-	268	201	143	92	48	11	-

GO 95 - Light Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	6,052	5,013	4,096	3,296	2,604	2,013	1,516	1,427	1,182	966	777	614	475	357	809	670	548	441	348	269	203
1∅ 1/O ACSR (6/1)	3,908	3,237	2,645	2,128	1,682	1,300	979	1,264	1,047	855	688	544	420	317	754	624	510	411	324	251	189
1∅ 4/O ACSR (6/1)	2,763	2,288	1,870	1,505	1,189	919	692	1,114	923	754	607	480	371	279	698	578	472	380	300	232	175
1∅ 336.4 ACSR (18/1)	2,274	1,883	1,539	1,238	979	756	570	1,025	849	694	558	441	341	257	662	548	448	361	285	220	166
1∅ 477.0 ACSR (18/1)	1,911	1,583	1,293	1,041	822	636	479	944	782	639	514	406	314	237	627	520	425	342	270	209	157
3∅ 4 ACSR (7/1)	2,975	2,464	2,013	1,620	1,280	990	745	1,147	950	777	625	494	382	287	711	589	481	387	306	236	178
3∅ 1/O ACSR (6/1)	1,921	1,591	1,300	1,046	827	639	481	947	784	641	516	407	315	237	628	520	425	342	270	209	157
3∅ 4/O ACSR (6/1)	1,358	1,125	919	740	584	452	340	786	651	532	428	338	262	197	553	458	375	301	238	184	139
3∅ 336.4 ACSR (18/1)	1,118	926	757	609	481	372	280	699	579	473	381	301	233	175	509	421	344	277	219	169	127
3∅ 477.0 ACSR (18/1)	939	778	636	512	404	312	235	625	518	423	340	269	208	157	468	388	317	255	202	156	117

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	5,931	4,892	3,976	3,175	2,483	1,893	1,395	1,465	1,208	982	784	613	467	345	836	689	560	447	350	267	197
1∅ 1/O ACSR (6/1)	3,830	3,159	2,567	2,050	1,604	1,222	901	1,290	1,064	865	691	540	412	303	776	640	520	415	325	248	182
1∅ 4/O ACSR (6/1)	2,708	2,233	1,815	1,449	1,134	864	637	1,132	934	759	606	474	361	266	716	590	480	383	300	228	168
1∅ 336.4 ACSR (18/1)	2,229	1,838	1,494	1,193	933	711	524	1,039	857	696	556	435	331	244	677	559	454	363	284	216	159
1∅ 477.0 ACSR (18/1)	1,873	1,544	1,255	1,003	784	598	440	954	787	640	511	400	304	224	640	528	429	343	268	204	151
3∅ 4 ACSR (7/1)	2,915	2,404	1,954	1,561	1,221	930	686	1,167	962	782	625	489	372	274	729	602	489	391	305	233	172
3∅ 1/O ACSR (6/1)	1,883	1,553	1,262	1,008	788	601	443	957	789	641	512	401	305	225	641	529	430	343	269	205	151
3∅ 4/O ACSR (6/1)	1,331	1,098	892	712	557	425	313	790	652	530	423	331	252	186	562	463	377	301	235	179	132
3∅ 336.4 ACSR (18/1)	1,095	903	734	586	459	350	258	701	578	470	375	293	224	165	515	425	345	276	216	164	121
3∅ 477.0 ACSR (18/1)	920	759	617	493	385	294	216	625	515	419	335	262	199	147	473	390	317	253	198	151	111

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	5,641	4,602	3,685	2,885	2,193	1,602	1,105	1,460	1,191	954	747	568	415	286	838	684	548	429	326	238	164
1∅ 1/O ACSR (6/1)	3,643	2,971	2,380	1,863	1,416	1,035	713	1,278	1,043	835	654	497	363	250	775	632	506	396	301	220	152
1∅ 4/O ACSR (6/1)	2,575	2,101	1,682	1,317	1,001	731	504	1,116	910	729	571	434	317	219	712	581	465	364	277	202	139
1∅ 336.4 ACSR (18/1)	2,120	1,729	1,385	1,084	824	602	415	1,021	833	667	522	397	290	200	672	548	439	344	261	191	132
1∅ 477.0 ACSR (18/1)	1,781	1,453	1,164	911	693	506	349	935	763	611	478	364	266	183	634	517	414	324	247	180	124
3∅ 4 ACSR (7/1)	2,773	2,262	1,811	1,418	1,078	788	543	1,151	939	752	589	448	327	226	727	593	475	372	283	206	142
3∅ 1/O ACSR (6/1)	1,790	1,460	1,170	916	696	509	351	938	765	613	480	365	266	184	635	518	415	325	247	180	124
3∅ 4/O ACSR (6/1)	1,266	1,032	827	647	492	360	248	770	628	503	394	300	219	151	554	452	362	283	215	157	108
3∅ 336.4 ACSR (18/1)	1,042	850	681	533	405	296	204	681	556	445	348	265	194	133	506	413	331	259	197	144	99
3∅ 477.0 ACSR (18/1)	875	714	572	448	340	249	171	606	494	396	310	236	172	119	463	378	303	237	180	132	91

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	5,249	4,210	3,294	2,494	1,802	1,211	713	1,401	1,123	879	665	481	323	190	808	648	507	384	277	186	110
1∅ 1/O ACSR (6/1)	3,390	2,718	2,127	1,610	1,163	782	461	1,222	980	767	580	419	282	166	745	598	468	354	256	172	101
1∅ 4/O ACSR (6/1)	2,396	1,922	1,504	1,138	822	553	326	1,063	852	667	505	365	245	144	683	548	429	324	234	158	93
1∅ 336.4 ACSR (18/1)	1,972	1,582	1,238	937	677	455	268	970	778	609	461	333	224	132	644	516	404	306	221	148	87
1∅ 477.0 ACSR (18/1)	1,657	1,329	1,040	787	569	382	225	887	712	557	422	305	205	121	606	486	380	288	208	140	82
3∅ 4 ACSR (7/1)	2,580	2,069	1,619	1,226	886	595	351	1,098	880	689	521	377	253	149	697	559	437	331	239	161	95
3∅ 1/O ACSR (6/1)	1,666	1,336	1,045	791	572	384	226	890	714	558	423	305	205	121	607	487	381	288	208	140	82
3∅ 4/O ACSR (6/1)	1,178	945	739	559	404	272	160	729	584	457	346	250	168	99	527	423	331	251	181	122	72
3∅ 336.4 ACSR (18/1)	969	777	608	461	333	224	132	643	516	404	305	221	148	87	481	386	302	229	165	111	65
3∅ 477.0 ACSR (18/1)	815	653	511	387	280	188	111	571	458	358	271	196	132	78	440	353	276	209	151	101	60

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,797	2,286	1,835	1,442	1,102	811	567	1,119	915	735	577	441	325	227	700	572	459	361	276	203	142
3∅ 1/O ACSR (6/1)	1,806	1,476	1,185	931	712	524	366	918	750	602	473	362	266	186	615	503	404	317	242	179	125
3∅ 4/O ACSR (6/1)	1,277	1,043	838	658	503	370	259	758	620	497	391	299	220	154	539	441	354	278	212	156	109
3∅ 336.4 ACSR (18/1)	1,051	859	690	542	414	305	213	672	549	441	347	265	195	136	494	404	324	255	195	143	100
3∅ 477.0 ACSR (18/1)	883	722	579	455	348	256	179	599	490	393	309	236	174	121	454	371	298	234	179	132	92

GO 95 - Light Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,369	1,858	1,407	1,014	674	384	139	984	771	584	421	280	159	58	621	487	369	266	177	101	36
3∅ 1/O ACSR (6/1)	1,530	1,200	909	655	435	248	90	801	628	476	343	228	130	47	543	426	322	232	154	88	32
3∅ 4/O ACSR (6/1)	1,081	848	642	463	308	175	63	658	516	391	282	187	107	39	473	371	281	203	135	77	28
3∅ 336.4 ACSR (18/1)	890	698	529	381	253	144	52	582	456	346	249	166	94	34	432	339	257	185	123	70	25
3∅ 477.0 ACSR (18/1)	748	587	444	320	213	121	44	518	406	308	222	147	84	30	396	310	235	169	113	64	23

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1,791	1,280	830	437	97	-	-	762	545	353	186	41	-	-	484	346	224	118	26	-	-
3∅ 1/O ACSR (6/1)	1,157	827	536	282	62	-	-	618	442	286	151	33	-	-	421	301	195	103	23	-	-
3∅ 4/O ACSR (6/1)	818	584	379	199	44	-	-	506	362	234	123	27	-	-	366	262	170	89	20	-	-
3∅ 336.4 ACSR (18/1)	673	481	312	164	36	-	-	446	319	207	109	24	-	-	334	239	155	81	18	-	-
3∅ 477.0 ACSR (18/1)	566	404	262	138	30	-	-	396	283	184	97	21	-	-	305	218	141	74	16	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,655	2,144	1,694	1,301	961	670	426	1,175	949	749	575	425	297	188	754	609	481	369	273	190	121
3∅ 1/O ACSR (6/1)	1,715	1,385	1,094	840	620	433	275	945	763	603	463	342	239	152	653	527	416	320	236	165	105
3∅ 4/O ACSR (6/1)	1,212	979	773	594	439	306	194	769	621	491	377	278	194	123	564	455	360	276	204	142	90
3∅ 336.4 ACSR (18/1)	998	806	637	489	361	252	160	677	547	432	332	245	171	109	512	414	327	251	185	129	82
3∅ 477.0 ACSR (18/1)	838	677	535	411	303	212	134	600	484	383	294	217	151	96	467	377	298	229	169	118	75

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,575	2,064	1,614	1,220	880	590	345	1,107	887	694	525	378	254	148	705	565	442	334	241	161	94
3∅ 1/O ACSR (6/1)	1,663	1,333	1,042	788	568	381	223	896	718	561	424	306	205	120	613	491	384	290	210	140	82
3∅ 4/O ACSR (6/1)	1,175	942	737	557	402	269	158	732	587	459	347	250	168	98	532	426	333	252	182	122	71
3∅ 336.4 ACSR (18/1)	967	775	606	458	331	222	130	646	518	405	306	221	148	87	485	388	304	230	166	111	65
3∅ 477.0 ACSR (18/1)	813	652	509	385	278	186	109	573	459	359	272	196	131	77	442	355	277	210	151	101	59

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2,385	1,874	1,424	1,031	691	400	156	1,050	825	627	454	304	176	69	673	529	402	291	195	113	44
3∅ 1/O ACSR (6/1)	1,540	1,210	920	666	446	258	101	845	664	505	365	245	142	55	583	458	348	252	169	98	38
3∅ 4/O ACSR (6/1)	1,089	856	650	471	315	183	71	689	541	411	298	199	116	45	504	396	301	218	146	85	33
3∅ 336.4 ACSR (18/1)	896	704	535	387	260	150	59	606	476	362	262	176	102	40	458	360	274	198	133	77	30
3∅ 477.0 ACSR (18/1)	753	592	450	325	218	126	49	537	422	321	232	156	90	35	418	328	249	180	121	70	27

GO 95 - Heavy Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	662	543	439	348	270	203	148	442	363	293	232	180	136	99	332	272	220	174	135	102	74
1∅ 1/O ACSR (6/1)	611	501	405	321	249	188	137	419	343	277	220	170	129	94	318	261	211	167	130	98	71
1∅ 4/O ACSR (6/1)	560	459	371	294	228	172	125	394	323	261	207	160	121	88	304	249	201	160	124	93	68
1∅ 336.4 ACSR (18/1)	528	433	350	277	215	162	118	378	310	250	198	154	116	84	294	241	195	155	120	90	66
1∅ 477.0 ACSR (18/1)	497	408	329	261	202	153	111	362	297	240	190	147	111	81	284	233	188	149	116	87	64
3∅ 4 ACSR (7/1)	373	306	247	196	152	114	83	291	239	193	153	119	89	65	239	196	158	125	97	73	53
3∅ 1/O ACSR (6/1)	340	279	225	179	138	104	76	271	222	179	142	110	83	61	225	185	149	118	92	69	50
3∅ 4/O ACSR (6/1)	308	253	204	162	125	95	69	250	205	166	131	102	77	56	211	173	140	111	86	65	47
3∅ 336.4 ACSR (18/1)	288	237	191	151	117	89	64	237	194	157	124	97	73	53	201	165	133	106	82	62	45
3∅ 477.0 ACSR (18/1)	270	221	179	142	110	83	60	224	184	149	118	91	69	50	192	157	127	101	78	59	43

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	653	532	426	334	255	188	131	443	361	289	227	173	127	89	335	273	219	171	131	96	67
1∅ 1/O ACSR (6/1)	602	491	393	308	235	173	121	419	341	273	214	163	120	84	321	262	209	164	125	92	65
1∅ 4/O ACSR (6/1)	551	449	360	282	215	158	111	393	321	257	201	153	113	79	306	249	200	156	119	88	62
1∅ 336.4 ACSR (18/1)	519	423	339	265	202	149	104	377	307	246	193	147	108	76	296	241	193	151	115	85	59
1∅ 477.0 ACSR (18/1)	488	398	319	250	191	140	98	360	294	235	184	141	103	73	285	233	186	146	111	82	57
3∅ 4 ACSR (7/1)	365	298	238	187	143	105	73	289	235	188	148	113	83	58	238	194	156	122	93	68	48
3∅ 1/O ACSR (6/1)	333	271	217	170	130	96	67	268	218	175	137	105	77	54	224	183	146	115	87	64	45
3∅ 4/O ACSR (6/1)	302	246	197	154	118	87	61	247	202	161	127	96	71	50	210	171	137	107	82	60	42
3∅ 336.4 ACSR (18/1)	282	230	184	144	110	81	57	234	191	153	120	91	67	47	200	163	131	102	78	57	40
3∅ 477.0 ACSR (18/1)	264	215	172	135	103	76	53	221	180	144	113	86	64	45	191	155	124	98	74	55	38

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	617	494	387	293	213	144	87	425	340	266	202	146	99	60	324	259	203	154	112	76	46
1∅ 1/O ACSR (6/1)	568	455	356	270	196	133	80	401	321	251	190	138	94	57	310	248	194	147	107	72	44
1∅ 4/O ACSR (6/1)	519	416	325	247	179	122	74	376	301	236	179	130	88	53	295	236	185	140	102	69	42
1∅ 336.4 ACSR (18/1)	488	391	306	232	168	114	69	360	288	225	171	124	84	51	284	228	178	135	98	67	40
1∅ 477.0 ACSR (18/1)	459	368	288	218	158	108	65	343	275	215	163	118	80	49	274	220	172	130	95	64	39
3∅ 4 ACSR (7/1)	343	275	215	163	118	80	49	274	219	172	130	94	64	39	228	183	143	108	79	53	32
3∅ 1/O ACSR (6/1)	312	250	196	148	108	73	44	254	203	159	121	88	59	36	214	171	134	102	74	50	30
3∅ 4/O ACSR (6/1)	283	226	177	134	97	66	40	234	188	147	111	81	55	33	200	160	125	95	69	47	28
3∅ 336.4 ACSR (18/1)	264	212	166	126	91	62	37	221	177	139	105	76	52	31	190	153	119	90	66	45	27
3∅ 477.0 ACSR (18/1)	247	198	155	117	85	58	35	209	168	131	99	72	49	30	181	145	114	86	62	42	26

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	560	436	328	233	152	83	26	389	303	228	162	106	58	18	298	232	175	124	81	44	14
1∅ 1/O ACSR (6/1)	515	401	301	214	140	76	24	367	286	215	153	100	54	17	285	222	167	119	77	42	13
1∅ 4/O ACSR (6/1)	470	367	275	196	128	70	21	344	268	201	143	93	51	16	271	211	158	113	74	40	12
1∅ 336.4 ACSR (18/1)	442	345	259	184	120	66	20	329	256	192	137	89	49	15	261	204	153	109	71	39	12
1∅ 477.0 ACSR (18/1)	416	324	243	173	113	62	19	314	244	184	131	85	47	14	252	196	147	105	68	37	12
3∅ 4 ACSR (7/1)	310	241	181	129	84	46	14	249	194	146	104	68	37	11	209	162	122	87	57	31	10
3∅ 1/O ACSR (6/1)	282	220	165	117	77	42	13	231	180	135	96	63	34	11	196	152	114	81	53	29	9
3∅ 4/O ACSR (6/1)	255	199	149	106	69	38	12	213	166	124	89	58	32	10	182	142	107	76	49	27	8
3∅ 336.4 ACSR (18/1)	239	186	140	99	65	35	11	201	157	118	84	55	30	9	174	135	102	72	47	26	8
3∅ 477.0 ACSR (18/1)	223	174	130	93	61	33	10	190	148	111	79	52	28	9	165	129	97	69	45	25	8

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	344	277	217	166	121	84	52	272	219	172	131	96	66	41	225	181	142	108	79	55	34
3∅ 1/O ACSR (6/1)	314	252	198	151	111	76	48	252	203	159	122	89	61	38	211	170	133	102	75	51	32
3∅ 4/O ACSR (6/1)	284	228	179	137	100	69	43	233	187	147	112	82	57	35	197	159	125	95	70	48	30
3∅ 336.4 ACSR (18/1)	266	214	168	128	94	65	40	221	177	139	106	78	54	34	188	151	119	91	67	46	29
3∅ 477.0 ACSR (18/1)	249	200	157	120	88	61	38	209	168	132	100	74	51	32	180	144	113	87	63	44	27

GO 95 - Heavy Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	270	202	143	91	46	8	-	216	162	114	72	37	6	-	180	135	95	60	31	5	-
3∅ 1/O ACSR (6/1)	246	184	130	83	42	7	-	200	150	106	67	34	6	-	169	126	89	57	29	5	-
3∅ 4/O ACSR (6/1)	223	167	118	75	38	7	-	185	138	97	62	31	5	-	158	118	83	53	27	5	-
3∅ 336.4 ACSR (18/1)	209	156	110	70	35	6	-	175	131	92	59	30	5	-	150	112	79	50	26	4	-
3∅ 477.0 ACSR (18/1)	195	146	103	65	33	6	-	165	123	87	55	28	5	-	143	107	75	48	24	4	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	168	100	40	-	-	-	-	135	80	32	-	-	-	-	113	67	27	-	-	-	-
3∅ 1/O ACSR (6/1)	153	91	36	-	-	-	-	125	74	30	-	-	-	-	106	63	25	-	-	-	-
3∅ 4/O ACSR (6/1)	138	82	33	-	-	-	-	115	68	27	-	-	-	-	99	59	23	-	-	-	-
3∅ 336.4 ACSR (18/1)	129	77	31	-	-	-	-	109	65	26	-	-	-	-	94	56	22	-	-	-	-
3∅ 477.0 ACSR (18/1)	121	72	29	-	-	-	-	103	61	24	-	-	-	-	90	53	21	-	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	326	257	196	144	98	60	28	265	209	160	117	80	49	23	224	176	135	99	68	41	19
3∅ 1/O ACSR (6/1)	297	234	179	131	90	55	25	246	194	148	108	74	45	21	210	165	126	92	63	39	18
3∅ 4/O ACSR (6/1)	268	211	162	118	81	49	23	226	178	136	100	68	42	19	195	154	117	86	59	36	17
3∅ 336.4 ACSR (18/1)	251	198	151	111	76	46	22	213	168	128	94	64	39	18	185	146	112	82	56	34	16
3∅ 477.0 ACSR (18/1)	234	185	141	103	71	43	20	201	159	121	89	61	37	17	176	139	106	78	53	32	15

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	310	241	181	128	83	45	13	250	195	146	104	67	36	11	210	163	122	87	56	31	9
3∅ 1/O ACSR (6/1)	282	219	165	117	76	41	12	231	180	135	96	62	34	10	196	153	115	81	53	29	8
3∅ 4/O ACSR (6/1)	255	198	149	106	69	37	11	213	166	124	88	57	31	9	183	142	107	76	49	27	8
3∅ 336.4 ACSR (18/1)	238	185	139	99	64	35	10	201	157	118	84	54	29	9	174	136	102	72	47	25	7
3∅ 477.0 ACSR (18/1)	223	173	130	92	60	33	10	190	148	111	79	51	28	8	166	129	97	69	45	24	7

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	277	208	147	95	50	11	-	225	169	120	77	40	9	-	190	142	101	65	34	8	-
3∅ 1/O ACSR (6/1)	252	189	134	86	45	10	-	208	156	111	71	37	8	-	177	133	94	61	32	7	-
3∅ 4/O ACSR (6/1)	228	171	121	78	41	9	-	191	144	102	66	34	8	-	165	124	88	57	30	7	-
3∅ 336.4 ACSR (18/1)	213	160	113	73	38	9	-	181	136	96	62	32	7	-	157	118	84	54	28	6	-
3∅ 477.0 ACSR (18/1)	199	149	106	68	36	8	-	171	128	91	58	31	7	-	149	112	80	51	27	6	-

GO 95 - Heavy Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	929	770	629	506	400	309	233	621	514	420	338	267	206	155	466	386	315	254	200	155	117
1∅ 1/O ACSR (6/1)	857	710	580	467	369	285	215	588	487	398	320	253	195	147	447	370	303	243	192	149	112
1∅ 4/O ACSR (6/1)	786	651	532	428	338	261	197	553	458	374	301	238	184	139	427	353	289	232	184	142	107
1∅ 336.4 ACSR (18/1)	741	613	501	403	319	246	185	530	439	359	289	228	176	133	413	342	280	225	178	137	103
1∅ 477.0 ACSR (18/1)	697	578	472	380	300	232	175	508	421	344	277	219	169	127	399	331	270	217	172	133	100
3∅ 4 ACSR (7/1)	523	433	354	285	225	174	131	409	338	277	223	176	136	102	335	278	227	183	144	112	84
3∅ 1/O ACSR (6/1)	477	395	323	260	205	159	119	380	315	257	207	164	126	95	316	262	214	172	136	105	79
3∅ 4/O ACSR (6/1)	432	358	293	236	186	144	108	351	291	238	191	151	117	88	296	245	200	161	127	98	74
3∅ 336.4 ACSR (18/1)	405	335	274	220	174	135	101	333	276	225	181	143	111	83	282	234	191	154	122	94	71
3∅ 477.0 ACSR (18/1)	379	314	256	206	163	126	95	315	261	213	171	135	105	79	269	223	182	147	116	90	67

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	925	763	620	495	387	295	217	627	517	420	336	262	200	147	474	391	318	254	198	151	111
1∅ 1/O ACSR (6/1)	852	702	571	456	357	272	200	592	489	397	317	248	189	139	454	375	304	243	190	145	107
1∅ 4/O ACSR (6/1)	780	643	523	417	327	249	183	557	459	373	298	233	178	131	433	357	290	232	181	138	102
1∅ 336.4 ACSR (18/1)	734	606	492	393	307	234	173	533	440	357	285	223	170	125	418	345	280	224	175	134	98
1∅ 477.0 ACSR (18/1)	691	570	463	370	289	221	163	510	421	342	273	214	163	120	404	333	271	216	169	129	95
3∅ 4 ACSR (7/1)	517	426	346	277	216	165	122	408	337	274	219	171	130	96	338	278	226	181	141	108	79
3∅ 1/O ACSR (6/1)	471	388	316	252	197	150	111	379	313	254	203	159	121	89	317	262	213	170	133	101	75
3∅ 4/O ACSR (6/1)	427	352	286	228	179	136	100	350	289	235	187	147	112	82	297	245	199	159	124	95	70
3∅ 336.4 ACSR (18/1)	399	329	268	214	167	127	94	331	273	222	177	139	106	78	283	233	190	152	119	90	67
3∅ 477.0 ACSR (18/1)	373	308	250	200	156	119	88	313	258	210	168	131	100	74	270	223	181	144	113	86	63

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	892	728	583	456	347	253	175	614	501	401	314	239	174	120	468	382	306	239	182	133	92
1∅ 1/O ACSR (6/1)	821	670	536	420	319	233	161	579	473	379	296	225	165	113	448	365	292	229	174	127	88
1∅ 4/O ACSR (6/1)	751	612	490	384	292	213	147	544	443	355	278	211	154	106	426	347	278	218	166	121	83
1∅ 336.4 ACSR (18/1)	706	576	462	361	275	201	138	520	424	340	266	202	148	102	411	336	269	210	160	117	81
1∅ 477.0 ACSR (18/1)	664	542	434	340	258	189	130	497	405	325	254	193	141	97	397	324	259	203	154	113	78
3∅ 4 ACSR (7/1)	496	404	324	253	193	141	97	396	323	259	202	154	112	78	330	269	215	169	128	94	65
3∅ 1/O ACSR (6/1)	451	368	295	231	175	128	88	367	299	240	188	143	104	72	309	252	202	158	120	88	61
3∅ 4/O ACSR (6/1)	409	333	267	209	159	116	80	338	276	221	173	132	96	66	289	236	189	148	112	82	57
3∅ 336.4 ACSR (18/1)	382	312	250	195	149	109	75	320	261	209	164	124	91	63	275	225	180	141	107	78	54
3∅ 477.0 ACSR (18/1)	357	291	233	183	139	101	70	302	247	198	155	118	86	59	262	214	171	134	102	74	51

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	838	672	526	398	288	193	114	582	467	365	277	200	134	79	446	358	280	212	153	103	61
1∅ 1/O ACSR (6/1)	770	618	483	366	264	178	105	549	440	344	261	188	127	75	426	342	268	203	146	98	58
1∅ 4/O ACSR (6/1)	704	565	442	334	242	162	96	514	413	323	244	177	119	70	405	325	254	193	139	93	55
1∅ 336.4 ACSR (18/1)	662	531	416	315	227	153	90	492	394	309	234	169	113	67	391	314	245	186	134	90	53
1∅ 477.0 ACSR (18/1)	623	499	391	296	214	144	85	470	377	295	223	161	108	64	377	302	236	179	129	87	51
3∅ 4 ACSR (7/1)	464	372	291	220	159	107	63	373	299	234	177	128	86	51	312	250	196	148	107	72	42
3∅ 1/O ACSR (6/1)	422	338	265	200	145	97	57	346	277	217	164	119	80	47	293	235	184	139	100	68	40
3∅ 4/O ACSR (6/1)	382	306	240	181	131	88	52	318	255	200	151	109	73	43	273	219	171	130	94	63	37
3∅ 336.4 ACSR (18/1)	357	286	224	170	123	82	48	301	241	189	143	103	69	41	260	208	163	123	89	60	35
3∅ 477.0 ACSR (18/1)	334	268	209	158	115	77	45	284	228	178	135	97	66	39	247	198	155	117	85	57	34

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	496	405	325	256	195	144	100	392	320	257	202	154	114	79	324	265	212	167	128	94	66
3∅ 1/O ACSR (6/1)	452	369	297	233	178	131	92	364	297	239	188	143	106	74	304	249	200	157	120	88	62
3∅ 4/O ACSR (6/1)	409	335	269	211	161	119	83	336	274	220	173	132	97	68	285	233	187	147	112	83	58
3∅ 336.4 ACSR (18/1)	383	313	251	197	151	111	78	318	260	209	164	125	92	64	272	222	178	140	107	79	55
3∅ 477.0 ACSR (18/1)	358	293	235	185	141	104	73	301	246	197	155	118	87	61	259	212	170	133	102	75	52

GO 95 - Heavy Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	423	332	252	181	120	69	25	338	265	201	145	96	55	20	282	221	167	121	80	46	17
3∅ 1/O ACSR (6/1)	386	302	229	165	110	62	23	314	246	186	134	89	51	18	264	207	157	113	75	43	16
3∅ 4/O ACSR (6/1)	349	274	207	149	99	57	20	289	227	172	124	82	47	17	247	193	147	106	70	40	14
3∅ 336.4 ACSR (18/1)	326	256	194	140	93	53	19	273	214	162	117	78	44	16	235	184	140	101	67	38	14
3∅ 477.0 ACSR (18/1)	305	239	181	131	87	49	18	258	203	153	111	74	42	15	224	176	133	96	64	36	13

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	322	230	149	78	17	-	-	259	185	120	63	14	-	-	217	155	100	53	12	-	-
3∅ 1/O ACSR (6/1)	293	209	136	71	16	-	-	240	171	111	58	13	-	-	203	145	94	50	11	-	-
3∅ 4/O ACSR (6/1)	265	189	123	65	14	-	-	221	158	102	54	12	-	-	189	135	88	46	10	-	-
3∅ 336.4 ACSR (18/1)	248	177	115	60	13	-	-	209	149	97	51	11	-	-	180	129	84	44	10	-	-
3∅ 477.0 ACSR (18/1)	232	166	107	56	12	-	-	197	141	91	48	11	-	-	172	123	80	42	9	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	481	388	307	236	174	121	77	392	316	250	192	142	99	63	330	267	211	162	119	83	53
3∅ 1/O ACSR (6/1)	437	353	279	214	158	110	70	362	293	231	177	131	91	58	309	250	197	151	112	78	50
3∅ 4/O ACSR (6/1)	396	319	252	194	143	100	63	333	269	213	163	121	84	53	288	232	183	141	104	73	46
3∅ 336.4 ACSR (18/1)	370	299	236	181	134	93	59	315	254	201	154	114	79	50	274	221	175	134	99	69	44
3∅ 477.0 ACSR (18/1)	345	279	220	169	125	87	55	297	240	189	145	107	75	48	260	210	166	127	94	66	42

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	464	372	291	220	158	106	62	374	300	235	177	128	86	50	314	252	197	149	107	72	42
3∅ 1/O ACSR (6/1)	422	338	264	200	144	97	57	347	278	217	164	118	79	46	294	236	184	139	101	67	39
3∅ 4/O ACSR (6/1)	382	306	239	181	130	87	51	319	256	200	151	109	73	43	274	220	172	130	94	63	37
3∅ 336.4 ACSR (18/1)	357	286	224	169	122	82	48	301	242	189	143	103	69	40	261	209	164	124	89	60	35
3∅ 477.0 ACSR (18/1)	333	267	209	158	114	76	45	285	228	178	135	97	65	38	248	199	156	118	85	57	33

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	432	339	258	186	125	72	28	351	276	209	152	102	59	23	295	232	176	128	86	50	19
3∅ 1/O ACSR (6/1)	393	308	234	170	114	66	26	325	255	194	140	94	54	21	277	217	165	120	80	46	18
3∅ 4/O ACSR (6/1)	355	279	212	153	103	60	23	299	235	178	129	86	50	19	258	202	154	111	75	43	17
3∅ 336.4 ACSR (18/1)	332	261	198	143	96	56	22	282	222	168	122	82	47	18	245	193	146	106	71	41	16
3∅ 477.0 ACSR (18/1)	310	244	185	134	90	52	20	266	209	159	115	77	45	17	233	183	139	101	67	39	15

APPENDIX I. SHORTEST GUY LEAD TO SUPPORT VERTICAL LOAD ON DEADEND STRUCTURES

Shortest Guy Lead to Support Vertical Loads - NESC Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	2	1	1	2	2	3	4	7	1	2	2	4	5	9	19
1∅ 1/O ACSR (6/1)	1	1	1	1	1	2	3	1	1	2	2	3	5	7	1	2	3	4	6	10	21
1∅ 4/O ACSR (6/1)	1	1	1	1	2	2	3	1	1	2	2	3	5	8	2	2	3	4	6	11	23
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	3	4	5	9	2	2	3	4	6	11	25
1∅ 477.0 ACSR (18/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	10	2	2	3	4	7	12	28
3∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	2	2	3	5	8	2	2	3	4	6	10	22
3∅ 1/O ACSR (6/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	9	2	2	3	4	7	11	25
3∅ 4/O ACSR (6/1)	1	1	1	2	3	4	6	1	2	2	3	5	7	11	2	3	3	5	8	13	32
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	7	1	2	3	4	5	8	13	2	3	4	5	8	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	6	9	15	2	3	4	6	9	17	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	1	2	3	1	1	2	2	3	4	7	1	2	3	4	5	9	19
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	3	1	1	2	2	3	5	8	1	2	3	4	6	10	21
1∅ 4/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	3	4	5	9	2	2	3	4	6	11	23
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	4	1	1	2	3	4	6	9	2	2	3	4	6	11	25
1∅ 477.0 ACSR (18/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	10	2	2	3	4	7	12	28
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	8	2	2	3	4	6	10	22
3∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	10	2	2	3	4	7	11	26
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	12	2	3	3	5	8	13	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	13	2	3	4	5	8	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	4	6	9	16	2	3	4	6	9	17	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	2	2	3	5	7	1	2	3	4	6	9	20
1∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	8	2	2	3	4	6	10	21
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	4	1	1	2	3	4	6	9	2	2	3	4	6	11	24
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	10	2	2	3	4	7	11	26
1∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	6	1	2	2	3	4	7	11	2	2	3	5	7	12	29
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	1	2	3	4	5	9	2	2	3	4	6	10	22
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	5	1	2	2	3	4	6	10	2	2	3	5	7	12	26
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	1	2	3	3	5	7	12	2	3	4	5	8	14	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	5	8	14	2	3	4	6	9	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	4	6	9	16	2	3	4	6	9	17	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	8	1	2	3	4	6	9	20
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	4	1	1	2	3	4	5	8	2	2	3	4	6	10	22
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	9	2	2	3	4	6	11	25
1∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	5	1	2	2	3	4	6	10	2	2	3	4	7	12	26
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	4	6	1	2	2	3	4	7	11	2	2	3	5	7	13	29
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	9	2	2	3	4	6	11	23
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	4	6	10	2	2	3	5	7	12	27
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	1	2	3	4	5	8	13	2	3	4	5	8	14	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	6	9	14	2	3	4	6	9	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	4	6	10	17	2	3	4	6	10	17	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	9	2	2	3	4	6	11	24
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	2	2	3	4	7	11	2	2	3	5	7	12	28
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	13	2	3	4	5	8	14	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	6	9	15	2	3	4	6	9	16	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	4	6	10	17	2	3	4	6	10	18	-

Shortest Guy Lead to Support Vertical Loads - NESC Light Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	11	2	3	3	5	7	13	27
3∅ 1/O ACSR (6/1)	1	1	2	3	4	5	7	2	2	3	4	5	8	13	2	3	4	5	8	14	31
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	9	15	2	3	4	6	9	16	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	2	3	5	7	10	17	2	3	4	6	10	18	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	7	11	19	3	3	5	7	11	20	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	5	7	2	2	3	4	5	8	12	2	3	4	5	8	14	29
3∅ 1/O ACSR (6/1)	1	2	2	3	4	6	8	2	2	3	4	6	9	14	2	3	4	6	9	15	-
3∅ 4/O ACSR (6/1)	1	2	3	3	5	7	10	2	2	3	5	7	10	17	2	3	4	6	10	17	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	5	7	11	2	3	4	5	7	11	18	3	3	5	7	11	19	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	5	8	12	21	3	4	5	7	11	21	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	1	2	3	4	5	9	2	2	3	4	6	10	22
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	4	6	10	2	2	3	4	7	11	25
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	1	2	3	3	5	7	12	2	3	3	5	8	13	32
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	5	8	14	2	3	4	5	8	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	4	6	9	16	2	3	4	6	9	17	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	9	2	2	3	4	6	11	23
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	4	7	11	2	2	3	5	7	12	27
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	13	2	3	4	5	8	14	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	8	2	2	3	4	6	9	14	2	3	4	6	9	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	4	6	10	17	2	3	4	6	10	17	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	9	2	2	3	4	6	11	23
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	4	7	11	2	2	3	5	7	12	27
3∅ 4/O ACSR (6/1)	1	1	2	3	4	5	8	2	2	3	4	5	8	13	2	3	4	5	8	14	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	4	6	9	15	2	3	4	6	9	15	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	7	10	2	2	3	4	6	10	17	2	3	4	6	10	17	-

Shortest Guy Lead to Support Vertical Loads - NESC Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	2	3	4	6	9	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	3	4	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	4	1	2	2	3	5	7	11	2	3	4	6	9	16	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	2	2	3	5	7	13	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	7	11	2	3	4	5	8	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	5	2	2	3	4	5	8	13	2	3	4	6	10	18	-
3∅ 4/O ACSR (6/1)	1	1	2	3	3	5	7	2	2	3	4	6	9	16	2	3	5	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	3	3	5	7	11	19	3	4	5	7	12	24	-
3∅ 477.0 ACSR (18/1)	1	2	3	3	5	7	11	2	3	4	5	8	12	23	3	4	5	8	14	29	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	2	2	3	4	6	9	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	10	2	3	4	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	5	7	12	2	3	4	6	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	6	1	2	3	4	5	8	13	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	2	2	3	4	7	11	2	3	4	5	8	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	13	2	3	4	6	10	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	5	8	2	2	3	4	6	10	17	2	3	5	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	3	3	5	7	11	19	3	4	5	7	12	24	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	7	11	2	3	4	5	8	13	24	3	4	5	8	14	29	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	5	7	11	2	3	4	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	3	3	5	8	13	2	3	4	6	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	10	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	6	9	15	2	3	4	6	10	20	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	6	8	14	2	3	4	6	10	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	5	7	10	18	3	3	5	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	3	3	5	7	10	2	3	4	5	7	11	20	3	4	5	8	12	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	6	8	13	25	3	4	6	8	14	29	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	11	2	3	3	5	8	15	-
1∅ 1/O ACSR (6/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	5	8	16	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	13	2	3	4	6	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	18	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	6	9	16	2	3	4	6	10	20	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	3	3	5	7	12	2	3	4	6	9	16	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	5	7	2	2	3	4	6	9	15	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	3	3	5	7	10	18	3	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	5	7	11	2	3	4	5	7	12	21	3	4	5	8	13	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	6	8	13	25	3	4	6	8	14	30	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	13	2	3	4	6	9	17	-
3∅ 1/O ACSR (6/1)	1	1	2	3	3	5	7	2	2	3	4	6	9	15	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	3	3	5	7	11	18	3	4	5	7	12	23	-
3∅ 336.4 ACSR (18/1)	2	2	3	3	5	7	11	2	3	4	5	8	12	21	3	4	5	8	13	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	6	8	14	25	3	4	6	9	15	31	-

Shortest Guy Lead to Support Vertical Loads - NESC Light Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	5	8	2	2	3	4	6	9	15	2	3	5	7	11	19	-
3∅ 1/O ACSR (6/1)	1	2	2	3	5	6	9	2	3	4	5	7	11	18	3	4	5	7	12	22	-
3∅ 4/O ACSR (6/1)	2	2	3	4	5	8	12	2	3	4	5	8	12	22	3	4	6	8	13	26	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	6	9	13	2	3	4	6	9	14	24	3	4	6	9	14	29	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	7	10	15	3	3	5	7	10	16	29	3	5	6	10	16	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	5	6	9	2	3	3	5	7	10	17	3	4	5	7	11	21	-
3∅ 1/O ACSR (6/1)	2	2	3	4	5	7	11	2	3	4	5	8	12	20	3	4	5	8	12	24	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	9	13	2	3	4	6	9	14	24	3	4	6	9	14	28	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	7	10	15	3	3	5	6	9	15	27	3	4	6	9	15	31	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	7	11	17	3	4	5	7	10	17	31	4	5	7	10	17	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	12	2	3	4	5	8	16	-
3∅ 1/O ACSR (6/1)	1	1	2	3	3	5	7	2	2	3	4	6	8	14	2	3	4	6	10	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	5	7	10	18	2	3	5	7	11	22	-
3∅ 336.4 ACSR (18/1)	2	2	3	3	5	7	11	2	3	4	5	7	11	20	3	4	5	7	12	24	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	6	8	13	24	3	4	5	8	14	29	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	3	4	5	8	12	2	3	4	6	9	16	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	5	7	2	2	3	4	6	9	15	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	3	3	5	7	11	18	3	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	5	7	11	2	3	4	5	7	12	21	3	4	5	8	13	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	6	8	14	25	3	4	6	8	14	30	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	13	2	3	4	6	9	16	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	5	8	2	2	3	4	6	9	15	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	5	6	10	2	3	3	5	7	11	19	3	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	5	7	11	2	3	4	5	8	12	21	3	4	5	8	13	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	9	13	2	3	4	6	9	14	26	3	4	6	8	14	30	-

Shortest Guy Lead to Support Vertical Loads - NESC Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	0	1	1	1	1	2	1	1	1	1	2	3	5	1	1	1	2	3	6	15
1∅ 1/O ACSR (6/1)	0	0	1	1	1	1	2	1	1	1	1	2	3	5	1	1	2	2	4	6	17
1∅ 4/O ACSR (6/1)	0	0	1	1	1	2	2	1	1	1	2	2	3	6	1	1	2	2	4	7	20
1∅ 336.4 ACSR (18/1)	0	1	1	1	1	2	3	1	1	1	2	2	4	6	1	1	2	2	4	7	22
1∅ 477.0 ACSR (18/1)	0	1	1	1	1	2	3	1	1	1	2	2	4	7	1	1	2	3	4	8	27
3∅ 4 ACSR (7/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	1	2	2	4	1	1	1	2	3	4	8	1	1	2	3	5	9	27
3∅ 4/O ACSR (6/1)	1	1	1	1	2	3	5	1	1	2	2	3	5	9	1	2	2	3	5	10	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	11	1	2	2	3	6	11	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	13	1	2	3	4	6	13	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	0	1	1	1	1	2	1	1	1	1	2	3	5	1	1	1	2	3	6	15
1∅ 1/O ACSR (6/1)	0	0	1	1	1	2	2	1	1	1	1	2	3	5	1	1	2	2	4	6	17
1∅ 4/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	2	3	6	1	1	2	2	4	7	20
1∅ 336.4 ACSR (18/1)	0	1	1	1	1	2	3	1	1	1	2	2	4	6	1	1	2	2	4	7	22
1∅ 477.0 ACSR (18/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	4	8	27
3∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	1	2	3	5	8	1	1	2	3	5	9	27
3∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	3	5	10	1	2	2	3	5	10	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	11	1	2	2	3	6	11	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	6	13	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	0	1	1	1	2	2	1	1	1	1	2	3	5	1	1	2	2	3	6	16
1∅ 1/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	2	3	6	1	1	2	2	4	7	18
1∅ 4/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	2	4	6	1	1	2	2	4	7	21
1∅ 336.4 ACSR (18/1)	0	1	1	1	1	2	3	1	1	1	2	2	4	7	1	1	2	3	4	8	23
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	2	3	1	1	1	2	3	4	7	1	1	2	3	4	8	27
3∅ 4 ACSR (7/1)	1	1	1	1	2	2	4	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	1	2	3	5	8	1	1	2	3	5	9	28
3∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	3	5	10	1	2	2	3	5	10	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	2	4	6	1	1	2	3	4	6	11	1	2	2	4	6	12	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	7	1	1	2	3	4	7	13	1	2	3	4	6	13	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	2	1	1	1	1	2	3	5	1	1	2	2	3	6	16
1∅ 1/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	2	3	6	1	1	2	2	4	7	18
1∅ 4/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	2	4	6	1	1	2	2	4	7	21
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	2	3	1	1	1	2	3	4	7	1	1	2	3	4	8	23
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	2	4	1	1	1	2	3	4	7	1	1	2	3	4	8	27
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	8	1	1	2	3	5	9	28
3∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	3	6	10	1	2	2	3	5	11	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	11	1	2	2	4	6	12	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	7	1	1	2	3	4	7	13	1	2	3	4	6	14	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	2	4	1	1	1	2	3	4	7	1	1	2	3	4	8	23
3∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	8	1	2	2	3	5	9	29
3∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	10	1	2	2	3	6	11	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	11	1	2	2	4	6	12	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	7	1	1	2	3	4	7	14	1	2	3	4	7	14	-

Shortest Guy Lead to Support Vertical Loads - NESC Medium Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	2	3	5	8	1	2	2	3	5	9	25
3∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	4	5	9	1	2	2	3	5	10	31
3∅ 4/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	11	1	2	3	4	6	12	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	7	1	2	2	3	4	7	13	1	2	3	4	6	13	-
3∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	8	15	1	2	3	4	7	15	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	2	3	5	9	1	2	2	3	5	10	27
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	10	1	2	2	4	6	11	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	7	1	1	2	3	4	7	12	1	2	3	4	6	12	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	7	1	2	2	3	4	7	13	1	2	3	4	7	14	-
3∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	8	16	2	2	3	4	7	16	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	2	4	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	1	2	3	5	8	1	1	2	3	5	9	27
3∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	3	5	10	1	2	2	3	5	10	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	2	4	6	11	1	2	2	3	6	11	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	7	1	1	2	3	4	7	13	1	2	2	4	6	13	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	8	1	1	2	3	5	9	28
3∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	3	6	10	1	2	2	3	5	11	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	11	1	2	2	4	6	12	-
3∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	7	1	1	2	3	4	7	13	1	2	3	4	6	14	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	1	2	3	4	7	1	1	2	3	4	8	22
3∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	2	3	5	8	1	1	2	3	5	9	28
3∅ 4/O ACSR (6/1)	1	1	1	2	2	4	5	1	1	2	2	4	6	10	1	2	2	3	5	11	-
3∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	11	1	2	2	4	6	12	-
3∅ 477.0 ACSR (18/1)	1	1	2	2	3	4	7	1	1	2	3	4	7	13	1	2	3	4	6	14	-

Shortest Guy Lead to Support Vertical Loads - NESC Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	2	1	1	1	2	3	4	7	1	1	2	3	5	10	-
1∅ 1/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	5	11	-
1∅ 4/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	3	5	9	1	2	2	3	6	12	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	2	3	1	1	2	2	3	5	9	1	2	2	3	6	13	-
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	4	6	15	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	4	6	13	-
3∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	12	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	1	2	3	4	6	1	2	2	3	4	7	15	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	17	2	2	3	5	9	23	-
3∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	4	5	9	22	2	2	3	5	10	30	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	5	10	-
1∅ 1/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	8	1	1	2	3	5	11	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	2	3	1	1	1	2	3	5	9	1	2	2	3	6	12	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	2	4	1	1	2	2	3	5	9	1	2	2	3	6	13	-
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	6	11	1	2	2	4	6	15	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	2	3	6	10	1	2	2	4	6	13	-
3∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	12	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	1	2	3	4	6	1	2	2	3	5	7	15	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	7	1	2	2	3	5	8	18	2	2	3	5	9	23	-
3∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	9	1	2	2	4	6	10	23	2	2	3	5	10	30	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	5	10	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	3	1	1	1	2	3	5	8	1	2	2	3	5	11	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	9	1	2	2	3	6	12	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	4	6	13	-
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	3	5	1	1	2	2	4	6	11	1	2	2	4	6	15	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	10	1	2	3	4	6	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	2	4	5	1	1	2	3	4	6	12	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	15	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	18	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	9	1	2	3	4	6	10	23	2	2	4	6	10	30	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	1	2	3	4	7	1	1	2	3	5	10	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	3	1	1	1	2	3	5	8	1	2	2	3	5	11	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	9	1	2	2	3	6	13	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	4	6	14	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	11	1	2	2	4	7	15	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	11	1	2	3	4	6	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	12	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	16	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	18	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	10	1	2	3	4	6	10	23	2	2	4	6	10	31	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	11	1	2	3	4	7	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	17	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	16	2	2	3	5	8	21	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	9	1	2	3	4	6	10	24	2	2	4	6	11	31	-

Shortest Guy Lead to Support Vertical Loads - NESC Medium Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	2	2	3	4	7	12	2	2	3	4	7	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	14	2	2	3	5	8	18	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	3	4	5	9	18	2	2	3	5	9	23	-
3∅ 336.4 ACSR (18/1)	1	1	2	3	4	6	9	1	2	3	4	6	10	21	2	3	4	6	10	26	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	11	2	2	3	4	6	11	26	2	3	4	6	11	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	13	2	2	3	5	8	17	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	1	2	2	3	5	8	15	2	2	3	5	8	19	-
3∅ 4/O ACSR (6/1)	1	1	2	3	4	6	9	1	2	3	4	6	9	19	2	2	4	5	10	24	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	4	6	10	22	2	3	4	6	11	28	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	7	12	2	2	3	4	7	12	28	2	3	4	6	12	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	10	1	2	2	4	6	13	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	6	12	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	15	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	8	18	2	2	3	5	9	23	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	9	1	2	3	4	6	10	23	2	2	3	5	10	30	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	11	1	2	3	4	6	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	12	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	16	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	18	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	10	1	2	3	4	6	10	24	2	2	4	6	10	31	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	11	1	2	3	4	6	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	1	2	2	3	5	8	16	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	10	1	2	3	4	6	10	24	2	2	4	6	10	31	-

Shortest Guy Lead to Support Vertical Loads - NESC Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	5	9	-
1∅ 1/O ACSR (6/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	8	1	1	2	3	5	10	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	2	3	1	1	1	2	3	5	9	1	1	2	3	5	11	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	2	4	1	1	2	2	3	5	10	1	2	2	3	5	12	-
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	6	11	1	2	2	3	6	13	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	5	1	1	2	3	4	6	12	1	2	3	4	7	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	14	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	1	2	2	3	5	8	18	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	22	2	2	3	5	9	23	-
3∅ 477.0 ACSR (18/1)	1	1	2	2	4	6	10	1	2	3	4	6	11	28	2	2	3	5	10	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	1	2	3	1	1	1	2	3	4	7	1	1	2	3	5	9	-
1∅ 1/O ACSR (6/1)	0	1	1	1	2	2	3	1	1	1	2	3	5	8	1	1	2	3	5	10	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	2	4	1	1	1	2	3	5	9	1	1	2	3	5	11	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	3	5	12	-
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	6	11	1	2	2	3	6	13	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	4	5	1	1	2	3	4	6	12	1	2	3	4	6	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	6	1	2	2	3	4	7	14	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	8	18	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	9	1	2	2	3	5	9	22	2	2	3	5	9	23	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	10	1	2	3	4	6	11	28	2	2	3	5	10	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	0	1	1	1	2	2	3	1	1	1	2	3	4	8	1	1	2	3	5	9	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	4	1	1	1	2	3	5	8	1	1	2	3	5	10	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	9	1	1	2	3	5	11	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	3	6	12	-
1∅ 477.0 ACSR (18/1)	1	1	1	1	2	3	5	1	1	2	2	3	6	11	1	2	2	3	6	13	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	14	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	7	1	2	2	3	4	7	15	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	4	5	9	1	2	2	3	5	9	22	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	11	1	2	3	4	6	11	29	2	2	3	5	10	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	1	2	3	4	8	1	1	2	3	5	9	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	4	1	1	1	2	3	5	9	1	1	2	3	5	10	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	3	5	11	-
1∅ 336.4 ACSR (18/1)	1	1	1	1	2	3	4	1	1	2	2	3	5	10	1	2	2	3	6	12	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	2	3	5	1	1	2	2	4	6	12	1	2	2	3	6	13	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	14	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	7	15	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	4	6	9	1	2	2	4	5	10	22	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	11	1	2	3	4	6	11	29	2	2	3	5	10	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	15	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	15	1	2	3	4	7	17	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	8	21	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	4	5	9	1	2	2	4	6	10	23	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	11	1	2	3	4	6	11	29	2	2	4	6	10	31	-

Shortest Guy Lead to Support Vertical Loads - NESC Heavy Loading District

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	7	1	2	2	3	5	7	14	1	2	3	4	7	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	8	17	2	2	3	5	8	18	-
3∅ 4/O ACSR (6/1)	1	1	2	3	4	6	9	1	2	3	4	6	10	21	2	2	3	5	9	22	-
3∅ 336.4 ACSR (18/1)	1	1	2	3	4	6	10	1	2	3	4	6	10	25	2	2	3	5	10	26	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	7	12	2	2	3	4	7	12	32	2	3	4	6	11	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	7	1	2	2	3	5	8	15	2	2	3	5	8	16	-
3∅ 1/O ACSR (6/1)	1	1	2	3	4	5	8	1	2	2	3	5	9	18	2	2	3	5	8	19	-
3∅ 4/O ACSR (6/1)	1	1	2	3	4	6	10	1	2	3	4	6	10	22	2	2	3	5	9	23	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	7	11	2	2	3	4	6	11	26	2	3	4	6	10	27	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	7	13	2	2	3	4	7	12	-	2	3	4	6	11	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	12	1	2	3	4	6	14	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	4	7	15	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	8	19	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	2	4	5	9	1	2	2	3	5	9	22	2	2	3	5	9	23	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	11	1	2	3	4	6	11	28	2	2	3	5	10	29	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	14	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	7	15	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	3	4	6	9	1	2	2	4	5	10	22	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	11	1	2	3	4	6	11	29	2	2	3	5	10	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	1	1	2	3	4	7	13	1	2	3	4	7	14	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	1	2	2	3	5	8	15	1	2	3	4	7	16	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	2	3	5	9	19	2	2	3	5	8	20	-
3∅ 336.4 ACSR (18/1)	1	1	2	3	4	6	9	1	2	2	4	5	10	22	2	2	3	5	9	24	-
3∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	11	1	2	3	4	6	11	29	2	2	3	5	10	30	-

Shortest Guy Lead to Support Vertical Loads - NESC Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	4	1	1	2	2	4	6	11	1	2	3	4	7	18	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	3	4	6	13	1	2	3	4	8	21	-
1∅ 4/O ACSR (6/1)	1	1	1	1	2	3	5	1	1	2	3	4	7	15	1	2	3	4	8	25	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	1	2	3	4	7	17	1	2	3	5	9	28	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	2	4	6	1	2	2	3	5	8	20	2	2	3	5	10	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	7	1	2	2	4	5	9	21	2	2	4	6	10	-	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	8	1	2	3	4	6	11	26	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	1	2	3	4	6	10	2	2	3	4	7	13	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	7	12	2	2	3	5	8	15	-	2	3	4	7	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	8	15	2	2	3	5	9	18	-	2	3	5	8	19	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	2	4	6	12	1	2	3	4	7	18	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	1	2	3	4	6	13	1	2	3	4	8	21	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	3	4	7	15	1	2	3	4	8	25	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	1	2	3	4	8	17	1	2	3	5	9	28	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	2	4	6	1	2	2	3	5	8	20	2	2	3	5	9	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	7	1	2	2	4	5	9	21	2	2	4	6	10	-	-
3∅ 1/O ACSR (6/1)	1	1	2	2	4	5	9	1	2	3	4	6	11	26	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	11	2	2	3	4	7	13	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	7	13	2	2	3	5	8	15	-	2	3	4	7	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	8	16	2	2	3	5	9	18	-	2	3	5	8	19	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	3	4	6	12	1	2	3	4	7	19	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	3	4	7	13	1	2	3	4	8	21	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	3	4	7	16	1	2	3	5	8	25	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	4	6	1	2	2	3	5	8	17	2	2	3	5	9	28	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	6	1	2	2	3	5	9	20	2	2	3	5	10	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	8	1	2	3	4	6	10	21	2	2	4	6	11	-	-
3∅ 1/O ACSR (6/1)	1	1	2	3	4	6	9	2	2	3	4	6	11	27	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	7	11	2	2	3	4	7	13	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	13	2	2	3	5	8	15	-	2	3	5	7	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	2	4	5	8	16	2	2	3	5	9	18	-	2	3	5	8	19	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	1	2	3	4	6	12	1	2	3	4	7	19	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	1	2	3	4	7	14	1	2	3	4	8	21	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	4	5	1	1	2	3	4	7	16	1	2	3	5	8	25	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	6	1	2	2	3	5	8	18	2	2	3	5	9	28	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	7	1	2	2	3	5	9	21	2	2	3	5	10	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	8	1	2	3	4	6	10	22	2	2	4	6	11	-	-
3∅ 1/O ACSR (6/1)	1	1	2	3	4	6	9	2	2	3	4	6	11	27	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	7	12	2	2	3	5	7	13	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	8	13	2	2	3	5	8	15	-	2	3	5	8	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	3	4	5	9	17	2	3	4	5	9	18	-	2	3	5	8	19	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	8	1	2	3	4	6	10	22	2	3	4	6	11	-	-
3∅ 1/O ACSR (6/1)	1	1	2	3	4	6	9	2	2	3	4	6	11	28	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	7	11	2	2	3	5	7	14	-	2	3	4	7	15	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	13	2	2	3	5	8	16	-	2	3	5	8	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	3	4	5	9	16	2	3	4	5	9	19	-	2	3	5	9	19	-	-

Shortest Guy Lead to Support Vertical Loads - NESC Heavy Loading District

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	6	9	2	2	3	4	6	11	24	2	3	4	6	12	-	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	6	11	2	2	3	4	7	12	30	2	3	4	7	13	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	5	8	13	2	2	3	5	8	15	-	2	3	5	8	16	-	-
3∅ 336.4 ACSR (18/1)	1	2	3	4	5	8	15	2	3	4	5	9	17	-	2	3	5	8	17	-	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	10	18	2	3	4	6	10	20	-	2	4	5	9	21	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	6	10	2	2	3	4	7	11	25	2	3	4	7	12	-	-
3∅ 1/O ACSR (6/1)	1	2	2	3	5	7	11	2	2	3	5	7	13	32	2	3	4	7	14	-	-
3∅ 4/O ACSR (6/1)	1	2	3	4	5	8	14	2	3	4	5	8	16	-	2	3	5	8	16	-	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	6	9	16	2	3	4	6	9	18	-	2	3	5	8	18	-	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	10	20	2	3	4	6	10	21	-	3	4	5	9	21	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	8	1	2	3	4	6	9	21	2	2	3	6	10	-	-
3∅ 1/O ACSR (6/1)	1	1	2	3	4	6	9	1	2	3	4	6	11	27	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	7	11	2	2	3	4	7	13	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	13	2	2	3	5	8	15	-	2	3	4	7	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	3	4	5	9	17	2	2	3	5	9	18	-	2	3	5	8	18	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	5	8	1	2	3	4	6	10	22	2	2	4	6	11	-	-
3∅ 1/O ACSR (6/1)	1	1	2	3	4	6	9	2	2	3	4	6	11	27	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	7	12	2	2	3	5	7	13	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	8	14	2	2	3	5	8	15	-	2	3	5	8	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	3	4	5	9	17	2	3	4	5	9	18	-	2	3	5	8	19	-	-

Grade C	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	4	5	8	1	2	3	4	6	10	22	2	2	4	6	11	-	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	6	10	2	2	3	4	6	11	27	2	3	4	6	12	-	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	7	12	2	2	3	5	7	14	-	2	3	4	7	14	-	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	8	14	2	2	3	5	8	15	-	2	3	5	7	16	-	-
3∅ 477.0 ACSR (18/1)	1	2	3	4	5	9	17	2	3	4	5	9	19	-	2	3	5	8	19	-	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Light Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	1	2	3	1	1	2	2	3	5	9	2	2	3	5	7	14	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	3	1	2	2	3	4	6	10	2	2	3	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	4	1	2	2	3	4	7	11	2	3	4	5	8	16	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	2	2	3	5	7	12	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	5	1	2	2	3	5	8	13	2	3	4	6	10	19	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	3	3	5	8	15	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	6	9	16	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	6	10	18	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	7	10	2	3	4	5	7	12	23	3	4	5	8	13	30	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	2	3	4	5	9	2	2	3	5	7	14	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	7	11	2	3	4	5	8	16	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	4	6	1	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	11	2	3	3	5	8	15	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	3	3	5	8	13	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	1	2	3	4	5	8	2	2	3	4	6	9	16	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	5	7	10	19	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	7	11	2	3	4	5	7	12	23	3	4	5	8	13	30	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	11	2	2	3	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	5	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	6	1	2	3	3	5	8	13	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	15	2	3	4	6	10	20	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	3	5	1	2	2	3	5	7	11	2	3	4	5	8	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	8	2	2	3	4	6	10	17	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	10	2	3	3	5	7	11	20	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	7	12	2	3	4	5	8	13	24	3	4	5	8	14	30	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	7	11	2	3	3	5	8	16	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	13	2	3	4	5	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	6	9	15	2	3	4	6	10	20	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	5	1	2	2	3	5	7	12	2	3	4	5	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	3	3	5	7	11	20	3	3	5	7	12	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	25	3	4	5	8	14	31	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	17	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	3	3	5	7	11	20	3	4	5	8	13	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	25	3	4	6	8	14	31	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Light Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	5	7	2	2	3	4	6	9	15	2	3	4	6	10	19	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	5	7	10	17	3	3	5	7	11	22	-
3∅ 4/O ACSR (6/1)	2	2	3	4	5	7	11	2	3	4	5	8	12	21	3	4	5	8	13	26	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	6	8	12	2	3	4	6	8	13	24	3	4	6	8	14	29	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	9	15	2	3	4	6	9	15	29	3	4	6	9	16	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	16	2	3	5	7	11	21	-
3∅ 1/O ACSR (6/1)	2	2	3	4	5	7	10	2	3	4	5	7	11	19	3	4	5	7	12	23	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	8	12	2	3	4	6	8	13	23	3	4	6	8	14	28	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	6	9	14	2	3	4	6	9	14	26	3	4	6	9	15	31	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	7	10	16	3	3	5	7	10	16	31	3	5	6	10	17	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	5	1	2	2	3	4	7	11	2	3	3	5	8	15	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	17	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	3	3	5	7	11	20	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	24	3	4	5	8	13	30	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	12	2	3	4	5	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	1	2	3	3	5	7	10	2	3	3	5	7	11	20	3	3	5	7	12	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	25	3	4	5	8	14	31	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	12	2	3	4	5	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	3	3	5	7	2	2	3	4	6	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	2	2	3	3	5	7	11	2	3	4	5	7	11	21	3	3	5	7	12	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	5	8	13	25	3	4	5	8	14	31	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Light Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	1	2	3	1	1	2	2	3	5	9	2	2	3	5	7	14	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	2	3	1	2	2	3	4	6	10	2	2	3	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	4	1	2	2	3	4	7	11	2	3	4	5	8	16	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	2	3	5	1	2	2	3	5	7	12	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	1	2	3	4	5	1	2	2	3	5	8	13	2	3	4	6	10	19	-
3∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	3	3	5	8	15	-
3∅ 1/O ACSR (6/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	6	9	16	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	5	8	2	2	3	4	6	10	18	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	4	7	10	2	3	4	5	7	12	23	3	4	5	8	13	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	2	3	1	1	2	3	4	5	9	2	2	3	5	7	14	-
1∅ 1/O ACSR (6/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	7	11	2	3	4	5	8	16	-
1∅ 336.4 ACSR (18/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	4	6	1	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	11	2	3	3	5	8	15	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	3	3	5	8	13	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	1	2	3	4	5	8	2	2	3	4	6	9	16	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	5	7	10	19	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	1	2	2	3	5	7	11	2	3	4	5	7	12	23	3	4	5	8	13	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	1	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	6	11	2	2	3	5	8	15	-
1∅ 4/O ACSR (6/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	5	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	6	1	2	3	3	5	8	13	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	15	2	3	4	6	10	20	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	3	5	1	2	2	3	5	7	11	2	3	4	5	8	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	8	2	2	3	4	6	10	17	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	10	2	3	3	5	7	11	20	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	7	12	2	3	4	5	8	13	24	3	4	5	8	14	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	2	2	3	4	1	2	2	3	4	6	10	2	2	3	5	8	14	-
1∅ 1/O ACSR (6/1)	1	1	1	2	2	3	5	1	2	2	3	4	7	11	2	3	3	5	8	16	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	13	2	3	4	5	9	17	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	4	6	2	2	3	4	5	8	14	2	3	4	6	9	18	-
1∅ 477.0 ACSR (18/1)	1	1	2	2	3	5	7	2	2	3	4	6	9	15	2	3	4	6	10	20	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	5	1	2	2	3	5	7	12	2	3	4	5	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	3	3	5	7	11	20	3	3	5	7	12	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	25	3	4	5	8	14	31	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	5	1	2	2	3	5	7	12	2	3	4	6	9	17	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	3	3	5	7	11	20	3	4	5	8	13	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	25	3	4	6	8	14	31	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Light Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	5	7	2	2	3	4	6	9	15	2	3	4	6	10	19	-
3∅ 1/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	5	7	10	17	3	3	5	7	11	22	-
3∅ 4/O ACSR (6/1)	2	2	3	4	5	7	11	2	3	4	5	8	12	21	3	4	5	8	13	26	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	6	8	12	2	3	4	6	8	13	24	3	4	6	8	14	29	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	9	15	2	3	4	6	9	15	29	3	4	6	9	16	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	16	2	3	5	7	11	21	-
3∅ 1/O ACSR (6/1)	2	2	3	4	5	7	10	2	3	4	5	7	11	19	3	4	5	7	12	23	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	8	12	2	3	4	6	8	13	23	3	4	6	8	14	28	-
3∅ 336.4 ACSR (18/1)	2	2	3	4	6	9	14	2	3	4	6	9	14	26	3	4	6	9	15	31	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	7	10	16	3	3	5	7	10	16	31	3	5	6	10	17	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	1	2	3	4	5	1	2	2	3	4	7	11	2	3	3	5	8	15	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	9	18	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	17	2	3	4	7	11	22	-
3∅ 336.4 ACSR (18/1)	1	2	2	3	5	7	10	2	3	3	5	7	11	20	3	3	5	7	12	25	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	24	3	4	5	8	13	30	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	12	2	3	4	5	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	5	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	1	2	3	3	5	7	10	2	3	3	5	7	11	20	3	3	5	7	12	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	5	8	12	2	3	4	5	8	13	25	3	4	5	8	14	31	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	1	2	2	3	5	7	12	2	3	4	5	9	16	-
3∅ 1/O ACSR (6/1)	1	1	2	3	3	5	7	2	2	3	4	6	8	14	2	3	4	6	10	19	-
3∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	4	6	10	18	2	3	5	7	11	23	-
3∅ 336.4 ACSR (18/1)	2	2	3	3	5	7	11	2	3	4	5	7	11	21	3	3	5	7	12	26	-
3∅ 477.0 ACSR (18/1)	2	2	3	4	6	8	13	2	3	4	5	8	13	25	3	4	5	8	14	31	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Heavy Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	2	2	3	4	6	9	19	2	3	4	7	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	2	2	3	4	6	10	22	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	7	11	26	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	2	2	3	5	7	12	29	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	9	2	2	3	5	8	14	-	2	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	5	7	11	2	3	4	6	9	15	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	5	8	13	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	10	17	3	3	5	7	11	22	-	3	5	7	11	24	-	-
3∅ 336.4 ACSR (18/1)	2	3	3	5	7	11	20	3	4	5	8	12	25	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	8	13	25	3	4	5	8	14	31	-	4	5	8	14	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	2	2	3	4	6	10	19	2	3	4	6	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	2	2	3	4	6	10	22	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	2	2	3	4	7	12	26	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	1	2	3	4	5	8	2	2	3	5	7	12	29	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	5	8	14	-	2	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	7	12	2	3	4	6	9	15	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	8	14	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	10	17	3	3	5	7	11	22	-	3	5	7	11	24	-	-
3∅ 336.4 ACSR (18/1)	2	3	3	5	7	11	21	3	4	5	8	12	25	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	8	13	26	3	4	6	8	14	31	-	4	5	8	14	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	2	2	3	4	7	2	2	3	4	6	10	20	2	3	4	7	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	6	11	23	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	1	2	3	4	5	8	2	2	3	5	7	12	27	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	5	7	13	30	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	3	3	5	8	14	-	2	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	12	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	18	3	3	5	7	12	22	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	7	12	21	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	8	14	27	3	4	6	8	14	31	-	4	5	8	14	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	2	2	3	5	7	2	2	3	4	6	10	20	2	3	4	7	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	3	4	5	8	2	2	3	4	7	11	23	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	5	7	12	27	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	5	7	13	31	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	7	11	2	3	4	5	8	14	-	3	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	4	5	7	12	23	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	28	3	4	6	9	15	32	-	4	5	8	14	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	10	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	5	7	10	19	-	3	4	6	10	21	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	4	5	7	12	23	-	3	5	7	12	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	4	5	8	13	29	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	8	14	27	3	4	6	9	15	-	-	4	5	8	14	-	-	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Heavy Loading Zone

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	6	9	14	3	3	5	7	10	18	-	3	4	6	10	20	-	-
3∅ 1/O ACSR (6/1)	2	3	3	5	7	10	17	3	4	5	7	11	20	-	3	5	7	11	23	-	-
3∅ 4/O ACSR (6/1)	2	3	4	5	8	12	21	3	4	5	8	13	25	-	4	5	8	13	27	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	6	8	13	24	3	4	6	9	14	28	-	4	5	8	14	31	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	16	31	3	4	6	9	16	-	-	4	6	9	15	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	3	3	5	7	10	16	3	4	5	7	11	19	-	3	5	7	11	21	-	-
3∅ 1/O ACSR (6/1)	2	3	4	5	7	11	18	3	4	5	8	12	21	-	3	5	7	12	23	-	-
3∅ 4/O ACSR (6/1)	2	3	4	6	8	13	23	3	4	6	8	14	26	-	4	5	8	13	28	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	6	9	14	26	3	4	6	9	15	30	-	4	6	8	14	32	-	-
3∅ 477.0 ACSR (18/1)	3	3	5	7	10	17	-	3	5	6	10	17	-	-	4	6	9	16	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	9	17	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	3	5	7	11	22	-	3	4	7	11	24	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	25	-	3	5	7	12	27	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	27	3	4	6	8	14	31	-	4	5	8	13	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	7	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	4	5	7	12	23	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	28	3	4	6	9	15	32	-	4	5	8	14	-	-	-

Grade A	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	6	8	13	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	7	10	19	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	4	5	7	11	19	3	4	5	7	12	23	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	28	3	4	6	9	15	32	-	4	5	8	14	-	-	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Heavy Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
No kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	1	2	3	4	6	2	2	3	4	6	9	19	2	3	4	7	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	2	3	4	6	2	2	3	4	6	10	22	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	7	11	26	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	1	2	2	3	5	8	2	2	3	5	7	12	29	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	1	2	3	4	6	9	2	2	3	5	8	14	-	2	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	1	2	2	3	5	7	11	2	3	4	6	9	15	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	5	8	13	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	10	17	3	3	5	7	11	22	-	3	5	7	11	24	-	-
3∅ 336.4 ACSR (18/1)	2	3	3	5	7	11	20	3	4	5	8	12	25	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	8	13	25	3	4	5	8	14	31	-	4	5	8	14	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	2	2	3	4	6	2	2	3	4	6	10	19	2	3	4	6	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	2	3	4	7	2	2	3	4	6	10	22	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	1	2	2	3	5	8	2	2	3	4	7	12	26	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	1	2	3	4	5	8	2	2	3	5	7	12	29	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	5	8	14	-	2	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	7	12	2	3	4	6	9	15	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	8	14	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	2	3	4	6	10	17	3	3	5	7	11	22	-	3	5	7	11	24	-	-
3∅ 336.4 ACSR (18/1)	2	3	3	5	7	11	21	3	4	5	8	12	25	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	5	8	13	26	3	4	6	8	14	31	-	4	5	8	14	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	2	2	3	4	7	2	2	3	4	6	10	20	2	3	4	7	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	2	3	5	7	2	2	3	4	6	11	23	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	1	2	3	4	5	8	2	2	3	5	7	12	27	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	9	2	2	3	5	7	13	30	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	6	10	2	3	3	5	8	14	-	2	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	12	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	18	3	3	5	7	12	22	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	7	12	21	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	8	14	27	3	4	6	8	14	31	-	4	5	8	14	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
1∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	1	1	2	2	3	5	7	2	2	3	4	6	10	20	2	3	4	7	12	-	-
1∅ 1/O ACSR (6/1)	1	1	2	3	3	5	8	2	2	3	4	7	11	23	2	3	4	7	13	-	-
1∅ 4/O ACSR (6/1)	1	2	2	3	4	6	9	2	2	3	5	7	12	27	2	3	5	7	14	-	-
1∅ 336.4 ACSR (18/1)	1	2	2	3	4	6	10	2	2	3	5	7	13	31	2	3	5	8	15	-	-
1∅ 477.0 ACSR (18/1)	1	2	2	3	4	7	11	2	3	4	5	8	14	-	3	3	5	8	16	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	4	5	7	12	23	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	28	3	4	6	9	15	32	-	4	5	8	14	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-25 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	10	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	5	7	10	19	-	3	4	6	10	21	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	4	5	7	12	23	-	3	5	7	12	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	4	5	8	13	29	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	8	14	27	3	4	6	9	15	-	-	4	5	8	14	-	-	-

Shortest Guy Lead to Support Vertical Loads - GO 95 - Heavy Loading Zone

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-167 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	6	9	14	3	3	5	7	10	18	-	3	4	6	10	20	-	-
3∅ 1/O ACSR (6/1)	2	3	3	5	7	10	17	3	4	5	7	11	20	-	3	5	7	11	23	-	-
3∅ 4/O ACSR (6/1)	2	3	4	5	8	12	21	3	4	5	8	13	25	-	4	5	8	13	27	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	6	8	13	24	3	4	6	9	14	28	-	4	5	8	14	31	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	16	31	3	4	6	9	16	-	-	4	6	9	15	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 3-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	3	3	5	7	10	16	3	4	5	7	11	19	-	3	5	7	11	21	-	-
3∅ 1/O ACSR (6/1)	2	3	4	5	7	11	18	3	4	5	8	12	21	-	3	5	7	12	23	-	-
3∅ 4/O ACSR (6/1)	2	3	4	6	8	13	23	3	4	6	8	14	26	-	4	5	8	13	28	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	6	9	14	26	3	4	6	9	15	30	-	4	6	8	14	32	-	-
3∅ 477.0 ACSR (18/1)	3	3	5	7	10	17	-	3	5	6	10	17	-	-	4	6	9	16	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-150 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	9	17	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	6	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	3	5	7	11	22	-	3	4	7	11	24	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	25	-	3	5	7	12	27	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	27	3	4	6	8	14	31	-	4	5	8	13	-	-	-

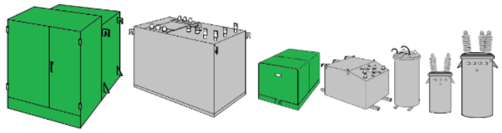
Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-300 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	5	8	13	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	7	10	18	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	3	5	7	11	19	3	4	5	7	12	23	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	28	3	4	6	9	15	32	-	4	5	8	14	-	-	-

Grade B	No Telecommunications							2" Telecommunications							4" Telecommunications						
3∅ 1-500 kVA	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6	H1	1	2	3	4	5	6
1∅ 4 ACSR (7/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 1/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 4/O ACSR (6/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 336.4 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1∅ 477.0 ACSR (18/1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3∅ 4 ACSR (7/1)	2	2	3	4	6	8	13	2	3	4	6	9	16	-	3	4	6	9	18	-	-
3∅ 1/O ACSR (6/1)	2	2	3	4	6	9	15	2	3	4	7	10	19	-	3	4	6	10	20	-	-
3∅ 4/O ACSR (6/1)	2	3	4	5	7	11	19	3	4	5	7	12	23	-	3	5	7	11	25	-	-
3∅ 336.4 ACSR (18/1)	2	3	4	5	8	12	22	3	4	5	8	13	26	-	3	5	7	12	28	-	-
3∅ 477.0 ACSR (18/1)	2	3	4	6	9	14	28	3	4	6	9	15	32	-	4	5	8	14	-	-	-

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.



JULY 21, 2020

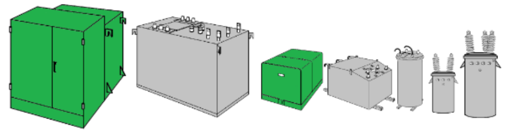
AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Pacific Gas & Electric Company

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.



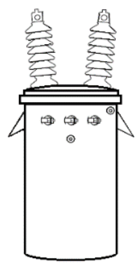
JULY 21, 2020

AUTHORED BY: DAN MULKEY, P.E.

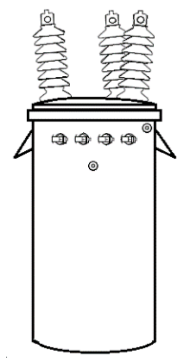
LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Pacific Gas & Electric Company

1. Overhead mounted transformers on wooden utility poles



Single-Phase (1Ø) Overhead Transformer



Three-Phase (3Ø) Overhead Transformer

a. How many man-hours does the typical new transformer installation consume?

Load material, drive to location, set up work area and barricades, drill hole for pole, frame pole, install pole, install ground rods, install ground wire, install anchor, install anchor, install & tension guy, string primary wire, set/check transformer primary voltage, install transformer, connect ground wire, install cutouts, install fuses, string secondary/service wire, install primary jumpers, install secondary jumpers, close cutouts, check service voltages, clean-up area, load scrap, return to yard, clean truck. Standard 3-man line truck can install pole and hang the transformer.

Electric Crew: 2 days x 3 men x 8 hours = 48 man-hours

If replacing the transformer, substitute “replace” for “install” and just do the underlined items:
Electric Crew: 1 day x 3 men x 4 hours = 12 man-hours
Transformer is 25% of new install

b. Does the transformer's weight (lbs.) play a factor?

Yes

- **If yes, under what circumstances?**
  - Contributes to vertical loading on the pole, can require mounting modifications.
  - For 100 kVA and larger, a bank of three 1Ø transformers can exceed max limit of 4000 lb. for pole-bolting and then require platform mounting.
  - Installation in locations which are not truck accessible, such as wet field, mountain side, etc., require manual hauling and lifting of the transformer, which the weight directly impacts.
- **How often do these circumstances occur?**

  Always a factor but seldom (≈ 2%) a significant factor

c. Does the transformer's volume play a factor?

Yes

- **If yes, under what circumstances?**

  Contributes to the wind overturning moment on the pole.

  The taller the transformer, the more space is required on the pole.

- **How often do these circumstances occur?**

  Always a factor but seldom (≈ 2%) a significant factor

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?

Mounting bolt changes from $^5/_8$" to ¾" when over 50 kVA 1Ø or over 75 kVA 3Ø (per IEEE std)

Shear plates for the mounting bolts are required to hang a total load of over 1300 lbs., change at over 2500 lbs. (see appendix). Maximum weight limit of 4000 lbs. Platform construction allows up to 3 transformers @ 4500 lbs. each.

Secondary lead size increases with increasing kVA size

Primary fuse size increases with increasing kVA size

e. For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:

The pole limits do not change with the type of transformer installation

- **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**

  See Table 10 on page 13 and Table 11 on page 14 of 015203, Strength Requirements for Wood Poles (attached)

Vertical Strength Requirements for Poles and Stubs (continued)

Table 10 Allowable Vertical Load at Top of Pole - Pounds (for unguyed poles)

Pole Size (feet)	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
Douglas Fir	"Grade A" Construction [1] (safety factor = 4.0); No Guying							
25	–	–	8,440	6,480	4,890	3,610	2,590	1,890
30	–	–	7,050	5,260	4,020	2,860	2,090	1,550
35	9,570	7,750	5,960	4,500	3,330	2,400	1,680	1,340
40	8,120	6,400	4,960	3,780	2,820	2,060	1,460	1,110
45	7,240	5,560	4,340	3,330	2,400	1,760	1,260	960
50	6,390	4,930	3,880	2,880	2,090	1,540	1,110	–
55	5,570	4,460	3,400	2,540	1,850	1,370	–	–
60	5,070	3,950	3,020	2,260	1,660	1,180	–	–
65	4,530	3,540	2,710	2,040	1,500	1,070	–	–
[illegible]	[illegible]	[illegible]	2,460	1,850	1,360	930	–	–

Vertical Strength Requirements for Poles and Stubs (continued)

Table 11 Allowable Vertical Load at Top of Pole - Pounds (for guyed or effectively restrained poles)

Pole Size (feet)	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
Douglas Fir	"Grade A" Construction [1] (safety factor = 4.0); Guyed or Effectively Restrained							
25	–	–	68,430	52,650	39,780	29,420	21,230	15,560
30	–	–	57,590	43,070	33,010	23,600	17,290	12,990
35	78,410	63,620	49,120	37,250	27,680	20,080	14,160	11,420
40	67,250	53,170	41,430	31,740	23,870	17,550	12,580	9,730
45	60,570	46,750	36,720	28,390	20,710	15,360	11,130	8,700
50	54,130	42,100	33,310	25,040	18,420	13,780	10,080	–
55	47,880	38,620	29,770	22,540	16,710	12,600	–	–
60	44,320	34,890	27,050	20,610	15,390	11,230	–	–
65	40,400	31,950	24,900	19,090	14,350	10,560	–	–
70	32,240	29,590	23,180	17,870	13,520	9,650	–	–
[illegible]	[illegible]	[illegible]	21,770	16,340	12,420	–	–	–

- **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
  See Table 3 on pages 7 and 8 of 015203, Strength Requirements for Wood Poles (attached)

Miscellaneous Tables (continued)

Table 3 Allowable Bending Moment in Pole, New Construction

Pole Length (feet)	Allowable Moment (ft-lb.)							
	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
"Grade A" Construction (safety factor = 4.0)								
25	–	–	18,900	15,500	12,700	10,000	8,000	5,700
30	–	–	23,600	19,050	15,400	12,050	9,350	7,000
35	–	–	27,400	22,500	18,200	13,850	10,750	8,300
40	44,950	37,600	31,050	25,250	20,200	15,850	12,150	8,900
45 [1]	51,700	42,000	34,900	28,600	22,050	17,400	13,400	9,800
50	57,150	46,700	39,000	30,900	23,900	18,950	14,650	–
55	60,900	51,700	41,850	33,250	25,850	20,550	–	–
60	66,850	55,100	44,750	35,650	27,850	21,150	–	–
65	70,950	58,600	47,700	38,200	29,900	22,800	–	–
70	75,100	62,200	50,800	40,750	31,800	23,300	–	–
75	81,850	65,900	53,950	41,700	32,750	–	–	–
80	83,750	69,700	57,000	44,400	33,400	–	–	–
85	88,200	73,600	58,400	45,250	34,000	–	–	–

- **What alternative options would be considered to avoid upgrading the electrical pole?**
  - Install a pad-mount transformer
  - Install a subsurface transformer
  - Install a platform with overhead transformers
  - Interset a new pole for just the transformer

- **Notes:**
  PG&E 015203, Strength Requirements for Wood Poles, uses conservative values for the equipment component of pole loading:

  For wind loading the assumed values used in pole classing are in Table 2 and this is how they compare to some actual transformer designs:

  Wind Load Surface area – Actual vs Design

2006 - 50 kVA 1Ø – 581 lbs., 20" dia. x 25" h tank [PPI]	3.5 ft^2
2009 - 50 kVA 1Ø – 562 lbs., 17.5" dia. x 34" h tank [PPI]	4.13 ft^2 vs 8 ft^2 design
2012 - 50 kVA 1Ø – 602 lbs., 20" dia. x 27" h tank [PPI]	3.75 ft^2
2012 - 50 kVA 1Ø – 609 lbs., 19.25" dia. x 28.8" h tank [HI]	3.85 ft^2
2014 - 50 kVA 1Ø – 562 lbs., 20" dia. x 24" h tank [PPI]	3.3 ft^2
2009 - 100 kVA 1Ø – 892 lbs., 20" dia. x 37" h tank [PPI]	
2012 - 100 kVA 1Ø – 1044 lbs., 22" dia. x 37" h tank [PPI]	5.7 ft^2 vs 10 ft^2design
2009 – 167 kVA 1Ø – 1292 lbs., 22" dia. x 41" h tank [PPI]	
2014 – 167 kVA 1Ø – 1400 lbs., 24" dia. x 41" h tank [PPI]	6.8 ft^2 vs 10 ft^2design
2009 - 300 kVA 3Ø – 2422 lbs., 22" dia. X 69" h tank [PPI]	10.5 ft^2
2013 - 300 kVA 3Ø – 3109 lbs., 24" dia. X 73" h tank [PPI]	12.2 ft^2 vs 12.5 ft^2design

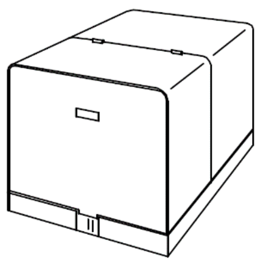
  Overturning Moment:
  In the provided example of a common installation, the transformer contributes 2640 ft.-lbs. (24%) of the total 11,756 ft.-lbs. overturning moment.

  Vertical Strength:
  In the provided example of a common installation, the transformer contributes 538 lbs. (4%) of the total 13,205 lbs. of vertical load

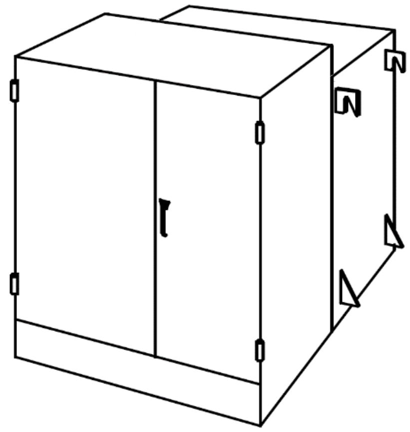
  While transformers typically are not the most critical component in pole classing, they can certainly push a marginally capable pole over the limit.

  Most poles are joint-poles and the communication company facilities often put the most stress on the pole.

2. Surface (pad) mounted transformers



Single-Phase (1Ø) Pad-Mount Transformer



Three-Phase (3Ø) Pad-Mount Transformer

a. How many man-hours does the typical new transformer installation consume?

Load material, drive to location, set up work area and barricades, trench, excavate, install conduits, install pad, install ground rods, install ground wire, restore fill, repave, pull primary cables, pull secondary/service cables, install transformer, label transformer, set/check primary voltage, check/replace transformer fuse size, check operation of switches, install ground bus, connect ground wires, mark and terminate primary cables, mark and terminate secondary cables, connect primary cables, connect secondary cables, energize primary, check service voltages, check phasing, close and lock transformer doors, clean-up area, load scrap, return to yard, clean truck.

Gas Crew[1]: 2 days x 3 men x 8 hours = 48 man-hours
Electric Crew: 2 days x 3 men x 8 hours = 48 man-hours
Equipment Handler[2]: 1 day x 1 man x 4 hours = 4 man-hours
Total = 100 man-hours

If replacing the transformer, substitute "replace" for "install" and just do the underlined items:
Electric Crew: 1x3x4 = 12
Equipment Handler: 1x1x4 = 4
Total 16 man-hours Transformer is 16% of new install

b. Does the transformer's weight (lbs.) play a factor?

Yes

- **If yes, under what circumstances?**
  Pad is designed to a given weight (see weights in section e). Transformers are installed using a crane. The weight capacity of any crane decreases as its reach extends. When the standard

[1] In Gas and Electric service areas, gas crews typically trench, install conduits, and install substructures (enclosures, vaults, pads, etc.)

[2] Electric Crew line trucks have limited crane and cargo capability, most 3-phase pad-mount transformers require an equipment handler

truck crane has insufficient reach or weight then more specialized equipment is employed. Last recourse is outsourcing to someone like Bigge Crane and Rigging Co.

- **How often do these circumstances occur?**
  Standard line truck can handle weight of most single-phase transformers. Equipment handler truck can handle most of the three-phase transformers. The larger three-phase transformers can require outside assistance from crane services.

c. **Does the transformer's volume play a factor?**
Yes

- **If yes, under what circumstances?**
  Transformer must cover cable holes in pad and not extend beyond the pad's perimeter
- **How often do these circumstances occur?**
  Never for transformers that meet the specified dimensions. Exceeding the present maximum dimensions would require a new larger pad with consequent space issues on retrofit replacements[3]

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Primary fuse size increases
Number and/or size of secondary/service cables increase

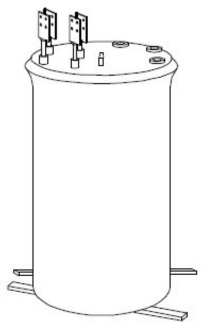
e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad? (W x D x H)**
  100 kVA Style DF-LB 44.0"x44.5"x32.0" vs. 44"x54"x32" so 0"x9.5"x0" or within 18% of allowed volume, 18% of footprint – 1768 lbs. vs 3000 lbs. 59% of allowed.
  167 kVA Style DF-LB 42.0"x51.75"x32.0" vs. 42"x54"x32" so 0"x2.25"x 0" or within 4% of allowed volume, 4% of footprint – 2107 lbs. 3000 lbs. 70% of allowed.
  300 kVA IIE-LB 73.3"x59.8"x72.0" vs 76"x60"x77" so 2.7"x0.2"x5.0" or within 10% of allowed volume, 4% of footprint – 4637 lbs. vs 5800 lbs. 80% of allowed.
  2500 kVA IIE-LB 89.0"x87.9"x93.3" vs. 89"x96"x96" so 0.0"x8.1"x2.7" or within 11% of allowed volume, 8% of footprint – 15330 lbs. vs 16000 lbs. 96% of allowed.
  2955/3325 kVA IIG 88.0"x96.0"x87.4" vs. 89"x104"x96" so 1.0"x8.0"x8.6" or within 17% of allowed volume, 9% of footprint – 17386 lbs. vs 22000 lbs. 79% of allowed.

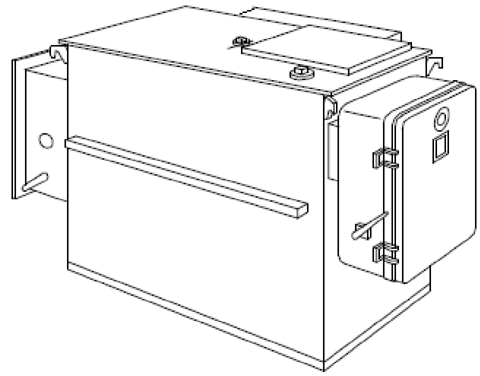
- **What alternative options would be considered to avoid replacement of the supporting pad?**
  Residential service – install an additional transformer and splitting the load.
  Non-Residential – create new pad design with larger footprint – major issue when replacing existing transformers[3]

[3] Approving a larger sized transformer means that the pad must be replaced as well as the transformer upon failure of the old smaller sized transformers.

3. Underground vault (installed below grade) installed transformers



Single-Phase (1Ø) Vault Transformer



Three-Phase (3Ø) Vault Transformer

a. How many man-hours does the typical new transformer installation consume?

Load material, drive to location, set up work area and barricades, trench, excavate, install vault, install ground rods, install ground wire, install conduits, restore fill, repave, pull primary cables, pull secondary/service cables, install transformers, label transformers, set/check primary voltage, check/replace transformer fuse size, check operation of switches, install ground bus, connect ground wires, mark and terminate primary cables, mark and terminate secondary cables, connect primary cables, connect secondary cables, energize primary, check service voltages, install enclosure cover, clean-up area, load scrap, return to yard, clean truck.

Note: Vaults are confined workspaces and require a qualified person to remain outside the space when anyone is inside.

Gas Crew[4]: 3 days x 3 men x 8 hours = 72 man-hours
Electric Crew: 3 days x 4 men x 8 hours = 96 man-hours
Equipment Handler[5]: 2 days x 1 men x 4 hours = 8 man-hours
Total = 176 man-hours

If replacing the transformer, substitute "replace" for "install" and just do the underlined items:
Elec Crew: 2x4x4 = 32
Equipment Handler: 2x1x4 = 8
Total 40 man-hours Transformer is 23% of new install

[4] In Gas and Electric service areas, gas crews typically trench, install conduits, and install substructures (enclosures, vaults, pads, etc.)
[5] Electric Crew line trucks have limited crane and cargo capability, most 3-phase transformers require an equipment handler

b. **Does the transformer's weight (lbs.) play a factor?**
Yes

- **If yes, under what circumstances?**
1Ø - The transformer must be moved by hand within the vault
3Ø - Transformer is dropped through removable cover using a crane. The weight capacity of any crane decreases as its reach extends. When the standard truck crane has insufficient reach or weight then more specialized equipment is employed. Last recourse is outsourcing to someone like BIGGE Crane and Rigging Co.
- **How often do these circumstances occur?**
1Ø - Every installation
3Ø - Standard line truck can handle weight of the smaller kVAs. Material handler truck can handle most of the larger kVAs. Rarely, the largest require outside assistance from crane services.

c. **Does the transformer's volume play a factor?**
Yes

- **If yes, under what circumstances?**
The transformer must fit through the vault access portal and fit within the vault interior.
- **How often do these circumstances occur?**
Never for transformers that meet the specified dimensions. Exceeding the present maximum dimensions would require a new access portal and vault interior with consequent space issues on retrofit replacements.[6]

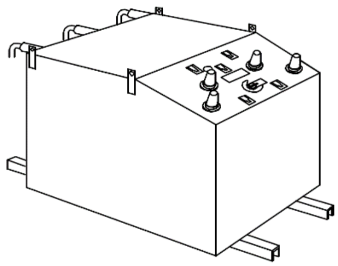
d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Primary fuse increases
Secondary cables increase in size and/or number

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

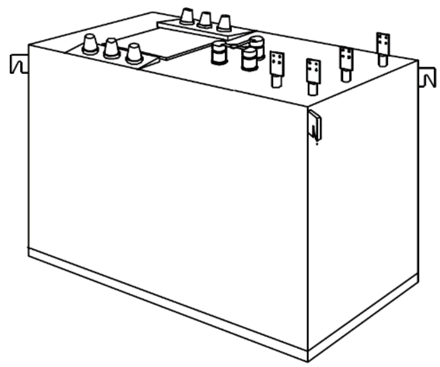
- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**
1Ø – sized to fit through 39" manhole – width and depth must fit within a 39" circle, height ≤ 58" – 250 kVA Subway-LB, 35.5" diameter, 52.4" high so 4.4" diameter, 5.6" height – within 25% of allowed volume
3Ø – 2000 kVA Network, (W x L x H), 77"x 117"x90" vs. 63.3"x96.2"x90" so 13.7"x20.8"x0.0" height – within 32% of allowed volume
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**
New vault or new vault cover with larger transformer access portal.

[6] Approving a larger sized transformer means that the vault must be replaced as well as the transformer upon failure of the old smaller sized transformers.

4. Underground subsurface (installed at grade) installed transformers



Single-Phase (1Ø) Subsurface Transformer



Three-Phase (3Ø) Subsurface Transformer

a. How many man-hours does the typical new transformer installation consume?

Load material, drive to location, set up work area and barricades, trench, excavate, install enclosure, install ground rods, install ground wire, install conduits, restore fill, repave, pull primary cables, pull secondary/service cables, install transformer, label transformer, set/check primary voltage, check/replace transformer fuse size, check operation of switches, install ground bus, connect ground wires, mark and terminate primary cables, mark and terminate secondary cables, connect primary cables, connect secondary cables, energize primary, check service voltages, install enclosure cover, clean-up area, load scrap, return to yard, clean truck.

Gas Crew[7]: 2 days x 3 men x 8 hours = 48 man-hours
Electric Crew: 2 days x 3 men x 8 hours = 48 man-hours
Equipment Handler[8]: 1 day x 1 men x 4 hours = 4 man-hours
Total = 100 man-hours

If replacing the transformer, substitute "replace" for "install" and just do the underlined items:
Electric Crew: 1x3x4 = 12
Equipment Handler: 1x1x4 = 4
Total 16 man-hours Transformer is 16% of new install

b. Does the transformer's weight (lbs.) play a factor?

Typically, no. Transformers are installed using a crane. The weight capacity of any crane decreases as its reach extends. When the standard truck crane has insufficient reach or weight then more specialized equipment is employed. Last recourse is outsourcing to someone like BIGGE Crane and Rigging Co.

[7] In Gas and Electric service areas, gas crews typically trench, install conduits, and install substructures (enclosures, vaults, pads, etc.)

[8] Electric Crew line trucks have limited crane and cargo capability, most 3-phase subsurface transformers require an equipment handler

- **If yes, under what circumstances?**
  Impaired access to the enclosure can cause severe issues with crane capacity
- **How often do these circumstances occur?**
  Rarely, probably <1%

c. **Does the transformer's volume play a factor?**
Yes. New 1Ø transformers are installed in a 4'x6'6"x5' enclosure. Previous 40+ years of installations are installed in 3'x5'x5' enclosures. 3Ø transformers are installed in 4'6"x8'6"x7'6" enclosures.

- **If yes, under what circumstances?**
  Utility specified maximum dimensions are set to the maximum size that can be installed in the respective enclosure.
- **How often do these circumstances occur?**
  Never for transformers that meet the specified dimensions. Exceeding the present maximum dimensions would require a new larger enclosure with consequent space issues on retrofit replacements.[9]
  New builds of 1Ø 167 kVA transformer had design issues with the latest DOE efficiency requirements. This was solved by taking the natural ester insulating fluid above the historically used 65°C rise limit and closer to the 75°C temperature rise limit allowed by the PG&E material specification.

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
3Ø: Primary fuse size increases
1Ø & 3Ø: Number and/or size of secondary or service cables increase

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure? (W x L x H)**
  1Ø Horizontal, 100 kVA: 23.5"x44.0"x31.5" vs 23.5"x48"x31.5" so 0.0"x4.0"x0.0" – within 8% of allowed volume
  3Ø UCD, 300 kVA: 37.82"x78.94"x78.46" vs 39"x80"x79" so 1.18"x1.06"x0.54" – within 5% of allowed volume
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**
  1Ø – replace enclosure with next larger standard size. Major cost impact and is not always physically possible due to other installations.
  3Ø – design, have manufactured & supplied a new even larger enclosure. As existing concept requires cover to be operationally accessible by a single person, an even larger enclosure would be problematic.
  Residential subdivision – split the load by installing an additional transformer

[9] Approving a larger sized transformer means that the enclosure must be replaced as well as the transformer upon failure of the old smaller sized transformers.

Summary

Overhead Transformers:

- Transformer is typically ≈ 25% of a new install.
- Beginning at 1Ø 100 kVA, a bank of three can exceed the 4000 lb. limit for pole bolting
- For pole classing, the transformer typically is not the principle force. It can, however, push a marginally capable pole over the limit and require pole replacement. Pole replacements at time of transformer replacements are commonplace.

Pad-mounted Transformers:

- Transformer is typically ≈ 16% of a new install.
- Present design is 96% of maximum allowed volume.
- Weight is 96% of allowed

Underground (Vault) Transformers

- Transformer is typically ≈ 23% of a new install.
- Present design is 75% of maximum allowed volume.
- Weight is not critical

Underground Subsurface Transformers

- Transformer is typically ≈ 16% of a new install.
- Present design is 95% of maximum allowed volume.
- Weight is not critical

Appendix

PG&E's distribution transformer use is generally governed by:

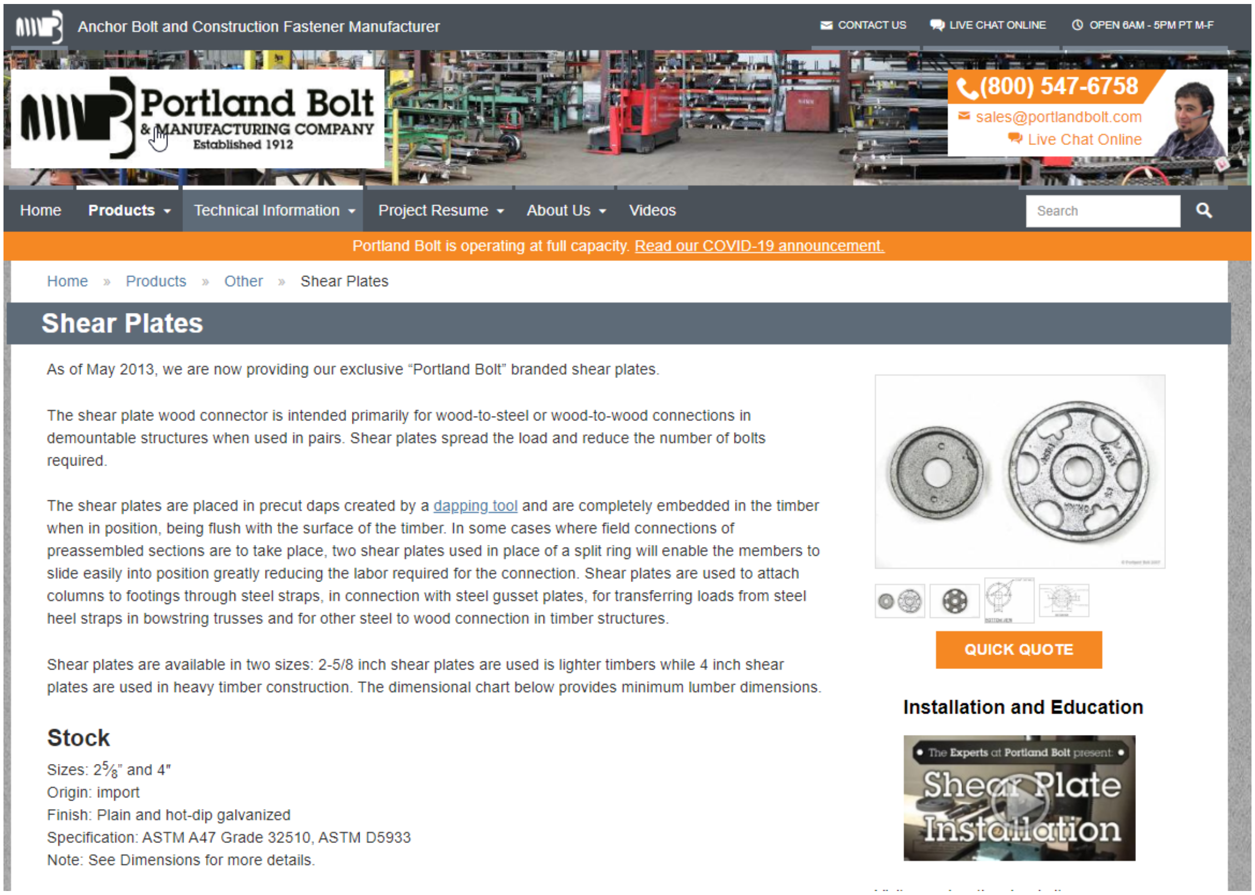
1) Overhead installations are the cheapest and should be used whenever feasible.
2) Since the early 1960's by state law, service to new residential subdivisions (defined as 5 lots or more) and new commercial developments must be underground. Exception is now limited to use of already existing overhead pole lines. (Previously there was an exception for certain large lot residential subdivisions.)
3) Typical residential service (1Ø 3-wire, 120/240 V) is from 1Ø pad-mount transformer, or 1Ø subsurface transformer in a 3'x5' (recently upgraded to 4'x6'6") subsurface enclosure when applicant pays the cost differential. Sizes used are 25, 50, 75, or 100 kVA. In subdivisions, one transformer will serve multiple customers through a secondary system. Economics favor adding customers until a 100 kVA transformer maxes out on the 6.5-volt drop limit or the 8-volt flicker drop limit. The ultimate 167 kVA transformer size is reserved for use only when an existing transformer gets into trouble.
4) Typical commercial/industrial service (3Ø 4-wire, 120/208 V or 277/480 V) is from a 3Ø pad-mount transformer (75 kVA through 3325 kVA) or a 3Ø subsurface UCD transformer (150 kVA through 1000 kVA) when the applicant pays the cost differential. Groups of several small commercial establishments may have their services combined and supplied by a single transformer. However, for the most part, each transformer serves only a single customer. The concrete pad is sized to accept the largest transformer needed to serve the full capacity of the customer's main switch (max size permitted is 4000 A at 480 V). Service cables are installed to meet the main switch capacity. The initial transformer size, however, is often reduced to match the expected peak load.
5) Typical agricultural service (3Ø 4-wire, 120/208 V or 277/480 V) is from a 3Ø overhead transformer (45 kVA through 300 kVA) sized to match the pump hp installed. 3Ø pad-mount transformers are used when transformer size exceeds capability of a 300 kVA overhead transformer.
6) Special cases:
   a) Duplex transformers, pad-mount or subsurface, are used to supply 4-wire, 3Ø, 120/240 volt service
   b) 3Ø network transformers are used in downtown San Francisco or Oakland

SHEAR PLATES

Table 6 of PG&E 056425, Overhead Transformer Installation, details the use of shear plates:

Table 6 Use of Shear Plates

Transformer Weight	Shear Plates
0 – 1,300 lbs.	None Required
1,301 – 2,500 lbs.	2-5/8" Shear Plates On Top and Bottom Through Bolts
2,501 – 4,000 lbs.	4" Shear Plates On Top and Bottom Through Bolts


Anchor Bolt and Construction Fastener Manufacturer

CONTACT US LIVE CHAT ONLINE OPEN 6AM - 5PM PT M-F

Portland Bolt & MANUFACTURING COMPANY Established 1912

(800) 547-6758
sales@portlandbolt.com
Live Chat Online

Home Products Technical Information Project Resume About Us Videos Search

Portland Bolt is operating at full capacity. Read our COVID-19 announcement.

Home » Products » Other » Shear Plates

Shear Plates

As of May 2013, we are now providing our exclusive "Portland Bolt" branded shear plates.

The shear plate wood connector is intended primarily for wood-to-steel or wood-to-wood connections in demountable structures when used in pairs. Shear plates spread the load and reduce the number of bolts required.

The shear plates are placed in precut daps created by a dapping tool and are completely embedded in the timber when in position, being flush with the surface of the timber. In some cases where field connections of preassembled sections are to take place, two shear plates used in place of a split ring will enable the members to slide easily into position greatly reducing the labor required for the connection. Shear plates are used to attach columns to footings through steel straps, in connection with steel gusset plates, for transferring loads from steel heel straps in bowstring trusses and for other steel to wood connection in timber structures.

Shear plates are available in two sizes: 2-5/8 inch shear plates are used is lighter timbers while 4 inch shear plates are used in heavy timber construction. The dimensional chart below provides minimum lumber dimensions.

Stock

Sizes: 2⅝" and 4"
Origin: import
Finish: Plain and hot-dip galvanized
Specification: ASTM A47 Grade 32510, ASTM D5933
Note: See Dimensions for more details.

QUICK QUOTE

Installation and Education

The Experts at Portland Bolt present: Shear Plate Installation

Shear Plate Timber Connectors

What are shear plates?

Shear plate timber connectors (also called timber washers) are round, malleable iron discs that are inserted in precut grooves and are completely imbedded in the timber when in position, being flush with the surface of the timber. Shear plates are intended primarily for wood-to-steel connections or for wood-to-wood connections in demountable structures when used in pairs.

Shear plates provide greater load-carrying capacity in shear than can be achieved by a bolt alone. Simply put, shear plate timber connectors are devices for increasing the strength of the joints in timber construction and reduce the number of bolts required.

MULKEY ENGINEERING INC.

CONTACT: DAN MULKEY
707-776-7346
MULKEYENGINEERING@YAHOO.COM

Prepared by: NIB1

PG&E	**STRENGTH REQUIREMENTS FOR WOOD POLES**	**015203**

Department:	Electric T&D	**Section:**	T&D Engineering and Technical Support
Approved by:	C. D. Poston (CDP4) C D Poston	**Date:**	05-28-04

Rev. #05: This document replaces PG&E Document 015203, Rev. #04. For a description of the changes, see Page 18.

Purpose and Scope

This document provides data for:

Determining the minimum class pole that will meet the strength requirements for new installations.

Determining whether an existing pole has adequate strength for additional conductor or equipment loads.

General Information

1. All poles shall meet the minimum strength requirements at the ground line as shown on Pages 2 through 4. Equipment poles, in addition to meeting the ground line strength requirements, must also meet the vertical strength requirements as shown on Pages 11 and 12. Poles and stubs supported by down guys shall also meet the minimum vertical strength requirements. Poles and stubs supported by sidewalk guys shall also meet the minimum strength requirements listed on Pages 16 and 17.
2. The average span S used in the formulas is taken as half the sum of the two adjacent spans supported by the pole concerned.
3. Minimum top circumference requirements of G.O. 95, for all conditions except “Grade A” construction in the Heavy Loading District, may be met by using either Class 5 poles or Class 6 poles with Class 5 tops. Class 6 poles with Class 5 tops are purchased in 35-foot, 40-foot, and 45-foot lengths and should be used where applicable (see example on Page 3).
4. For existing poles, the safety factor (SF) for “Grade A” construction may be reduced as low as 2.67, and for “Grade B”, as low as 2.0. Deterioration must be included. Use “Grade C” construction tables (SF = 2.0) for existing “Grade B” construction. For strength limits for vertical load, other than “Grade A” construction, multiply the “Grade A” figures in Table 10 on Page 13 and Table 11 on Page 14 by the following factors: SF = 3.0, use 1.33; SF = 2.67, use 1.5; SF = 2.0, use 2.0. For SF = 2.67 for sidewalk guy horizontal tension, multiply the “Grade A” figures in Table 12 (Pages 16 and 17) by 1.5. Refer to UO Standard S2325 for determining of any loss of strength due to internal decay. For reduction in the allowable moment due to reduced ground line circumference caused by deterioration or damage, see Note 13 on Page 3.
5. For 44–115 kV lines, use Document 032550 for transverse loading limitations and pole setting requirements.

References	**Document**
Capacitors for Distribution Lines	028425
Construction Requirements for Pole Line Guys	022178
Distribution Transformer Requirements - Single-Phase Overhead Type	034963
Distribution Transformer Requirements - Three-Phase Overhead Type	040950
Mud Sills for Wood Pole Lines	030109
Overhead Transformer Installation	056425
Reinforcement and Straightening of Poles - Unbalanced Strain or Soft Soil	023058
Transverse Loading Design Criteria for 44–115 kV Pole Lines	032551
Transverse Loading Limitations, Design Criteria for 44–115 kV Pole Lines	032550
UO Standard S2325, “Wood Poles - Testing, Restoring, Reinforcing, and Reusing”	S2325

Strength Requirements at Ground Line

Bending and Overturning Moments

1. The allowable bending moments in Table 3 and Table 4 on Pages 7 and 8 are average values for all types of poles. The figures shown are net values, having been corrected for wind pressure on the pole itself. The figures also include some assumptions. The allowable bending moments are based on poles of minimum 6 feet from butt circumference for each class. These figures may be increased slightly for poles that have larger than minimum ground line diameters (see Note 13 on Page 3).
2. The allowable overturning moments in Table 6 on Page 9 apply to all classes and lengths of poles, as the resistance to overturning is primarily a function of depth of setting and type of soil. These values are also net, having been corrected for the wind load on the pole. Since the soil resistance is extremely variable, these figures should not be taken as definite fixed limits, but rather as a guide, to be modified as experience and as judgement regarding the class of soil indicate. Past experience indicates that the values given in the table are conservative for ordinary firm soils.

Poles Not Supporting Equipment

3. Compute the bending or overturning moment "M" due to wind loading from the formula, M = N x H x S x P, where:

   N = Number of conductors
   H = Height of conductor above ground
   S = Average span length (see Note 2 on Page 1)
   P = Wind load per lineal foot of wire (see Table 1 on Pages 5 and 6)

4. Where conductors of different size and/or of different height are involved, compute the moment M separately for each conductor level and size, and add the results together to obtain the total moment.
5. When unguyed taps, such as services or slack spans exist, consider the moment created by these attachments. Estimate the tension in the attachment (slack conductors are usually installed at less than 75 pounds tension) and multiply by the height of the attachment to obtain the moment. Note that attachments in the opposite direction of the maximum moment reduce the moment (i.e., services in opposite directions cancel each other).
6. It is not necessary to calculate a bending/overturning moment for poles that are restrained from falling due to guys or conductors under tension. Examples of this would be 4-way corner poles, guyed line and buck or corner poles, and guyed angle poles where the line angle is 10 degrees or more. Slack spans are not an effective restraint. Vertical load may still need to be calculated.
7. From Table 3 on Pages 7 and 8, determine the class of pole having adequate strength at the ground line to withstand the total moment.

Equipment Poles

8. To allow for wind loading on the equipment and bending due to the eccentric weight of the equipment, increase the bending moment calculated according to Note 3 as follows:

   A. Equipment in "Normal" position

   Increase the calculated bending moment due to wind on the wires by a wind load of 8 pounds per square foot x the total projected area of equipment exposed to the wind (in square feet) x the distance from the ground to the top of the equipment (in feet). Note that for multiple transformer installations and capacitors, only the side profile is used to determine the surface area exposed to the wind. In other words, for an open delta bank, use only the surface area of the largest transformer. The other transformer is considered sheltered by the larger unit.

   B. Equipment in "Buck" position

   Increase the sum of the calculated bending moment due to wind on the wires and on any projected area of equipment by the moment of the equipment itself from Table 9 on Page 10. In the buck position, deduct the area of the pole that shelters any equipment from the wind. Use the area of all the transformers in a multiple transformer installation in determining the equipment area. In calculating the area of the pole, use the height of the equipment and the diameter of the pole at that level.

Strength Requirements at Ground Line (continued)

Soil Conditions

9. If the poles are to be set in *firm* soil, use the setting depths from the "Soil" column of Table 5 on Page 9 unless the computed moment exceeds the allowable moment for that depth as given in Table 5 on Page 9. In which case, increase the setting depth sufficiently so that the allowable moment exceeds the computed moment.
10. If the poles are to be set in *soft* ground, use short spans and/or increased setting depths to avoid overturning due to wind loading. Under such conditions, unduly short spans or deep settings may often be avoided by rocking-in or keying of poles (Document 023058), by use of mud sills (Document 030109), or possibly by storm guys (Document 022178).
11. All backfill soil shall be firmly tamped.
12. If the poles are to be set in rock, use the setting depths from the last column of Table 5 on Page 9. These setting depths should be adequate to develop the full strength of the pole. (When poles are set in rock, leave a solid collar of rock around the pole at the surface of the ground.)

Loading Capacity Adjustment

13. For a given pole, it may be necessary to adjust the allowable bending moment or vertical load capacity based on the actual groundline circumference to account for larger than minimum dimensions or for reduced dimensions due to damage. To adjust capacity, the following method, which makes some assumptions, may be used to provide reasonable results.
    A. Measure the circumference at groundline (or at the damage point if above groundline).
    B. For the existing pole and for the next larger (or smaller) class pole, obtain:
        1. The minimum circumference 6 feet from the butt per the ANSI O5.1 dimensions in UO Standard S2325.
        2. The allowable bending moment or vertical load from the appropriate table.
    C. Using the values obtained, interpolate to obtain the adjusted allowable capacity.
    D. Example:
    Existing Douglas fir 45' Class 5 "Grade A" pole. Measured groundline circumference = 34". Per ANSI, the minimum circumference of a 45' Class 5 DF pole is 32.5" and a 45' Class 4 DF pole is 35". From Table 4 on Page 8, for existing 45' Class 5 and 4 "Grade A" poles, the capacity is 22,000 ft-lbs. and 28,150 ft-lbs. respectively.

$$\text{Adjusted Capacity} = 22{,}000 + \left(\frac{34 - 32.5}{35 - 32.5}\right)(28{,}150 - 22{,}000) =$$

$$= 22{,}000 + \left(\frac{1.5}{2.5}\right)(6{,}150) = 22{,}000 + 3{,}690 = 25{,}690 \text{ ft-lbs.}$$

Example

14. The following example illustrates the calculation of moments and use of the various tables:

Given: Light Loading District, "Grade A" construction, firm soil, 45-foot pole, average span 150 feet.

Primary Conductors – 2-#4 Bare ACSR

N = 2
H = 39 feet
S = 150 feet
P = 0.167 (lb. per lineal foot from Table 1 on Page 5)
Moment of Primary Conductors = M_p = 2 x 39 x 150 x 0.167 = 1,954 ft-lbs.

Secondary Conductors – 3-1/0 Bare All-Aluminum

N = 3
H = 31 feet
S = 150 feet
P = 0.246 (lb. per lineal foot from Table 1 on Page 5)
Moment of Secondary Conductors = M_s = 3 x 31 x 150 x 0.246 = 3,432 ft-lbs.

Telephone Conductors - 1.0" Diameter Cable (5/16" Messenger)

N = 1
H = 23 feet
S = 150 feet
P = 0.876 (lb. per lineal foot from Table 1 on Page 5)
Moment of Telephone Conductors = M_t = 1 x 23 x 150 x 0.876 = 3,022 ft-lbs.

Total Moment at Ground Line = $M_p + M_s + M_t$ = 1,954 + 3,432 + 3,022 = 8,408 ft-lbs.

Strength Requirements at Ground Line (continued)

15. Pole Not Supporting Equipment

    A. From Table 3 on Page 7, "Grade A" construction, 45-foot pole, a Class 6 pole (9,800 ft-lb. allowable moment) is indicated.

       1. From Table 5 on Page 9, the normal setting depth in firm soil for a 45-foot pole is 6 feet. From Table 6 on Page 9, the allowable overturning moment with a 6 foot setting depth is 20,000 ft-lbs. This is ample to develop the allowable bending moment in the pole.

16. Transformer Pole

    A. Transformer in "Normal" position (1 – 75 kVA 3∅ transformer)

       1. Calculated moment due to wind on wires = 8,408 ft-lbs.
          Total projected area = 10 square feet
          Height above ground = 33 feet
       2. Total Moment = 8,408 + (8 x 10 x 33) = 11,048 ft-lbs.
       3. From Table 3 on Page 7, "Grade A" construction, 45-foot pole, a Class 5 pole (13,400 ft-lbs. allowable moment) is required.
       4. From Table 5 on Page 9, setting depth = 6 feet

    B. Transformer in "Buck" position (1 – 75 kVA transformer)

       1. Weight = 1,000 pounds (from Table 9 on Page 10, Moment = 1,000 x 1.5 = 1,500 ft-lbs.).
       2. Projected area of transformer sheltered by pole = 3 sq. ft., Moment = (8 x 3 x 33) = 792 ft-lbs.
       3. Total moment = 11,048 + 1,500 – 792 = 11,756 ft.-lbs.
       4. From Table 3 on Page 7, "Grade A" construction, 45-foot pole, a Class 5 pole (13,400 ft-lb. allowable moment) is required.
       5. From Table 5 on Page 9, setting depth = 6 feet.

17. Note: Equipment poles selected by the method shown on this document will meet the minimum strength requirements at the ground line. Vertical strength requirements of equipment poles must be checked separately as shown on Pages 11 through 15 of this document.

Miscellaneous Tables

Notes

1. Table 1 through Table 9 on Page 10 are for use in determining the required class of pole and pole setting depth to withstand the transverse (wind) loads specified by G.O. 95, without the use of side guys.
2. Regardless of bending moment, all poles shall meet minimum top circumference requirements for the appropriate loading district and grade of construction as shown in Table 7 on Page 10.

   Table 8 on Page 10 is for use in relating minimum top circumferences shown in Table 7 on Page 10 to ANSI pole class.

Table 1 Wind Load on Wires [1]

Conductor		Wind Load – P Pounds per Lineal Foot		
Type	Size AWG or CM	Light Loading	Intermediate Loading	Heavy Loading
Bare Copper	6	0.108	0.331	0.581
	4	0.155	0.366	0.616
	2	0.195	0.396	0.646
	1/0	0.245	0.434	0.684
	2/0	0.276	0.457	0.707
	3/0	0.309	0.482	0.732
	4/0	0.351	0.513	0.764
	250,000	0.383	0.537	0.787
600 V Weatherproof Copper	6	0.168	0.376	0.626
	4	0.215	0.411	0.661
	2	0.255	0.441	0.691
	1/0	0.329	0.497	0.747
	3/0	0.394	0.545	0.795
	250,000	0.483	0.612	0.862
Bare ACSR	4	0.167	–	0.629
	2	0.217	0.413	0.663
	1/0	0.265	0.449	0.699
	4/0	0.375	0.531	0.782
Bare All-Aluminum	1/0	0.246	–	–
	3/0	0.309	–	–
	4/0	0.348	0.511	–
	266,800	0.391	–	–
	336,400	0.444	–	–
	397,500	0.483	0.612	0.862
	715,500	0.649	0.737	0.987
600 V Weatherproof All-Aluminum	4	0.215	–	–
	2	0.255	0.441	0.691
	1/0	0.329	0.497	0.747
	4/0	0.428	0.571	0.821
	397,500	0.583	0.687	0.937

[1] To determine “P” for wires not shown in Table 1, use the following formulas:
Light Loading P = wire diameter in inches x 0.667. Intermediate Loading P = (wire diameter in inches + 0.5) x 0.50.
Heavy Loading P = (wire diameter in inches + 1) x 0.50.
For communication cables, use the cable diameter plus the messenger diameter as the wire diameter.

Miscellaneous Tables (continued)

Table 1 Wind Load on Wires [1] (continued)

Conductor		Wind Load – P Pounds per Lineal Foot		
Type	Size AWG or CM	Light Loading	Intermediate Loading	Heavy Loading
Triplex ACSR Aerial Cable	1/0	0.654	0.740	0.990
	4/0	0.880	0.910	1.160
Quadriplex ACSR Aerial Cable	1/0	0.747	0.810	1.060
	4/0	0.987	0.990	1.240
Triplex AWAC Aerial Cable	1/0	1.04	1.03	1.28
	4/0	1.23	1.18	1.43
Quadruplex AWAC Aerial Cable	1/0	1.35	1.26	1.51
	4/0	1.63	1.48	1.73
Tree Wire	6 Cu	0.328	0.496	–
	4 ACSR	0.387	0.540	0.790
	1/0 Al	0.468	0.601	0.851
	4/0 Al	0.572	0.679	0.929
	397 Al	0.705	0.778	1.029
Communications Cables		Light Loading [2]	Intermediate Loading [2]	Heavy Loading [2]
Bare Steel (0.109” Dia.)		0.073	0.305	0.555
0.50” Cable (1/4” messenger)		0.500	0.625	0.875
0.75” Cable (1/4” messenger)		0.667	0.750	1.00
1.00” Cable (5/16” messenger)		0.875	0.906	1.16
1.50” Cable (5/16” messenger)		1.21	1.16	1.41
1.90” Cable (3/8” messenger)		1.52	1.39	1.64
2.50” Cable (7/16” messenger)		1.96	1.72	1.97
2.80” Cable (3/8” messenger)		2.14	1.84	2.09

1 To determine “P” for wires not shown in Table 1, use the following formulas:
Light Loading P = wire diameter in inches x 0.667. Intermediate Loading P = (wire diameter in inches + 0.5) x 0.50.
Heavy Loading P = (wire diameter in inches + 1) x 0.50.
For communication cables, use the total diameter of the cable assembly. This may or may not include an external messenger, depending on the cable construction, and may include multiple, bundled cables.

2 Values in this table include wind load on messenger.

Table 2 Wind Load on Equipment [1]

Type of Equipment	Surface Area – Feet^2 (square feet)		Wind Load – Pounds	
	Cylindrical (projected)	Flat	Light Loading District	Intermediate/Heavy Loading District
Transformers Through 50 kVA	8	–	64	48
Transformers 75 kVA - 167 kVA	10	–	80	60
Transformers Over 167 kVA, Regulator	12.5	–	100	75
Capacitor Bank, Fixed	–	2	26	20
Capacitor Bank, Switched	1	2	34	26
Recloser, Sectionalizer	–	3	39	30
Luminaire, Street Light	1	–	8	6

1 This may be used to estimate wind load on equipment when dimensions of actual equipment to be used are not known. Wind load shown is based on a horizontal wind pressure of 8 lbs./ft.^{2} of the projected area on cylindrical surfaces and 13 lbs./ft.^{2} on flat surfaces in the light loading district; 6 lbs./ft.^{2} on the projected area of cylindrical surfaces and 10 lbs./ft.^{2} on flat surfaces in the intermediate and heavy loading district.

Miscellaneous Tables (continued)

Table 3 Allowable Bending Moment in Pole, New Construction

Pole Length (feet)	Allowable Moment (ft-lb.)							
	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
"Grade A" Construction (safety factor = 4.0)								
25	–	–	18,900	15,500	12,700	10,000	8,000	5,700
30	–	–	23,600	19,050	15,400	12,050	9,350	7,000
35	–	–	27,400	22,500	18,200	13,850	10,750	8,300
40	44,950	37,600	31,050	25,250	20,200	15,850	12,150	8,900
45 [1]	51,700	42,000	34,900	28,600	22,050	17,400	13,400	9,800
50	57,150	46,700	39,000	30,900	23,900	18,950	14,650	–
55	60,900	51,700	41,850	33,250	25,850	20,550	–	–
60	66,850	55,100	44,750	35,650	27,850	21,150	–	–
65	70,950	58,600	47,700	38,200	29,900	22,800	–	–
70	75,100	62,200	50,800	40,750	31,800	23,300	–	–
75	81,850	65,900	53,950	41,700	32,750	–	–	–
80	83,750	69,700	57,000	44,400	33,400	–	–	–
85	88,200	73,600	58,400	45,250	34,000	–	–	–
90	92,800	75,100	59,550	47,350	34,500	–	–	–
95	97,750	79,250	60,750	47,750	–	–	–	–
100	99,750	80,850	64,200	49,700	–	–	–	–
105	103,850	81,950	65,000	49,500	–	–	–	–
"Grade B" Construction (safety factor = 3.0)								
25	–	–	25,650	21,100	17,300	13,700	11,000	7,900
30	–	–	32,150	26,000	21,150	16,650	12,950	9,750
35	–	–	37,500	30,950	25,150	19,250	15,000	12,000
40	61,500	51,550	42,750	34,950	28,150	22,250	17,200	12,800
45	70,950	57,850	48,300	39,800	30,900	24,600	19,150	14,350
50	78,750	64,650	54,250	43,250	33,800	27,050	21,200	–
55	84,350	71,900	58,550	46,900	36,850	29,650	–	–
60	93,000	77,050	63,000	50,700	40,050	30,900	–	–
65	99,150	82,450	67,650	54,700	43,350	33,650	–	–
70	105,500	88,000	72,500	58,800	46,700	34,900	–	–
75	115,450	93,800	77,500	60,800	48,500	–	–	–
80	118,900	99,750	82,700	65,150	50,100	–	–	–
85	125,900	105,950	85,250	67,200	51,650	–	–	–
90	133,150	109,000	87,700	71,250	53,200	–	–	–
95	141,100	115,850	90,450	73,000	–	–	–	–
100	145,200	119,300	96,400	76,350	–	–	–	–
105	152,550	121,900	98,550	77,600	–	–	–	–

[1] Underlined figures are used in the example (Note 14 through Note 16 on Pages 3 and 4).

Miscellaneous Tables (continued)

Table 3 Allowable Bending Moment in Pole (continued)

Pole Length (feet)	Allowable Moment (ft-lb.)							
	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
"Grade C" Construction (safety factor = 2.0)								
25	–	–	39,100	32,300	26,550	21,100	16,950	12,300
30	–	–	49,300	40,000	32,650	25,750	20,250	15,350
35	–	–	57,750	47,850	38,950	30,100	23,600	18,700
40	94,550	79,500	66,150	54,300	44,000	35,000	27,350	20,700
45	109,400	89,600	75,100	62,150	48,650	39,000	30,700	23,400
50	121,900	100,550	84,800	68,050	53,600	43,300	34,300	–
55	131,200	112,300	92,000	74,250	58,900	47,800	–	–
60	145,200	121,000	99,600	80,800	64,450	50,400	–	–
65	155,550	130,100	107,550	87,650	70,300	55,350	–	–
70	166,300	139,600	115,900	94,900	76,550	58,100	–	–
75	182,600	149,550	124,600	99,000	80,000	–	–	–

Table 4 Allowable Bending Moment in Existing "Grade A" Pole

Pole Length (feet)	Allowable Bending Moment (ft-lb.)							
	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
Existing "Grade A" Construction (safety factor = 2.67)								
25	–	–	28,950	23,900	19,600	15,550	12,450	9,000
30	–	–	36,400	29,450	24,000	18,900	14,750	11,150
35	–	–	42,500	35,150	28,550	21,950	17,150	13,500
40	69,650	58,450	48,500	39,750	32,050	25,400	19,700	14,750
45	80,450	65,700	54,900	45,300	35,300	28,150	22,000	16,600
50	89,400	73,500	61,800	49,400	38,700	31,050	24,450	–
55	95,900	81,900	66,850	53,650	42,300	34,150	–	–
60	105,900	87,950	72,050	58,150	46,050	35,700	–	–
65	113,100	94,250	77,500	62,850	50,050	39,000	–	–
70	120,550	100,750	83,200	67,750	54,100	40,650	–	–
75	132,050	107,550	89,150	70,250	56,300	–	–	–
80	136,250	114,650	95,350	75,450	58,350	–	–	–
85	144,550	121,950	98,500	78,050	60,400	–	–	–
90	153,100	125,750	101,650	83,100	62,450	–	–	–
95	162,550	133,900	105,150	85,450	–	–	–	–
100	167,700	138,300	112,300	89,550	–	–	–	–
105	176,450	141,650	115,150	91,500	–	–	–	–

Miscellaneous Tables (continued)

Table 5 Minimum Pole Setting Depths

Length of Pole (feet)	Setting Depth (feet)	
	In Soil [1]	In Rock
25	4-1/2	3
30	5	3
35	5	3-1/2
40	5-1/2	3-1/2
45	6	4
50	6-1/2	4
55–60	7	4-1/2
65–70	7-1/2	5
75	8	5-1/2
80	8	6
85	8-1/2	6
90	9	6
95	9-1/2	6-1/2
100	10	6-1/2
105	10-1/2	6-1/2

[1] All backfill soil shall be firmly tamped.

Table 6 Allowable Overturning Moment (firm soil)

Setting Depth (feet)	Allowable Moment (ft-lb.)
4-1/2	7,200
5	9,500
5-1/2	14,000
6	20,000
6-1/2	29,000
7	39,000
7-1/2	54,000
8	72,000
8-1/2	100,000
9	137,000
9-1/2	185,000
10	250,000
10-1/2	345,000

Miscellaneous Tables (continued)

Table 7 Minimum Required Pole Top Circumference - (G.O. 95)

Loading District		Grade of Construction A (inches)	Grade of Construction B and C (inches)
Light	Rural	19 [1]	16
	Urban		19
Heavy	Rural	22	19
	Urban		

[1] Underlined figures are used in the example (Note 14 through Note 16 on Pages 3 and 4).

Table 8 Minimum Top Circumference for Wood Poles (ANSI standard)

Pole Class	Minimum Top Circumference (inches)
7	15
6 [1]	17 (19) [2]
5	19
4	21
3	23
2	25
1	27
H1	29
H2	31

[1] Underlined figures are used in example (Note 14 through Note 16 on Pages 3 and 4).

[2] Class 6 poles in lengths of 35 feet, 40 feet, and 45 feet are purchased with Class 5 (19" minimum) tops and should be used to meet the requirements of Table 7, when applicable.

Table 9 Equipment Moment Multiplier [1]

Multiplier	Equipment Type
1.5	1∅ Transformers Through 50 kVA, Open Delta Transformer Banks, 3∅ Transformers Through 75 kVA
1.75	1∅ Transformers 75 kVA and Above, 3-1∅ Transformer Banks
2.0	3∅ Transformers 112.5 kVA and Above, Regulators, Capacitors
2.67	Reclosers, Sectionalizers

[1] Multiplier used per Note 8B on Page 2, Note 9 on Page 11, and the example in Note 16 on Page 4.

Vertical Strength Requirements for Poles and Stubs

Vertical Load

1. Vertical load is the sum of all the weight on a pole, including conductors, ice, equipment, and the vertical load component from down guys.
2. The vertical strength of a pole differs depending on how it is restrained. Guyed and effectively restrained poles have more capability than tangent line poles. See Table 10 on Page 13 and Table 11 on Page 14. The allowable vertical loads shown in these tables are net values, having been corrected for the weight of the pole itself. Allowable loads are based on the minimum dimensions for each class.
3. The considerations when selecting poles due to vertical load are:
   A. The maximum tension of the down guys attached.
   B. The "lead over height" ratio of the guys.
   C. The weight of equipment on the pole.
   D. The height of the guy and equipment attachments.
4. The weight of crossarms, insulators, brackets, and conductors all contribute to vertical load. However, their weight is usually small in comparison to down guy and equipment loads, so it will normally not be necessary to estimate their weight unless a pole's vertical load is close (150-200 pounds) to an upper strength limit.
5. Transformer weight is indicated on the nameplate. If it is not possible to check the actual weight, approximate weights are shown in Document 034963 for single-phase and in Document 040950 for three-phase transformers. However, these weights take into consideration older transformers that are much heavier than those currently purchased.
6. Capacitor bank approximate weights are shown in Document 028425.
7. Recloser and sectionalizer weight is approximately 950 pounds.
8. For calculating ice weight on conductors, use the following formulas: Intermediate Loading, W_I = 0.311 (2d + 0.5); Heavy Loading, W_I = 0.311 (2d + 1), where d = conductor diameter.
9. For guyed poles that also have an equipment moment over 2,500 ft-lbs., in addition to the normal vertical load calculations for guyed poles, calculate a vertical load without the guys and compare this result to the unguyed vertical capabilities in Table 10 on Page 13. Size the pole for the worst case scenario between the two methods.
10. For heavy equipment that may create bending in a pole, a sidewalk guy assembly, as shown in Figure 1 on Page 12, may be used to offset the bending moment of the equipment. Use the non-guyed vertical capabilities. In this case, do not calculate a vertical load from the guy as it is minimal.
11. Poles that support only guy wires (guy stubs) are part of the guying system and are therefore sized by "Grade C" construction criteria for poles (safety factor = 2).

Minimum Pole Class

12. Determine the minimum class of pole or stub that may be used to support vertical load as follows:
    A. Vertical Load Component of Down Guy

    Obtain the vertical component of the guy strain using one of the formulas shown below:
    1. Vertical Load = T_G x Cos [Arc Tan (L/H)].
    2. Vertical Load = T x H_C/L.

    Where T_G = guy tension; L = lead, pole to anchor; H = height of guy attachment; T = total horizontal tension of all individual maximum dead-end or side strain tensions at their height above ground; H_C = height of conductor above ground.

    B. Equivalent Vertical Load

    All vertical loads need to be converted to their equivalent load at the top of the pole. Calculate an "Equivalent Load Factor" for each attachment using the following formula: ELF = $(H/H_P)^2$, where H = height of attachment of the guy or equipment, and H_P = height of the pole top.

    C. Total Vertical Load

    The total vertical load at the top of the pole is the sum of all the equivalent vertical loads obtained in (B) above.

    D. From Table 10 on Page 13 and Table 11 on Page 14, determine the minimum required class of pole to withstand this total vertical load.

Vertical Strength Requirements for Poles and Stubs (continued)

Sample Calculation

13. The following example illustrates the use of the tables.

Given:

A. "Grade A" construction.
B. 45-foot pole set 6 feet deep.
C. Joint anchor, 15-foot lead.
D. Power guy, 13.7M strain, attachment to pole at 36-foot level.
E. Telephone guy, 9M strain, attachment to pole at 20-foot level.
F. 800-lb. transformer, top bolt attached at 32-foot level.

Calculations to find vertical load on pole at guy attachments:

1. Power guy: Cos [Arc Tan (15/36)] = 0.923.
   Vertical load = 13,700 pounds x 0.923 = 12,646 pounds at 36-foot level.
2. Telephone guy: Cos [Arc Tan (15/20)] = 0.800
   Vertical load = 9,000 pounds x 0.800 = 7,200 pounds at 20-foot level.

Calculations to find equivalent vertical load at top of pole.

3. Power guy: ELF = $(36/39)^2$ = 0.852
   Equivalent power load = 12,646 x 0.852 = 10,774 pounds at pole top.
4. Telephone guy: ELF $(20/39)^2$ = 0.263.
   Equivalent telephone load = 7,200 x 0.263 = 1,893 pounds at pole top.
5. Transformer: ELF = $(32/39)^2$ = 0.673.
   Equivalent transformer load = 800 x 0.673 = 538 pounds.

Determination of class of pole required.

6. Total equivalent vertical load at pole top = 10,774 + 1,893 + 538 = 13,205 pounds.
7. From Table 11 on Page 14, a Class 3 western red cedar or Class 4 Douglas fir pole is required.

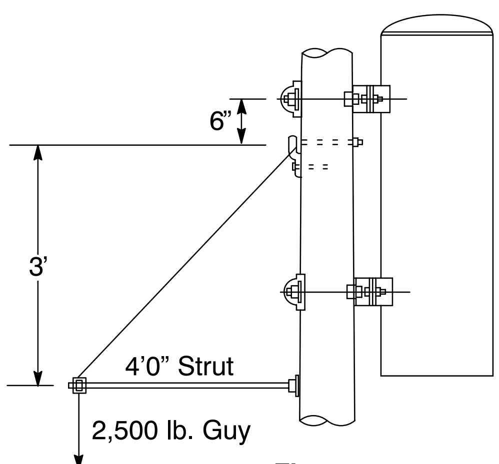


Figure 1
Sidewalk Guy to Offset Bending

Vertical Strength Requirements for Poles and Stubs (continued)

Table 10 Allowable Vertical Load at Top of Pole - Pounds (for unguyed poles)

Pole Size (feet)	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
Douglas Fir	"Grade A" Construction [1] (safety factor = 4.0); No Guying							
25	–	–	8,440	6,480	4,890	3,610	2,590	1,890
30	–	–	7,050	5,260	4,020	2,860	2,090	1,550
35	9,570	7,750	5,960	4,500	3,330	2,400	1,680	1,340
40	8,120	6,400	4,960	3,780	2,820	2,060	1,460	1,110
45	7,240	5,560	4,340	3,330	2,400	1,760	1,260	960
50	6,390	4,930	3,880	2,880	2,090	1,540	1,110	–
55	5,570	4,460	3,400	2,540	1,850	1,370	–	–
60	5,070	3,950	3,020	2,260	1,660	1,180	–	–
65	4,530	3,540	2,710	2,040	1,500	1,070	–	–
70	4,090	3,200	2,460	1,850	1,360	930	–	–
75	3,830	2,910	2,240	1,630	1,200	–	–	–
80	3,390	2,660	2,050	1,490	1,050	–	–	–
85	3,110	2,450	1,820	1,320	920	–	–	–
90	2,870	2,180	1,620	1,210	810	–	–	–
95	2,630	2,000	1,420	1,060	–	–	–	–
100	2,340	1,770	1,300	930	–	–	–	–
105	2,180	1,590	1,160	820	–	–	–	–
Western Red Cedar	–	–	–	–	–	–	–	–
25	–	–	7,150	5,360	4,120	2,950	2,170	1,620
30	–	–	5,840	4,440	3,320	2,420	1,720	1,380
35	8,080	6,430	4,860	3,740	2,830	2,000	1,440	1,170
40	7,010	5,450	4,170	3,240	2,380	1,700	1,240	970
45	6,180	4,840	3,730	2,830	2,100	1,520	1,110	830
50	5,410	4,260	3,310	2,520	1,890	1,320	980	–
55	4,830	3,820	2,990	2,290	1,660	1,220	–	–
60	4,370	3,480	2,730	2,040	1,480	1,090	–	–
65	4,010	3,210	2,450	1,830	1,340	990	–	–
70	3,710	2,890	2,220	1,670	1,220	870	–	–
75	3,370	2,640	2,020	1,520	1,120	–	–	–
80	3,170	2,410	1,860	1,400	1,000	–	–	–
85	2,910	2,220	1,710	1,250	920	–	–	–
90	2,690	2,060	1,590	1,160	820	–	–	–
95	2,490	1,900	1,420	1,040	–	–	–	–
100	2,240	1,760	1,320	960	–	–	–	–
105	2,100	1,600	1,190	860	–	–	–	–

[1] To obtain allowable loads for other safety factors, multiply the allowable loads shown above by 1.33 for SF = 3.0, 1.5 for SF = 2.67, or 2 for SF = 2.0.

Vertical Strength Requirements for Poles and Stubs (continued)

Table 11 Allowable Vertical Load at Top of Pole - Pounds (for guyed or effectively restrained poles)

Pole Size (feet)	Class H2	Class H1	Class 1	Class 2	Class 3	Class 4	Class 5	Class 6
Douglas Fir	"Grade A" Construction [1] (safety factor = 4.0); Guyed or Effectively Restrained							
25	–	–	68,430	52,650	39,780	29,420	21,230	15,560
30	–	–	57,590	43,070	33,010	23,600	17,290	12,990
35	78,410	63,620	49,120	37,250	27,680	20,080	14,160	11,420
40	67,250	53,170	41,430	31,740	23,870	17,550	12,580	9,730
45	60,570	46,750	36,720	28,390	20,710	15,360	11,130	8,700
50	54,130	42,100	33,310	25,040	18,420	13,780	10,080	–
55	47,880	38,620	29,770	22,540	16,710	12,600	–	–
60	44,320	34,890	27,050	20,610	15,390	11,230	–	–
65	40,400	31,950	24,900	19,090	14,350	10,560	–	–
70	32,240	29,590	23,180	17,870	13,520	9,650	–	–
75	35,600	27,660	21,770	16,340	12,420	–	–	–
80	32,530	26,060	20,610	15,560	11,500	–	–	–
85	30,740	24,720	19,080	14,450	10,720	–	–	–
90	29,230	22,970	17,780	13,930	10,060	–	–	–
95	27,860	21,980	16,610	13,060	–	–	–	–
100	26,040	20,600	16,060	12,310	–	–	–	–
105	25,180	19,490	15,230	11,700	–	–	–	–
Western Red Cedar	–							
25	–	–	57,750	43,360	33,400	24,000	17,700	13,270
30	–	–	47,430	36,190	27,080	19,810	14,110	11,420
35	65,820	52,450	39,780	30,720	23,300	16,560	11,970	9,820
40	57,540	44,870	34,420	26,880	19,860	14,310	10,490	8,270
45	51,090	40,210	31,160	23,730	17,710	12,920	9,590	7,300
50	45,190	35,790	27,940	21,460	16,170	11,470	8,580	–
55	40,780	32,500	25,550	19,770	14,520	10,790	–	–
60	37,400	29,980	23,720	17,920	13,250	9,920	–	–
65	34,750	28,010	21,660	16,460	12,260	9,240	–	–
70	32,640	25,750	20,020	15,290	11,460	8,400	–	–
75	30,190	23,910	18,670	14,340	10,810	–	–	–
80	28,840	22,400	17,560	13,560	9,970	–	–	–
85	27,090	21,120	16,640	12,540	9,540	–	–	–
90	25,600	20,050	15,850	12,010	8,920	–	–	–
95	24,300	19,100	14,780	11,240	–	–	–	–
100	22,670	18,300	14,220	10,860	–	–	–	–
105	21,790	17,230	13,420	10,280	–	–	–	–

[1] To obtain allowable loads for other safety factors, multiply the allowable loads shown above by 1.33 for SF = 3.0, 1.5 for SF = 2.67, or 2 for SF = 2.0.

Vertical Strength Requirements for Poles and Stubs (continued)

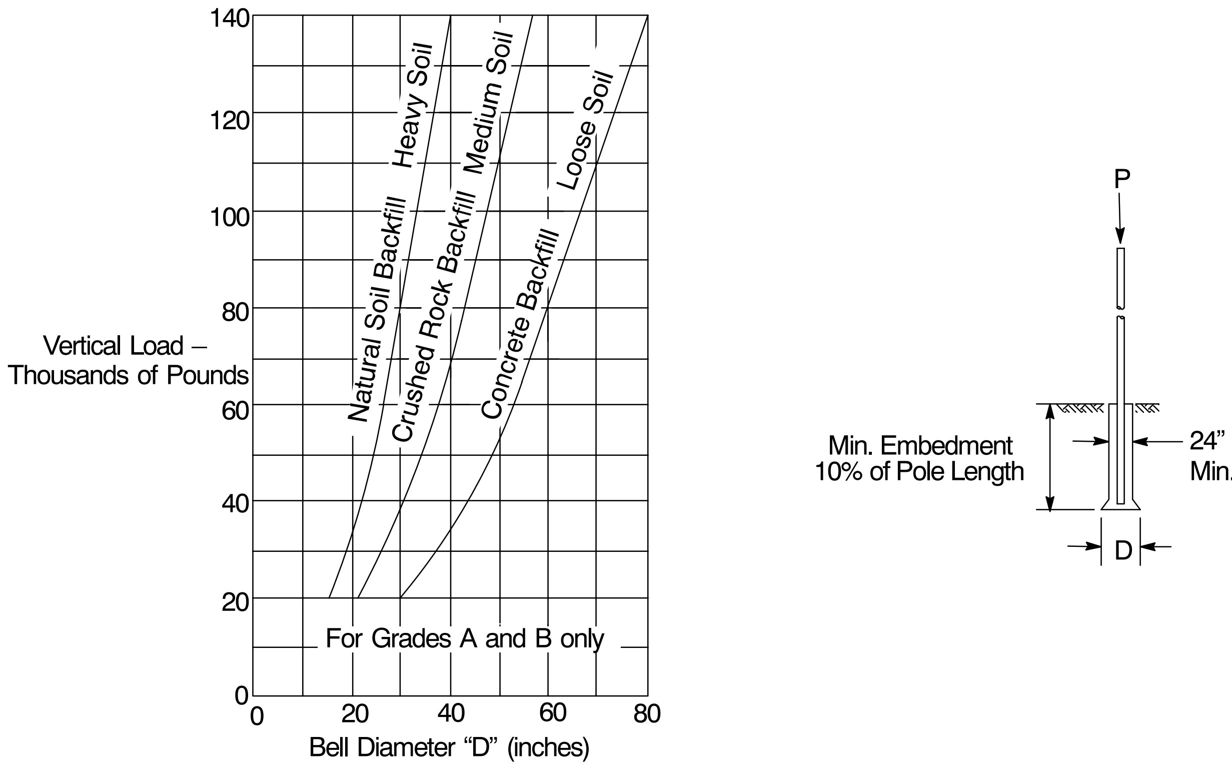


Figure 2
Embedment for Large Vertical Loads

Strength Requirements for Poles and Stubs Supporting Sidewalk Guys

Notes

1. The class of pole or stub that may be supported by a sidewalk guy is dependent only on the length of the pole and on the total horizontal tension on the pole when conductors are stressed to their maximum working loads.
2. The minimum class of pole or stub required when supporting a sidewalk guy may be determined as follows:
   A. At each conductor level, obtain the maximum horizontal conductor tension on the pole due to dead-end or angle construction for which the pole is being guyed.
   B. Using the total horizontal conductor tension on the pole, determine the minimum class of pole required from Table 12 on Pages 16 and 17, based on pole height and grade of construction.
3. The following example illustrates the use of Table 12 for sidewalk guy installations.

   Given:

   A. 35° line angle on 45-foot pole.
   B. 2 #4 ACSR 4 kV primary, short span urban.
   C. 3 #1/0 all-aluminum secondary.
   D. “Grade B” construction.

   Total Horizontal Tension on Pole at Maximum Conductor Loading

   From Chart 2, Document 022178:

   1. 2 #4 ACSR at 35° angle, tension = 270 pounds x 2 = 540 pounds
   2. 3 #1/0 all-aluminum, 35° angle, tension = 410 pounds x 3 = 1,230 pounds

   Total = 1,770 pounds

   Determination of Minimum Pole Class Required

   From Table 12 on Page 16, for 1,770 pounds tension in “Grade B” construction, a Class 5 pole is required for a 45-foot pole.

Table 12 Class of Pole Required for Sidewalk Guy [1]

Total Horizontal Tension on Pole (pounds)			Length of Pole (feet)										
“Grade A”	“Grade B”	“Grade C”	25	30	35	40	45	50	55	60	65	70	75
500	667	1,000	6	6	6	6	6	5	4	3	3	3	3
600	800	1,200	5	6	6	6	6	5	4	3	3	3	3
700	933	1,400	5	6	6	6	6	5	4	3	3	3	3
800	1,067	1,600	4	5	6	6	6	5	4	3	3	3	3
900	1,200	1,800	4	5	6	6	6	5	4	3	3	3	3
1,000	1,333	2,000	3	4	5	6	6	5	4	3	3	3	3
1,100	1,467	2,200	3	4	5	5	6	5	4	3	3	3	3
1,200	1,600	2,400	3	4	4	5	6	5	4	3	3	3	3
1,300	1,733	2,600	2	3	4	5	5	5	4	3	3	3	3
1,400	1,867 [2]	2,800	2	3	4	4	5 [2]	5	4	3	3	3	3
1,500	2,000	3,000	2	3	3	4	5	5	4	3	3	3	3
1,600	2,133	3,200	1	2	3	4	5	5	4	3	3	3	3
1,700	2,267	3,400	1	2	3	4	4	5	4	3	3	3	3
1,800	2,400	3,600	1	2	3	3	4	5	4	3	3	3	3
1,900	2,533	3,800	1	2	3	3	4	4	4	3	3	3	3
2,000	2,667	4,000	–	1	2	3	4	4	4	3	3	3	3

[1] For a safety factor of 2.67, use the figures in the “Grade A” column multiplied by 1.5.
[2] Figures are used in the example (Note 3 on Page 16).

Strength Requirements for Poles and Stubs Supporting Sidewalk Guys (continued)

Table 12 Class of Pole Required for Sidewalk Guy (continued)

Total Horizontal Tension on Pole (pounds)			Length of Pole (feet)										
“Grade A”	“Grade B”	“Grade C”	25	30	35	40	45	50	55	60	65	70	75
2,100	2,800	4,200	–	1	2	3	3	4	4	3	3	3	3
2,200	2,933	4,400	–	1	2	3	3	4	4	3	3	3	3
2,300	3,067	4,600	–	1	2	2	3	3	4	3	3	3	3
2,400	3,200	4,800	–	1	2	2	3	3	4	3	3	3	3
2,500	3,333	5,000	–	–	1	2	3	3	4	3	3	3	3
2,600	3,467	5,200	–	–	1	2	3	3	4	3	3	3	3
2,700	3,600	5,400	–	–	1	2	2	3	3	3	3	3	3
2,800	3,733	5,600	–	–	1	2	2	3	3	3	3	3	3
2,900	3,867	5,800	–	–	1	1	2	3	3	3	3	3	3
3,000	4,000	6,000	–	–	–	1	2	3	3	3	3	3	3
3,100	4,133	6,200	–	–	–	1	2	2	3	3	3	3	3
3,200	4,267	6,400	–	–	–	1	2	2	3	3	3	3	3
3,300	4,400	6,600	–	–	–	1	1	2	3	3	3	3	3
3,400	4,533	6,800	–	–	–	1	1	2	2	3	3	3	3
3,500	4,667	7,000	–	–	–	H1	1	2	2	3	3	3	3
3,600	4,800	7,200	–	–	–	H1	1	2	2	3	3	3	3
3,700	4,933	7,400	–	–	–	H1	1	2	2	2	3	3	3
3,800	5,067	7,600	–	–	–	H1	1	1	2	2	3	3	3
3,900	5,200	7,800	–	–	–	H1	1	1	2	2	3	3	3
4,000	5,333	8,000	–	–	–	H1	1	1	2	2	3	3	3
4,100	5,467	8,200	–	–	–	H1	H1	1	2	2	2	3	3
4,200	5,600	8,400	–	–	–	H1	H1	1	2	2	2	3	3
4,300	5,733	8,600	–	–	–	H2	H1	1	1	2	2	3	3
4,400	5,866	8,800	–	–	–	H2	H1	1	1	2	2	3	3
4,500	6,000	9,000	–	–	–	H2	H1	1	1	2	2	2	3
4,600	6,133	9,200	–	–	–	H2	H1	H1	1	2	2	2	3
4,700	6,267	9,400	–	–	–	H2	H1	H1	1	1	2	2	3
4,800	6,400	9,600	–	–	–	H2	H1	H1	1	1	2	2	3
4,900	6,533	9,800	–	–	–	H2	H1	H1	1	1	2	2	2
5,000	6,667	10,000	–	–	–	H2	H2	H1	1	1	2	2	2
5,100	6,800	10,200	–	–	–	H2	H2	H1	1	1	1	2	2
5,200	6,933	10,400	–	–	–	–	H2	H1	H1	1	1	2	2
5,300	7,067	10,600	–	–	–	–	H2	H1	H1	1	1	2	2
5,400	7,200	10,800	–	–	–	–	H2	H1	H1	1	1	2	2
5,500	7,333	11,000	–	–	–	–	H2	H1	H1	1	1	2	2
5,600	7,467	11,200	–	–	–	–	H2	H2	H1	1	1	1	2
5,700	7,600	11,400	–	–	–	–	H2	H2	H1	1	1	1	2
5,800	7,733	11,600	–	–	–	–	H2	H2	H1	1	1	1	2
5,900	7,867	11,800	–	–	–	–	H2	H2	H1	H1	1	1	2
6,000	8,000	12,000	–	–	–	–	–	H2	H1	H1	1	1	2

Revision Notes

Revision 05 has the following changes:

1. Expanded “Page” reference in Footnote 1 of Table 3 on Page 7 and Table 7 and Table 8 on Page 10.
2. Added Footnote 1 to Table 9 on Page 10 referencing the use of the Equipment Moment Multiplier.
3. Expanded Notes 9 and 10 on Page 11 to give more guidance on sizing certain guyed poles.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Public Service Electric & Gas

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.

JULY 21, 2020

AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Public Service Electric & Gas

1. Overhead mounted transformers on wooden utility poles

a. **How many man-hours does the typical new transformer installation consume?**
4 man-hours

b. **Does the transformer's weight (lbs.) play a factor?**
No

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**
No

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Secondary bus conductor size, NEMA pad connector

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
Not readily available
- **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
Not readily available
- **What alternative options would be considered to avoid upgrading the electrical pole?**
Choose a different structure nearby, guying, trussing the pole

2. Surface (pad) mounted transformers

a. **How many man-hours does the typical new transformer installation consume?**
6 mhrs (2 hours x 3 man crew)

b. **Does the transformer's weight (lbs.) play a factor?**
Yes

- **If yes, under what circumstances?**
Heavier transformers require a crane to set

- **How often do these circumstances occur?**
  20%

c. **Does the transformer's volume play a factor?**
   No
   - **If yes, under what circumstances?**
   - **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
   None

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**
   - **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad?**
     Would not occur unless existing transformer kVA was being increased. Per construction handbook, several pad sizes available based on size of transformer. Transformer purchase specifications include max dimensions which are strictly enforced
   - **What alternative options would be considered to avoid replacement of the supporting pad?**
     xx

3. Underground vault (installed below grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
   <u>Spot Network</u>: To just set the transformers (typical installation is a three transformer spot network) would be one day (6 work hours x 3 man crew = 18 manhours). Energizing may take longer due to switching and circuit outage availability. For the entire installation, it takes about ten working days (6 hours/day x 10 days x 3 man crew = 180 manhours) to complete all transformer work including primary and secondary cables.
   <u>Street or Grid Network:</u> To just set the transformer (typical installation is one transformer per equipment manhole) would be a half day (4 work hours x 3 man crew = 12 manhours). Energizing may take longer due to switching and circuit outage availability. For the entire installation, it takes about three working days to complete all transformer work including primary and secondary cables.

b. **Does the transformer's weight (lbs.) play a factor?**
   No
   - **If yes, under what circumstances?**
   - **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**
   Yes

- **If yes, under what circumstances?**
  Width is critical dimension in UG submersible units due to frame opening.
- **How often do these circumstances occur?**
  2%. Replacement of smaller older units can be an issue. Company transformer purchase specifications limit new transformer dimensions, and this in strictly enforced

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?
Secondary conductors

e. For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**
  Width exceeding 48" for smaller kVA, and width exceeding 64" on larger kVA
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**
  Install new frame on manhole

4. Underground subsurface (installed at grade) installed transformers

a. How many man-hours does the typical new transformer installation consume?
To just set the transformer (typical installation is one transformer per equipment manhole) would be a half day (4 work hours x 3 man crew = 12 manhours). Energizing may take longer due to switching and circuit outage availability. For the entire installation, it takes about three working days to complete all transformer work including primary and secondary cables. days (6 hours/day x 3 days x 3 man crew = 54 manhours.) Note: PSE&G does very little of this type of installation. Most of our system is submersible below grade installations.

b. Does the transformer's weight (lbs.) play a factor?
No

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

c. Does the transformer's volume play a factor?
Yes

- **If yes, under what circumstances?**
  Width is critical dimension in UG submersible units due to frame opening
- **How often do these circumstances occur?**
  2%. Replacement of smaller older units can be an issue. Company transformer purchase specifications limit new transformer dimensions, and this in strictly enforced

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?
Number of secondary cables

e. For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure?**
  Varies by transformer type and size
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**
  Custom solution based on each job and circumstances.

Summary

Overhead Transformers:

- Transformer install ≈ 4 man-hours

Pad-mounted Transformers:

- Transformer install ≈ 6 man-hours
- Maximum size limitations are strictly enforced

Underground (Vault) Transformers

- Spot Network: New transformer install ≈ 180 man-hours complete, 18 man-hours transformer only
- Grid Network: Transformer install ≈ 180 man-hours
- Transformer width is critical limit

Underground Subsurface Transformers

- New transformer install ≈ 54 man-hours complete, 12 man-hours transformer only
- Transformer width is critical limit

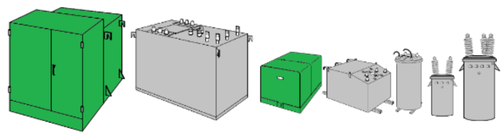
Note:

PSE&G only considers 6 hours/man-day to be available for work.

Contact:

David S. Blew
Manager – Outside Plant
PSE&G
80 Park Plaza, T17
Newark, NJ 07102
973-430-7743 office
973-220-1663 cell

MULKEY ENGINEERING INC.



CONTACT: DAN MULKEY
707-776-7346
MULKEYENGINEERING@YAHOO.COM

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Moon Lake Electric Association

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.

JULY 21, 2020

AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Moon Lake Electric Association

1. Overhead mounted transformers on wooden utility poles

a. **How many man-hours does the typical new transformer installation consume?**
   2 man-hours

b. **Does the transformer's weight (lbs.) play a factor?**
   Yes

   - **If yes, under what circumstances?**
     If the transformer is 37.5 or smaller it can be hung using a small bucket truck with a jib, no need for a digger truck.
   - **How often do these circumstances occur?**
     Less than 25% of the time

c. **Does the transformer's volume play a factor?**
   Not usually

   - **If yes, under what circumstances?**
   - **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
   No change in material unless it is a conventional transformer then a combination cutout is used.

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

   - **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
     Typically, we use class 4 poles for single phase lines and class 3 for three-phase. On smaller size transformers we would use the class 4 poles. If they get bigger than 25 KVA then we would look at upgrading the pole. On large three-phase services we would install a class 2 pole or possibly a class 1.
   - **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
     We utilize a third party software to analyze our poles.
   - **What alternative options would be considered to avoid upgrading the electrical pole?**
     If the analysis software indicates the pole is overloaded, it would have to be changed.

2. Surface (pad) mounted transformers

a. **How many man-hours does the typical new transformer installation consume?**
   3 man-hours

b. **Does the transformer's weight (lbs.) play a factor?**

Yes

- **If yes, under what circumstances?**
  The distance to the pad, if one has to reach far then the load limit can be an inhibiting factor.
- **How often do these circumstances occur?**
  Not often in new construction because there usually isn't anything keeping us from getting close to the pad. If we have to change a transformer that has been installed for a while, the landscaping and construction (buildings, retaining walls etc.) around the transformer can make the distance great enough that a crane or bigger digger must be used.

c. **Does the transformer's volume play a factor?**

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Size of pad possibly, size of conductor.

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad?**
  6 inches in width
- **What alternative options would be considered to avoid replacement of the supporting pad?**
  On a cement pad I have seen the pad extended by pouring more cement. Fiber glass pads would have to be changed out to bigger pad.

3. Underground vault (installed below grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
N/A - Moon Lake Electric Association does not use this installation type.

b. **Does the transformer's weight (lbs.) play a factor?**

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**

- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**

4. Underground subsurface (installed at grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
N/A - Moon Lake Electric Association does not use this installation type.

b. **Does the transformer's weight (lbs.) play a factor?**

- **If yes, under what circumstances?**

- **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**

- **If yes, under what circumstances?**

- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure?**

- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**

Summary

Overhead Transformers:

- Transformer install ≈ 2 man-hours
- Install Class 4 poles for 1Ph, Class 3 for 3Ph
- Transformer > 25 kVA might upgrade pole
- 37.5 kVA or under use small bucket truck

Pad-mounted Transformers:

- Transformer install ≈ 3 man-hours
- Present design is within 6" of maximum width

Underground (Vault) Transformers

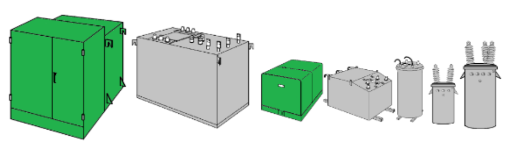
- N/A

Underground Subsurface Transformers

- N/A

Contact:

Curtis Miles
Line Superintendent
Moon Lake Electric Association
O (435) 722-5412
C (435) 823-7506
cmiles@mleainc.com

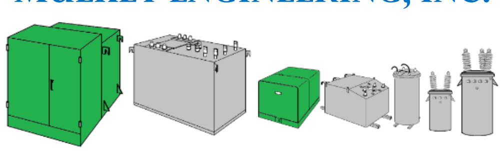


LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

A Colorado Rural Electric Cooperative

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.



JULY 21, 2020

AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

A Colorado Rural Electric Cooperative

1. Overhead mounted transformers on wooden utility poles

a. **How many man-hours does the typical new transformer installation consume?**
   3 hours cold – 4.5 hours hot
   [cold = primary conductors are de-energized, hot = primary is energized]

b. **Does the transformer's weight (lbs.) play a factor?**
   Yes
   - **If yes, under what circumstances?**
     Larger kVA size would be installed on larger class pole
   - **How often do these circumstances occur?**
     10% of the time

c. **Does the transformer's volume play a factor?**
   No
   - **If yes, under what circumstances?**
   - **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
   Larger class of pole & larger bolts

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**
   - **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
     Not available
   - **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
     Not available
   - **What alternative options would be considered to avoid upgrading the electrical pole?**
     Riser and pad mount transformer

2. Surface (pad) mounted transformers

a. **How many man-hours does the typical new transformer installation consume?**
   6 hours

b. **Does the transformer's weight (lbs.) play a factor?**
   No
   - **If yes, under what circumstances?**
     N/A

- **How often do these circumstances occur?**
  N/A

c. **Does the transformer's volume play a factor?**
   No

   - **If yes, under what circumstances?**
     N/A
   - **How often do these circumstances occur?**
     N/A

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
   Secondary connector pads

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**
   - **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad?**
     Not available
   - **What alternative options would be considered to avoid replacement of the supporting pad?**
     None

3. Underground vault (installed below grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
   N/A This type is not used.

b. **Does the transformer's weight (lbs.) play a factor?**

   - **If yes, under what circumstances?**
   - **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**

   - **If yes, under what circumstances?**
   - **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**
   - **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**

- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**

4. Underground subsurface (installed at grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
N/A This type is not used

b. **Does the transformer's weight (lbs.) play a factor?**

- **If yes, under what circumstances?**

- **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**

- **If yes, under what circumstances?**

- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure?**

- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**

Summary

Overhead Transformers:

- Transformer install ≈ 3 hours cold, 4.5 hours hot
- Install larger class poles for larger transformers

Pad-mounted Transformers:

- Transformer install ≈ 6 hours

Underground (Vault) Transformers

- N/A

Underground Subsurface Transformers

- N/A

Contact:

Anonymous

Respondent's Request:

We also request that xxxxx name not be specifically attached to this questionnaire. We are fine if you want to label it as a Colorado Rural Electric Cooperative.

MULKEY ENGINEERING INC.

CONTACT: DAN MULKEY
707-776-7346
MULKEYENGINEERING@YAHOO.COM

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Knoxville Utilities Board

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.

JULY 21, 2020
AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Knoxville Utilities Board

1. Overhead mounted transformers on wooden utility poles

a. How many man-hours does the typical new transformer installation consume?

Depends on number, single unit or banked. Here are a few typical values:

- 1 single-phase unit ≈ 5 man-hours
- 3 banked single-phase units ≈ 14 man-hours

Also, to be clear, KUB has generally leaned towards using steel, concrete or ductile iron poles for 3-phase banked transformer installations in lieu of wooden poles.

b. Does the transformer's weight (lbs.) play a factor?

In what (time to install, line design (pole sizing), etc.? If specifically considering installation time, not typically. Transformers are generally of a consistent weight by capacity for our system historically. KUB specifies a Stock transformer weight limit. This limit is based primarily on the design restrictions of our stock cluster mounting hardware for 3-phase banks with additional input from other stakeholders on equipment handling considerations. Even the use of heavier amorphous core materials for OH units has not to date been an issue because we have planned for them. From our specification…x

3.03 The core steel shall be of the highest quality grain oriented, low loss, burr-free, low induction level, and high permeability silicon steel. Alternate core material of low loss amorphous metal is acceptable provided that the transformer weights do not get excessive.

11.14 The total mass of the transformer including bushings, terminals, accessories and oil shall not exceed 1,625 pounds.

- **If yes, under what circumstances?**
  N/A
- **How often do these circumstances occur?**
  In nearly 30 years of utility service, I am not aware of any circumstance where transformer weight became and installation issue.

c. Does the transformer's volume play a factor?

Not that I am aware of. Unlike, pad-mounted and power transformers, the fluid volumes are typically very small and do not begin to approach EPA regulatory concerns relative to SPCC or other planning. I suppose that volume might require consideration for fire protection concerns, but NESC clearances and our design guidelines likely address these issues.

- **If yes, under what circumstances?**
  N/A
- **How often do these circumstances occur?**
  Never

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
None that I can think of at this time. Simplistically, I suppose the larger the capacity, the more energy/fuel is spent to deliver the unit to its destination, as well as, putting it into service.

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
Great question. Our Standards Team is currently developing a design guideline to address this for new employees and less seasoned design technicians/Engineers. As of now, experience is what dictates these design considerations.
- **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
I am uncertain, but expect that this is also considered in our designs with the use of PLS-CADD
- **What alternative options would be considered to avoid upgrading the electrical pole?**
None that I am aware of.

2. Surface (pad) mounted transformers

a. **How many man-hours does the typical new transformer installation consume?**
Like OH transformer considerations, this depends on whether the unit is a single or three-phase unit. Here are a few typical values:

- 1 single-phase unit ≈ 11 man-hours
- 1 three-phase unit ≈ 25 man-hours

Generally, single-phase pads are consistently small, dimensionally and by weight, while three-phase units are considerably larger, especially above 750 kVA which may have an abundance of cooling fins affecting their overall site footprint.

b. **Does the transformer's weight (lbs.) play a factor?**
Yes, particularly if one considers the installation equipment required to deliver and off-load various transformer types and capacities.

- **If yes, under what circumstances?**
Smaller single-phase transformers are relatively light. They can be delivered to a job site with fewer/smaller equipment requirements, and they are easily set within our routine design constraints.
Larger three-phase transformers are considerably heavier. They require additional, often much larger, equipment to deliver them to the job site. An extra flatbed truck or trailer is often needed. Also, off-loading them may require something more than a line truck to place them on their foundations, particularly legacy locations which may be hard to reach or gain access too. Sometimes, if the transformer is large and distant from off-loading equipment access, a crane may be necessary to safely install such transformers.

- **How often do these circumstances occur?**
  Each job is different and requires advance planning for safe/successful installation. Weight considerations are rarely extraordinary, but crane off-loading for 3-phase units is not unheard of.

c. Does the transformer's volume play a factor?

Not routinely, although we have begun to see some new customer service requirements that require SPCC planning/design considerations.
Again, these transformers need consideration for fire protection so guidelines for clearances to buildings need to be addressed.
I am not aware of any other single unit service concerns for fluid volume… which even for our largest 3000 kVA pad-mounted units is generally less than 1000 gallons. Our specifications, take care of this limit.

10.07 The transformer oil volume shall not exceed one thousand two hundred (1200) gallons.

- **If yes, under what circumstances?**
  Multi-unit 3-phase pad-mounted transformer services having in excess of 1,320 gallons of fluid require us to have an SPCC Plan and/or design to address fluid levels exceeding EPA regulatory limits.
- **How often do these circumstances occur?**
  Infrequently. However, we have seen the first of three such installations on our system within the last two years.

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?

Again, none that I can think about at the time. Simplistically, I suppose the larger the capacity, the more energy/fuel is spent to deliver the unit to its destination, as well as, putting it into service. Additionally, cable preparation is different for three-phase units so material needs increase accordingly with added connections.

e. For each: single single-phase transformer, single three-phase transformer, and ~~bank of three single-phase transformers~~ what is:

- **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad?**
  Single-phase transformer base is required to fit on a standardized Highline Products HL-45 fiberglass box pad. Three-phase transformer base is specified to fit on a standardized 8’ x 8’ concrete pad. Cooling fins may overhang the pad. Both with appropriate clearances to accommodate installation, maintenance, protection, cooling, and replacement needs.

  1Ph: Max 37.5” W, 43” D; Actual 36” W, 41.2” D; so 1.5” x 1.8” available, or 8% available footprint
  3Ph: Max 96” W, 96” D; Actual 75.5” W, 78.5” D; so 20.5” x 17.5” available, or 36% available footprint

  [No height restriction.]

- **What alternative options would be considered to avoid replacement of the supporting pad?**
  We have been known to pour foundation additions around existing legacy transformers to accommodate a replacement unit. Sometimes, an entirely new service is needed, but this would be extremely rare.

3. Underground vault (installed below grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
Really difficult to get a "typical" for this. Too many variables: safety concerns, time-of-day, public access, traffic concerns/controls, vault accessibility, to name only a few.
I spoke with one of our downtown network engineers who suggested using a 12-man crew for 12 hours, or 144 man-hours.

b. **Does the transformer's weight (lbs.) play a factor?**
Yes

- **If yes, under what circumstances?**
  Depending on the accessibility, the installation may require a crane or such. We have often used Heavy-Duty towing/wrecker vehicles to navigate the tight spaces and clearances necessary to get equipment into service on our downtown network system.
- **How often do these circumstances occur?**
  Infrequently. Very few new customers are being added to our downtown network area, plus we did a major upgrade/overhaul about ten years ago, so our transformer/equipment replacement work is minimal.

c. **Does the transformer's volume play a factor?**
Not to my knowledge.

- **If yes, under what circumstances?**
  N/A
- **How often do these circumstances occur?**
  N/A

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
None to my knowledge. Most such installations are very similar in design and material needs.

e. **For each: single single-phase transformer, single three-phase transformer, and ~~bank of three single-phase transformers~~ what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**
  Transformers and vault sizes/access requirements are sized to future maintenance and replacement needs… accommodating allowances for our largest units for potential upgrades.
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**
  See above.

4. Underground subsurface (installed at grade) installed transformers

a. How many man-hours does the typical new transformer installation consume?
KUB does not utilize these types of transformers/services on our electric system.

b. Does the transformer's weight (lbs.) play a factor?
N/A

- **If yes, under what circumstances?**
  N/A
- **How often do these circumstances occur?**
  N/A

c. Does the transformer's volume play a factor?
N/A

- **If yes, under what circumstances?**
  N/A
- **How often do these circumstances occur?**
  N/A

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?
N/A

e. For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:
N/A

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure?**
  N/A
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**
  N/A

Summary

Overhead Transformers:

- Transformer install ≈ 5 man-hours single-phase, 14 man-hours three-phase
- Specify max weight of 1625 lbs.

Pad-mounted Transformers:

- Transformer install ≈ 11 man-hours single-phase, 25 man-hours three-phase Present design is
- Weight issue on three-phase
- 1Ph: Within 8% of available footprint
- 3Ph: Within 36% of available footprint

Underground (Vault) Transformers

- Transformer install ≈ 144 man-hours

Underground Subsurface Transformers

- N/A

Contact:

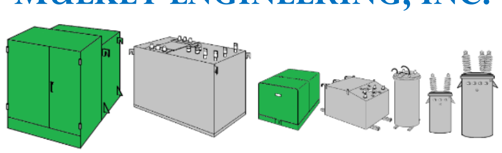
Bruce Webb, PE
KUB Engineering
4505 Middlebrook Pike
Knoxville, TN 37921
(865) 558-2762 Office
(865) 546-9322 Mobile
bruce.webb@kub.org

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Fort Collins Utilities

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.



JULY 21, 2020

AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Fort Collins Utilities

1. Overhead mounted transformers on wooden utility poles

a. How many man-hours does the typical new transformer installation consume?
N/A – Fort Collins Utilities only installs underground. When acquiring facilities with overhead they convert them to underground

b. Does the transformer's weight (lbs.) play a factor?

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

c. Does the transformer's volume play a factor?

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?

e. For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:

- **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
- **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
- **What alternative options would be considered to avoid upgrading the electrical pole?**

2. Surface (pad) mounted transformers

a. How many man-hours does the typical new transformer installation consume?
Transformer and services:
Single-phase: 16 (4-man for 4-hours)
Three-phase: 29.5 (4-men for 7 hours plus 1.5 hours for equipment specialist)

b. Does the transformer's weight (lbs.) play a factor?

Occasionally

- **If yes, under what circumstances?**
  When installing in an alcove with less than 30 ft. clearance, the weight impacts equipment needs
- **How often do these circumstances occur?**
  Less than 2 times per year

c. Does the transformer's volume play a factor?

Yes

- **If yes, under what circumstances?**
  Volume affects oil spill containment requirements
- **How often do these circumstances occur?**
  Always

d. What materials are consumed during the installation process that change as the kVA of the transformer increases?

Fuse size

Secondary cable size

Two different sized pads for three-phase pad-mounts

e. For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:

- **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad?**
  1-phase: Allowed 37” w x 43” d x 34” h vs Actual 34” x 41.25” x 34”; so Available: 2” x 1.75” x 0” or 12% of volume; 12 % of footprint
  3-phase: Allowed 100” w x 80” d vs Actual 70” x 63.2” so Available: 30” x 16.8” or 45% of footprint
- **What alternative options would be considered to avoid replacement of the supporting pad?**
  Pouring an extra strip of concrete to accommodate transformer overhang
  Create a new larger standard pad which has consequences for replacements

3. Underground vault (installed below grade) installed transformers

a. How many man-hours does the typical new transformer installation consume?

N/A – only have a couple of installations

b. Does the transformer's weight (lbs.) play a factor?

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

c. Does the transformer's volume play a factor?

- **If yes, under what circumstances?**

- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**

- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**

4. Underground subsurface (installed at grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
Single-Phase: 13.8 (4-men for 3.2 hours plus 1 hour for equipment specialist)
Three-Phase: N/A – only have two installations

b. **Does the transformer's weight (lbs.) play a factor?**
No

- **If yes, under what circumstances?**

- **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**
Yes

- **If yes, under what circumstances?**
  Transformer must fit into 3'x6'x54" enclosure
- **How often do these circumstances occur?**
  Always

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Secondary/service cables increase with transformer kVA

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure?**
  Single-phase: "spot on to maximum dimensions"

Three-phase: Allowed 54” w x 76” d x 78” h vs Actual 53.12” x 72.5” x 74.87” so Available: 0.88” x 3.5” x 3.13” or 10% by volume

- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**
  Would have to use larger enclosure size, e.g. 4’x8’, and new larger allowed maximum dimensions. This is very problematic as it makes existing installations obsolete requiring new enclosures for transformer replacements instead of just straight forward transformer replacement. This also would affect the placement of the other utilities in the joint trench within the public utility easement and possibly require additional right-of-way

Notes:

Fort Collins uses a submersible horizontal transformer similar to the style used by PG&E. They install 25 kVA or 50 kVA transformers and hold the 75 kVA size in reserve for load growth.

Summary

Overhead Transformers:

- N/A

Pad-mounted Transformers:

- Transformer install ≈ 16 man-hours single-phase, 29.5 man-hours three-phase
- 1Ph: Within 8% of available footprint
- 3Ph: Within 36% of available footprint
-

Underground (Vault) Transformers

- N/A

Underground Subsurface Transformers

- Transformer install ≈ 13.8 man-hours
- Present design is within 10% of available volume

Contact:

JIM SPAULDING
Standards Engineering Lead
City of Fort Collins – Light & Power
700 Wood St.
Ft. Collins CO 80521
jspaulding@fcgov.com
970-416-4231

MULKEY ENGINEERING INC.

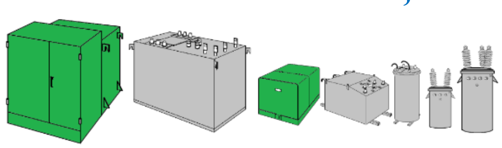
CONTACT: DAN MULKEY
707-776-7346
MULKEYENGINEERING@YAHOO.COM

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Braintree Electric Light Department

COMMISSIONED BY
LAWRENCE BERKELEY NATIONAL LABORATORY

MULKEY ENGINEERING, INC.



JULY 21, 2020

AUTHORED BY: DAN MULKEY, P.E.

LIMITATIONS ON DISTRIBUTION TRANSFORMER INSTALLATIONS

Braintree Electric Light Department

1. Overhead mounted transformers on wooden utility poles

a. **How many man-hours does the typical new transformer installation consume?**
16 man-hours (two 2-man crews for 4 hours)

b. **Does the transformer's weight (lbs.) play a factor?**
Yes

- **If yes, under what circumstances?**
During the procurement process, prefer to select the lighter units that meet all technical requirements (for ease of installation)
- **How often do these circumstances occur?**
Not often (BELD's standard practice is to install 25 or 50 kVA overhead units)

c. **Does the transformer's volume play a factor?**
Not really because of BELD's standard practice of using standard 25 and 50 kVA units

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Fused cutout

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **the maximum static load (in lbs.) for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
BELD's standard practice is to use Class 2, 40-foot poles; with standard 25 or 50 kVA overhead transformers, so there is not any concern about load/pole requirements
- **the maximum offset-bending load for each grade of wooden electrical pole which, if surpassed would require the pole to be upgraded.**
See above
- **What alternative options would be considered to avoid upgrading the electrical pole?**
N/A

2. Surface (pad) mounted transformers

a. **How many man-hours does the typical new transformer installation consume?**
24 man-hours (three 2-man crews for 4 hours)

b. **Does the transformer's weight (lbs.) play a factor?**
Yes

- **If yes, under what circumstances?**
  It affects whether BELD's regular digger truck can be used to load/offload the transformer, or an outside rigging service would be required.
- **How often do these circumstances occur?**
  BELD handles installation/rigging most of the time (>95%).

c. **Does the transformer's volume play a factor?**
Yes

- **If yes, under what circumstances?**
  Weight and possible need for oil containment (depending on installation location, nature of business, environmental consideration, etc.)
- **How often do these circumstances occur?**
  Not often at all

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Fuses, phase/neutral conductors

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would require the replacement of the supporting pad?**
  Single-phase: Allowed 48" w x 48" d vs. Actual 36" x 40" so Available: ~38% of footprint
  Three-phase: Allowed 96" w x 96" d vs. Actual 73" x 60" so Available: ~52% of footprint
  [No height restriction]
- **What alternative options would be considered to avoid replacement of the supporting pad?**
  N/A

3. Underground vault (installed below grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
36 (three 2-man crews for 6 hours)

b. **Does the transformer's weight (lbs.) play a factor?**
Yes

- **If yes, under what circumstances?**
  BELD's only vault-type transformers are in the tunnel of a large shopping mall; installation/replacement of these vault-type transformers would require outside assistance with rigging.
- **How often do these circumstances occur?**
  A couple of times a year in scheduled outages

c. **Does the transformer's volume play a factor?**
Yes

- **If yes, under what circumstances?**
  Available space at installation location and oil containment consideration

- **How often do these circumstances occur?**
  Not often at all

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**
Upstream protective device (power fuses or vacuum interrupter), phase/neutral conductors, surge arresters, oil containment (if applicable), ventilation, etc.

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing underground vaults?**
  All vault-type transformer replacements at BELD have been like-for-like replacements that required no or very little modifications to the electrical vaults.
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing underground vault?**
  N/A

4. Underground subsurface (installed at grade) installed transformers

a. **How many man-hours does the typical new transformer installation consume?**
N/A BELD does not have any subsurface transformers.

b. **Does the transformer's weight (lbs.) play a factor?**

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

c. **Does the transformer's volume play a factor?**

- **If yes, under what circumstances?**
- **How often do these circumstances occur?**

d. **What materials are consumed during the installation process that change as the kVA of the transformer increases?**

e. **For each: single single-phase transformer, single three-phase transformer, and bank of three single-phase transformers what is:**

- **What is the maximum increase in either transformer width, length, or height that would prohibit the installation in existing enclosure?**
- **What action would be taken if the only available transformer has dimensions that prohibit its installation into the existing enclosure?**

Summary

Overhead Transformers:

- Transformer install ≈ 16 man-hours
- Typically use only 25 and 50 kVA units on Class 2, 40 foot poles

Pad-mounted Transformers:

- Transformer install ≈ 24 man-hours
- 1Ph: Within 38% of available footprint
- 3Ph: Within 52% of available footprint

Underground (Vault) Transformers

- Transformer install ≈ 36 man-hours

Underground Subsurface Transformers

- N/A

Contact:

Weijun Li, P.E.
Engineering & Operations Manager
Braintree Electric Light Department
150 Potter Road, Braintree, MA 02184
781.348.1076 | M: 617.212.4784
wli@beld.com

APPENDIX 8E. DISTRIBUTIONS USED FOR DISCOUNT RATES

TABLE OF CONTENTS

LIST OF TABLES

APPENDIX E. DISTRIBUTIONS USED FOR DISCOUNT RATES

8E.1 DISTRIBUTIONS USED FOR COMMERCIAL/INDUSTRIAL DISCOUNT RATES

Table 8E.1.1 Education Sector Discount Rate Distribution

Bin	Bin Range	Rates	Weight (% of companies)	# of Companies
1	<0%			
2	≥0 to <1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%			
7	5-6%	5.42%	23.9%	174
8	6-7%	6.52%	39.4%	287
9	7-8%	7.34%	13.9%	101
10	8-9%	8.35%	22.8%	166
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.79%**		

Table 8E.1.2 Food Sales Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%	3.83%	8.0%	55
6	4-5%	4.79%	38.3%	264
7	5-6%	5.50%	29.6%	204
8	6-7%	6.37%	12.3%	85
9	7-8%	7.89%	2.3%	16
10	8-9%	8.77%	4.6%	32
11	9-10%	9.25%	2.6%	18
12	10-11%	10.23%	2.2%	15
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**5.61%**		

Table 8E.1.3 Food Service Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%			
7	5-6%	5.56%	38.8%	551
8	6-7%	6.60%	49.6%	704
9	7-8%	7.18%	11.6%	165
10	8-9%			
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.26%**		

Table 8E.1.4 Health Care Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%			
7	5-6%	5.51%	36.9%	1,781
8	6-7%	6.35%	28.8%	1,390
9	7-8%	7.38%	23.9%	1,153
10	8-9%	8.37%	10.3%	499
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.50%**		

Table 8E.1.5 **Lodging Sector Discount Rate Distribution**

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%	4.66%	26.1%	389
7	5-6%	5.36%	18.4%	274
8	6-7%	6.54%	34.7%	516
9	7-8%	7.27%	14.8%	220
10	8-9%	8.33%	6.0%	89
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.05%**		

Table 8E.1.6 **Mercantile Discount Rate Distribution**

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%	4.68%	1.0%	50
7	5-6%	5.56%	23.6%	1,189
8	6-7%	6.49%	36.9%	1,863
9	7-8%	7.45%	36.2%	1,825
10	8-9%	8.29%	2.4%	121
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.64%**		

Table 8E.1.7 **Office Sector Discount Rate Distribution**

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			

2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%	3.73%	7.6%	3,061
6	4-5%	4.57%	19.6%	7,913
7	5-6%	5.46%	22.5%	9,099
8	6-7%	6.39%	14.2%	5,711
9	7-8%	7.47%	8.4%	3,398
10	8-9%	8.56%	15.0%	6,066
11	9-10%	9.48%	5.8%	2,358
12	10-11%	10.40%	2.7%	1,094
13	11-12%	11.21%	1.3%	531
14	12-13%	12.45%	1.9%	786
15	≥13%	13.88%	0.8%	342
Weighted Average		**6.57%**		

Table 8E.1.8 Public Assembly Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%	4.86%	2.2%	73
7	5-6%	5.64%	11.0%	369
8	6-7%	6.48%	50.0%	1,670
9	7-8%	7.48%	21.0%	701
10	8-9%	8.40%	10.1%	338
11	9-10%	9.04%	5.7%	190
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.90%**		

Table 8E.1.9 Service Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%	3.89%	3.6%	530

6	4-5%	4.40%	18.2%	2,645
7	5-6%	5.57%	34.3%	4,990
8	6-7%	6.42%	20.6%	2,994
9	7-8%	7.52%	12.9%	1,878
10	8-9%	8.63%	8.2%	1,192
11	9-10%	9.16%	2.2%	324
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.05%**		

Table 8E.1.10 All Commercial Sectors Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%	3.76%	5.0%	3646
6	4-5%	4.54%	16.2%	11803
7	5-6%	5.50%	25.6%	18677
8	6-7%	6.43%	20.9%	15221
9	7-8%	7.45%	13.0%	9478
10	8-9%	8.54%	11.7%	8503
11	9-10%	9.41%	4.0%	2890
12	10-11%	10.40%	1.5%	1109
13	11-12%	11.21%	0.7%	531
14	12-13%	12.45%	1.1%	786
15	≥13%	13.88%	0.5%	342
Weighted Average		**6.45%**		

Table 8E.1.11 Industrial Sectors Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%	1.61%	0.0%	13
4	2-3%	2.67%	0.1%	76
5	3-4%	3.67%	2.0%	1,454
6	4-5%	4.60%	8.4%	6,013
7	5-6%	5.53%	22.7%	16,190
8	6-7%	6.46%	22.5%	16,028
9	7-8%	7.53%	16.1%	11,490

10	8-9%	8.46%	19.2%	13,691
11	9-10%	9.51%	5.4%	3,850
12	10-11%	10.38%	2.5%	1,814
13	11-12%	11.62%	0.5%	328
14	12-13%	12.51%	0.4%	272
15	≥13%			
Weighted Average		**6.90%**		

Table 8E.1.12 Agriculture Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%			
7	5-6%			
8	6-7%	6.69%	100.0%	207
9	7-8%			
10	8-9%			
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.69%**		

Table 8E.1.13 R.E.I.T./Property Management Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%			
4	2-3%			
5	3-4%			
6	4-5%	4.86%	4.9%	179
7	5-6%	5.45%	30.6%	1120
8	6-7%	6.47%	45.1%	1648
9	7-8%	7.59%	14.5%	529
10	8-9%	8.30%	3.3%	121
11	9-10%	9.27%	1.3%	47
12	10-11%	10.04%	0.3%	11

13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**7.93%**		

Table 8E.1.14 Investor-Owned Utility Sector Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of companies)	# of Companies
1	<0%			
2	0-1%			
3	1-2%	1.67%	0.6%	13
4	2-3%	2.56%	0.8%	16
5	3-4%	3.66%	39.1%	807
6	4-5%	4.31%	49.7%	1026
7	5-6%	5.37%	6.7%	138
8	6-7%	6.39%	2.3%	47
9	7-8%	7.18%	0.9%	19
10	8-9%			
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	≥13%			
Weighted Average		**6.00%**		

Table 8E.1.15 State/Local Government Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of years)	# of Years
1	<0%			
2	0-1%			
3	1-2%	1.6%	15.6%	5
4	2-3%	2.5%	25.0%	8
5	3-4%	3.6%	43.8%	14
6	4-5%	4.1%	6.3%	2
7	5-6%	5.3%	9.4%	3
8	6-7%			
9	7-8%			
10	8-9%			
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	>13%			
Weighted Average		**3.21%**		

Table 8E.1.16 Federal Government Discount Rate Distribution

Bin	Bin Range	Bin Average Discount Rate	Weight (% of months)	# of Months
1	<0%	-0.5%	5.2%	18
2	0-1%	0.5%	21.8%	76
3	1-2%	1.6%	17.8%	62
4	2-3%	2.5%	20.7%	72
5	3-4%	3.5%	20.7%	72
6	4-5%	4.3%	13.8%	48
7	5-6%			
8	6-7%			
9	7-8%			
10	8-9%			
11	9-10%			
12	10-11%			
13	11-12%			
14	12-13%			
15	>13%			
Weighted Average		**2.20%**		

8E.2 ASSIGNMENT OF DETAILED DATA TO AGGREGATE SECTORS FOR DISCOUNT RATE ANALYSIS

Table 8E.2.1 Detailed Industries Assigned to Each Aggregate CBECS PBA Sector

Aggregate Sector for CBECS Mapping	Detailed Sector Names as Provided in Damodaran Online Data Sets (1998-2018)
Education	Education; Educational Services
Food Sales	Food Wholesalers; Grocery; Retail (Grocery and Food); Retail/Wholesale Food
Food Service	Restaurant; Restaurant/Dining
Health Care	Healthcare Facilities; Healthcare Information; Healthcare Services; Healthcare Support Services; Healthcare Information and Technology; Hospitals/Healthcare Facilities; Medical Services
Lodging	Hotel/Gaming
Mercantile	Drugstore; Retail (Automotive); Retail (Building Supply); Retail (Distributors); Retail (General); Retail (Hardlines); Retail (Softlines); Retail (Special Lines); Retail Automotive; Retail Building Supply; Retail Store
Office	Advertising; Bank; Bank (Canadian); Bank (Midwest); Bank (Money Center); Banks (Regional); Broadcasting; Brokerage & Investment Banking; Business & Consumer Services; Cable TV; Computer Services; Computer Software; Computer Software/Svcs; Diversified; Diversified Co.; E-Commerce; Human Resources; Insurance (General); Insurance (Life); Insurance (Prop/Cas.); Internet; Investment Co.; Investment Co.(Foreign); Investment Companies; Investments & Asset Management; Property Management; Public/Private Equity; R.E.I.T.; Real Estate (Development); Real Estate (General/Diversified); Real Estate (Operations & Services); Reinsurance; Retail (Internet); Retail (Online); Securities Brokerage; Software (Entertainment); Software (Internet); Software (System & Application); Telecom. Utility; Thrift
Public Assembly	Entertainment; Recreation
Service	Financial Svcs.; Financial Svcs. (Div.); Financial Svcs. (Non-bank & Insurance); Foreign Telecom.; Funeral Services; Industrial Services; Information Services; Internet software and services; IT Services; Office Equip/Supplies; Office Equipment & Services; Oilfield Svcs/Equip.; Pharmacy Services; Telecom. Services

All Commercial	All detailed sectors included in: Education, Food Sales, Food Service, Health Care, Mercantile, Office, Public Assembly, Service
Industrial	Aerospace/Defense; Air Transport; Aluminum; Apparel; Auto & Truck; Auto Parts; Auto Parts (OEM); Auto Parts (Replacement); Automotive; Beverage; Beverage (Alcoholic); Beverage (Soft); Biotechnology; Building Materials; Cement & Aggregates; Chemical (Basic); Chemical (Diversified); Chemical (Specialty); Coal; Coal & Related Energy; Computers/Peripherals; Construction; Construction Supplies; Copper; Drug; Drugs (Biotechnology); Drugs (Pharmaceutical); Electric Util. (Central); Electric Utility (East); Electric Utility (West); Electrical Equipment; Electronics; Electronics (Consumer & Office); Electronics (General); Engineering; Engineering & Const; Engineering/Construction; Entertainment Tech; Environmental; Environmental & Waste Services; Food Processing; Foreign Electronics; Furn/Home Furnishings; Gold/Silver Mining; Green & Renewable Energy; Healthcare Equipment; Healthcare Products; Heavy Construction; Heavy Truck & Equip; Heavy Truck/Equip Makers; Home Appliance; Homebuilding; Household Products; Machinery; Manuf. Housing/RV; Maritime; Med Supp Invasive; Med Supp Non-Invasive; Medical Supplies; Metal Fabricating; Metals & Mining; Metals & Mining (Div.); Natural Gas (Div.); Natural Gas Utility; Newspaper; Oil/Gas (Integrated); Oil/Gas (Production and Exploration); Oil/Gas Distribution; Packaging & Container; Paper/Forest Products; Petroleum (Integrated); Petroleum (Producing); Pharma & Drugs; Pipeline MLPs; Power; Precious Metals; Precision Instrument; Publishing; Publishing & Newspapers; Railroad; Rubber& Tires; Semiconductor; Semiconductor Equip; Shipbuilding & Marine; Shoe; Steel; Steel (General); Steel (Integrated); Telecom (Wireless); Telecom. Equipment; Textile; Tire & Rubber; Tobacco; Toiletries/Cosmetics; Transportation; Transportation (Railroads); Trucking; Utility (Foreign); Utility (General); Utility (Water); Water Utility; Wireless Networking
Agriculture	Farming/Agriculture
Utilities	Natural Gas Utility; Utility (Foreign); Utility (General); Utility (Water); Water Utility
R.E.I.T. / Property	Property Management; R.E.I.T.; Real Estate (Development); Real Estate (General/Diversified); Real Estate (Operations & Services)

APPENDIX 10A. NATIONAL IMPACTS ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDIX 10A. NATIONAL IMPACTS ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS

10A.1 INTRODUCTION

This appendix presents results of calculating national energy savings (NES), and net present value (NPV) of potential standards for distribution transformers based on alternative national economic growth scenarios. The scenarios use the energy price and electricity sales for the high and the low economic growth cases in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2021* (*AEO 2120*).[1] In the national impact analysis (NIA) for distribution transformers described in chapter 10, DOE used the reference case in *AE O2021*.

Figure 10A.1.1 and Figure 10A.1.2 show the forecasts for electricity prices and electricity sales under the three economic growth scenarios considered in the *AEO*. *AEO 2021* provides a forecast to 2050. To estimate trends to the end of DOE's forecast period for distribution transformers (2050), DOE followed guidelines that the EIA has provided to the Federal Energy Management Program, which call for using the average rate of change for electricity prices during 2040–2050.

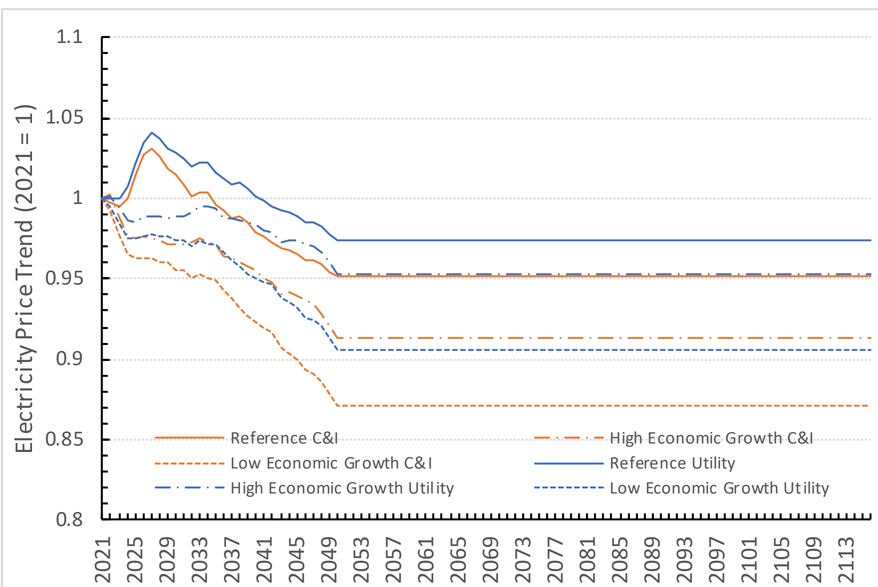


Figure 10A.1.1 Forecasts for Electricity Prices Under Three *AEO 2021* Economic Growth Scenarios

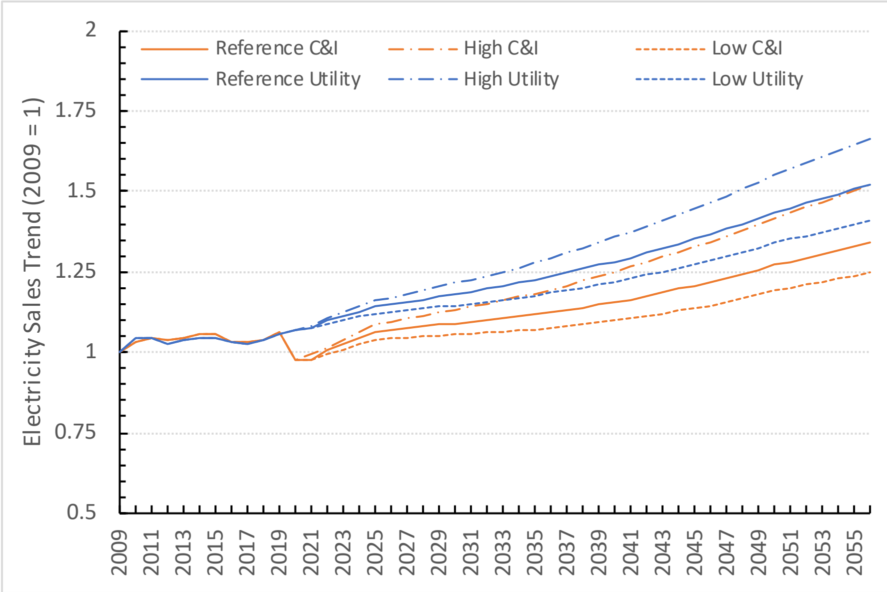


Figure 10A.1.2 Forecasts for Electricity Sales Under Three *AEO 2021* Economic Growth Scenarios

10A.2 RESULTS FOR ECONOMIC GROWTH SCENARIOS

Table 10A.2.1 shows the cumulative national full-fuel-cycle energy savings in quadrillion British thermal units (quads) and the NWS in trillion gallons attributable to proposed standards based on *AEO 2021*'s high and low economic growth scenario. Data are cumulative to the end of the forecast period (2050) for the candidate standard levels (CSLs) being considered.

Table 10A.2.1 Economic Growth Scenarios: Cumulative National Full-Fuel-Cycle Energy (Quads)

EC	Type	Scenario	Candidate Standard Level				
			1	2	3	4	5
1	Liquid-immersed, 1-Phase	High Economic Growth	(0.18)	0.72	2.69	3.82	4.08
		Low Economic Growth	(0.16)	0.65	2.40	3.41	3.64
		Reference	(0.17)	0.68	2.53	3.59	3.84
2	Liquid-immersed, 3-Phase	High Economic Growth	0.64	1.49	1.64	1.73	2.02
		Low Economic Growth	0.57	1.33	1.46	1.54	1.80
		Reference	0.60	1.40	1.54	1.63	1.90
3	Low-voltage Dry-type, 1-Phase	High Economic Growth	0.01	0.02	0.03	0.03	0.08
		Low Economic Growth	0.01	0.02	0.02	0.03	0.07
		Reference	0.01	0.02	0.03	0.03	0.07
4	Low-voltage Dry-type, 3-Phase	High Economic Growth	0.04	0.06	0.57	1.01	1.14
		Low Economic Growth	0.03	0.05	0.49	0.88	1.00
		Reference	0.03	0.05	0.52	0.93	1.05
5	Medium-voltage Dry-Type 45 BIL, 1-Phase	High Economic Growth	0.00	0.00	0.00	0.00	0.00
		Low Economic Growth	0.00	0.00	0.00	0.00	0.00
		Reference	0.00	0.00	0.00	0.00	0.00
6	Medium-voltage Dry-Type 45 BIL, 3-Phase	High Economic Growth	0.00	0.00	0.01	0.01	0.01
		Low Economic Growth	0.00	0.00	0.01	0.01	0.01
		Reference	0.00	0.00	0.01	0.01	0.01
7	Medium-voltage Dry-Type 95 BIL, 1-Phase	High Economic Growth	0.00	0.00	0.00	0.00	0.00
		Low Economic Growth	0.00	0.00	0.00	0.00	0.00
		Reference	0.00	0.00	0.00	0.00	0.00
8	Medium-voltage Dry-Type 95 BIL, 3-Phase	High Economic Growth	0.01	0.02	0.12	0.13	0.15
		Low Economic Growth	0.01	0.02	0.11	0.11	0.13
		Reference	0.01	0.02	0.11	0.12	0.14
9	Medium-voltage Dry-Type 125 BIL, 1-Phase	High Economic Growth	0.00	0.00	0.00	0.00	0.00
		Low Economic Growth	0.00	0.00	0.00	0.00	0.00
		Reference	0.00	0.00	0.00	0.00	0.00
10	Medium-voltage Dry-Type 125 BIL, 3- Phase	High Economic Growth	0.01	0.01	0.08	0.09	0.11
		Low Economic Growth	0.01	0.01	0.07	0.08	0.09
		Reference	0.01	0.01	0.08	0.09	0.10

Table 10A.2.2 Economic Growth Scenarios: Cumulative Net Present Value of Consumer Benefits for 3-Percent Percent Discount Rates (billion 2020$)

EC	Type	Scenario	Candidate Standard Level				
			1	2	3	4	5
1	Liquid-immersed, 1-Phase	High Economic Growth	(0.41)	(0.14)	1.24	1.70	(2.72)
		Low Economic Growth	(0.37)	(0.14)	1.07	1.47	(2.54)
		Reference	(0.39)	(0.14)	1.15	1.58	(2.62)
2	Liquid-immersed, 3-Phase	High Economic Growth	1.02	1.60	1.78	2.47	1.47
		Low Economic Growth	0.91	1.42	1.58	2.20	1.29
		Reference	0.96	1.50	1.67	2.32	1.37
3	Low-voltage Dry-type, 1-Phase	High Economic Growth	0.07	0.14	0.17	0.10	0.58
		Low Economic Growth	0.05	0.11	0.13	0.06	0.43
		Reference	0.06	0.12	0.14	0.08	0.50
4	Low-voltage Dry-type, 3-Phase	High Economic Growth	0.24	0.37	1.98	7.00	7.56
		Low Economic Growth	0.18	0.27	1.26	5.13	5.51
		Reference	0.21	0.32	1.59	5.97	6.43
5	Medium-voltage Dry-Type 45 BIL, 1-Phase	High Economic Growth	0.00	0.00	0.01	0.01	0.01
		Low Economic Growth	0.00	0.00	0.00	0.01	0.01
		Reference	0.00	0.00	0.01	0.01	0.01
6	Medium-voltage Dry-Type 45 BIL, 3-Phase	High Economic Growth	0.00	0.00	0.05	0.06	0.05
		Low Economic Growth	0.00	0.00	0.03	0.04	0.03
		Reference	0.00	0.00	0.04	0.05	0.04
7	Medium-voltage Dry-Type 95 BIL, 1-Phase	High Economic Growth	(0.00)	(0.00)	0.01	0.01	0.01
		Low Economic Growth	(0.00)	(0.00)	0.01	0.01	0.00
		Reference	(0.00)	(0.00)	0.01	0.01	0.01
8	Medium-voltage Dry-Type 95 BIL, 3-Phase	High Economic Growth	(0.02)	(0.03)	0.38	0.38	0.14
		Low Economic Growth	(0.03)	(0.04)	0.21	0.20	(0.02)
		Reference	(0.03)	(0.04)	0.29	0.29	0.06
9	Medium-voltage Dry-Type 125 BIL, 1-Phase	High Economic Growth	0.00	0.00	0.00	0.00	0.00
		Low Economic Growth	0.00	0.00	0.00	0.00	0.00
		Reference	0.00	0.00	0.00	0.00	0.00
10	Medium-voltage Dry-Type 125 BIL, 3- Phase	High Economic Growth	0.01	(0.01)	0.50	0.50	0.36
		Low Economic Growth	0.00	(0.02)	0.34	0.33	0.20
		Reference	0.01	(0.01)	0.41	0.41	0.28

Table 10A.2.3 Economic Growth Scenarios: Cumulative Net Present Value of Consumer Benefits for 7-Percent Discount Rates (billion 2020$)

EC	Type	Scenario	Candidate Standard Level				
			1	2	3	4	5
1	Liquid-immersed, 1-Phase	High Economic Growth	(0.34)	(0.36)	(0.33)	(0.63)	(3.76)
		Low Economic Growth	(0.31)	(0.34)	(0.32)	(0.60)	(3.45)
		Reference	(0.32)	(0.35)	(0.32)	(0.61)	(3.60)
2	Liquid-immersed, 3-Phase	High Economic Growth	0.23	0.37	0.36	0.46	(0.80)
		Low Economic Growth	0.21	0.33	0.32	0.41	(0.75)
		Reference	0.22	0.35	0.34	0.43	(0.77)
3	Low-voltage Dry-type, 1-Phase	High Economic Growth	0.02	0.04	0.05	0.01	0.15
		Low Economic Growth	0.02	0.03	0.04	(0.00)	0.11
		Reference	0.02	0.04	0.04	0.00	0.13
4	Low-voltage Dry-type, 3-Phase	High Economic Growth	0.07	0.09	0.15	1.68	1.77
		Low Economic Growth	0.05	0.07	(0.02)	1.19	1.23
		Reference	0.06	0.08	0.06	1.41	1.47
5	Medium-voltage Dry-Type 45 BIL, 1-Phase	High Economic Growth	0.00	0.00	0.00	0.00	0.00
		Low Economic Growth	0.00	0.00	0.00	0.00	0.00
		Reference	0.00	0.00	0.00	0.00	0.00
6	Medium-voltage Dry-Type 45 BIL, 3-Phase	High Economic Growth	0.00	(0.00)	0.01	0.01	0.00
		Low Economic Growth	(0.00)	(0.00)	0.01	0.01	(0.00)
		Reference	0.00	(0.00)	0.01	0.01	0.00
7	Medium-voltage Dry-Type 95 BIL, 1-Phase	High Economic Growth	(0.00)	(0.00)	0.00	0.00	0.00
		Low Economic Growth	(0.00)	(0.00)	0.00	0.00	(0.00)
		Reference	(0.00)	(0.00)	0.00	0.00	(0.00)
8	Medium-voltage Dry-Type 95 BIL, 3-Phase	High Economic Growth	(0.03)	(0.05)	(0.02)	(0.04)	(0.18)
		Low Economic Growth	(0.03)	(0.05)	(0.06)	(0.07)	(0.21)
		Reference	(0.03)	(0.05)	(0.04)	(0.06)	(0.19)
9	Medium-voltage Dry-Type 125 BIL, 1-Phase	High Economic Growth	(0.00)	(0.00)	(0.00)	0.00	0.00
		Low Economic Growth	(0.00)	(0.00)	(0.00)	0.00	(0.00)
		Reference	(0.00)	(0.00)	(0.00)	0.00	(0.00)
10	Medium-voltage Dry-Type 125 BIL, 3-Phase	High Economic Growth	(0.01)	(0.03)	0.07	0.06	(0.02)
		Low Economic Growth	(0.01)	(0.03)	0.04	0.02	(0.05)
		Reference	(0.01)	(0.03)	0.05	0.04	(0.04)

REFERENCES

1 U.S. Energy Information Administration. *Annual Energy Outlook 2021 with Projections to 2050.* September 2021. Washington, D.C. Report Number: DOE/EIA-0383(2021). (Last accessed: August, 2021.)

APPENDIX 10B. FULL-FUEL-CYCLE ANALYSIS

TABLE OF CONTENTS

LIST OF TABLES

APPENDIX 10B. FULL-FUEL-CYCLE ANALYSIS

10B.1 INTRODUCTION

This appendix summarizes the methods the U.S. Department of Energy (DOE) used to calculate the estimated full-fuel-cycle (FFC) energy savings from potential energy conservation standards. The FFC measure includes point-of-use (site) energy; the energy losses associated with generation, transmission, and distribution of electricity; and the energy consumed in extracting, processing, and transporting or distributing primary fuels. DOE's method of analysis previously encompassed only site energy and the energy lost through generation, transmission, and distribution of electricity. In 2011 DOE announced its intention, based on recommendations from the National Academy of Sciences, to use FFC measures of energy use and emissions when analyzing proposed energy conservation standards.[1] This appendix summarizes the methods DOE used to incorporate impacts of the full fuel cycle into the analysis.

In the national energy savings calculation, DOE estimates the site, primary and full-fuel-cycle (FFC) energy consumption for each standard level, for each year in the analysis period. DOE defines these quantities as follows:

- Site energy consumption is the physical quantity of fossil fuels or electricity consumed at the site where the end-use service is provided.[a] The site energy consumption is used to calculate the energy cost input to the NPV calculation.
- Primary energy consumption is defined by converting the site fuel use from physical units, for example cubic feet for natural gas, or kWh for electricity, to common energy units (million Btu or MMBtu). For electricity the conversion factor is a marginal heat rate that incorporates losses in generation, transmission and distribution, and depends on the sector, end use and year.
- The full-fuel-cycle (FFC) energy use is equal to the primary energy use plus the energy consumed "upstream" of the site in the extraction, processing and distribution of fuels. The FFC energy use was calculated by applying a fuel-specific FFC energy multiplier to the primary energy use.

For electricity from the grid, site energy is measured in terawatt-hours (TWh). The primary energy of a unit of grid electricity is equal to the heat content of the fuels used to generate that electricity, including transmission and distribution losses.[b] DOE typically measures the primary energy associated with the power sector in quads (quadrillion Btu). Both primary fuels and electricity are used in upstream activities. The treatment of electricity in full-fuel-cycle analysis must distinguish between electricity generated by fossil fuels and electricity generated from renewable sources (wind, solar, and hydro). For the former, the upstream fuel cycle relates

[a] For fossil fuels, this is the site of combustion of the fuel.
[b] For electricity sources like nuclear energy and renewable energy, the primary energy is calculated using the convention described below.

to the fuel consumed at the power plant. There is no upstream component for the latter, because no fuel *per se* is used.

10B.2 SITE-TO-PRIMARY ENERGY FACTORS

DOE uses heat rates to convert site electricity savings in TWh to primary energy savings in quads. The heat rates are developed as a function of the sector, end-use and year of the analysis period. For this analysis DOE uses output of the DOE/Energy Information Administration (EIA)'s National Energy Modeling System (NEMS).[2] EIA uses the NEMS model to produce the *Annual Energy Outlook* (*AEO*). DOE's approach uses the most recently available edition, in this case *AEO 2021*.[3] The *AEO* publication includes a reference case and a series of side cases incorporating different economic and policy scenarios. DOE calculates marginal heat rates as the ratio of the change in fuel consumption to the change in generation for each fossil fuel type, where the change is defined as the difference between the reference case and the side case. DOE calculates a marginal heat rate for each of the principal fuel types: coal, natural gas and oil. DOE uses the EIA convention of assigning a heat rate of 10.5 Btu/Wh to nuclear power and 9.5 Btu/Wh to electricity from renewable sources.

DOE multiplied the fuel share weights for sector and end-use, described in appendix 15A of this TSD, by the fuel specific marginal heat rates, and summed over all fuel types, to define a heat rate for each sector/end-use. This step incorporates the transmission and distribution losses. In equation form:

$$h(u,y) = (1 + TDLoss)*\sum_{r,f} g(r,f,y)\, H(f,y)$$

Where:

TDLoss	=	the fraction of total generation that is lost in transmission and distribution, equal to 0.07037
U	=	an index representing the sector/end-use (e.g. commercial cooling)
Y	=	the analysis year
F	=	the fuel type
H(f,y)	=	the fuel-specific heat rate
g(r,f,y)	=	the fraction of generation provided by fuel type *f* for end-use *u* in year *y*
h(u,y)	=	the end-use specific marginal heat rate

The sector/end-use specific heat rates are shown in Table 10B.2.1. These heat rates convert site electricity to primary energy in quads; i.e., the units used in the table are quads per TWh.

Table 10B.2.1 Electric Power Heat Rates (MMBtu/MWh) by Sector and End-Use

	2025	2030	2035	2040	2045	2050+
Residential						
Clothes Dryers	9.484	9.258	9.257	9.205	9.153	9.133
Cooking	9.473	9.246	9.245	9.193	9.142	9.122
Freezers	9.496	9.267	9.264	9.211	9.159	9.138
Lighting	9.511	9.289	9.290	9.238	9.186	9.167

Refrigeration	9.496	9.267	9.264	9.212	9.159	9.138
Space Cooling	9.397	9.146	9.133	9.080	9.026	9.001
Space Heating	9.526	9.306	9.308	9.256	9.204	9.185
Water Heating	9.493	9.270	9.271	9.219	9.168	9.149
Other Uses	9.484	9.259	9.258	9.206	9.154	9.134
Commercial						
Cooking	9.409	9.184	9.185	9.135	9.085	9.065
Lighting	9.426	9.200	9.200	9.150	9.100	9.079
Office Equipment (Non-Pc)	9.374	9.145	9.145	9.095	9.046	9.026
Office Equipment (Pc)	9.374	9.145	9.145	9.095	9.046	9.026
Refrigeration	9.476	9.250	9.249	9.197	9.146	9.126
Space Cooling	9.378	9.125	9.111	9.058	9.005	8.979
Space Heating	9.532	9.313	9.314	9.262	9.210	9.191
Ventilation	9.478	9.253	9.252	9.200	9.149	9.129
Water Heating	9.409	9.184	9.186	9.136	9.087	9.067
Other Uses	9.389	9.161	9.162	9.111	9.062	9.042
Industrial						
All Uses	9.389	9.161	9.162	9.111	9.062	9.042

10B.3 FFC METHODOLOGY

The methods used to calculate FFC energy use are summarized here. The mathematical approach to determining FCC is discussed in Coughlin (2012).[4] Details related to the modeling of the fuel production chain are presented in Coughlin (2013).[5]

When all energy quantities are normalized to the same units, FFC energy use can be represented as the product of the primary energy use and an FFC multiplier. Mathematically the FFC multiplier is a function of a set of parameters that represent the energy intensity and material losses at each stage of energy production. Those parameters depend only on physical data, so the calculations require no assumptions about prices or other economic factors. Although the parameter values may differ by geographic region, this analysis utilizes national averages.

The fuel cycle parameters are defined as follows.

- a_x is the quantity of fuel x burned per unit of electricity produced for grid electricity. The calculation of a_x includes a factor to account for losses incurred through the transmission and distribution systems.
- b_y is the amount of grid electricity used in producing fuel y, in MWh per physical unit of fuel y.
- c_{xy} is the amount of fuel x consumed in producing one unit of fuel y.
- q_x is the heat content of fuel x (MBtu/physical unit).

All the parameters are calculated as functions of an annual time step; hence, when evaluating the effects of potential new standards, a time series of annual values is used to estimate the FFC energy and emissions savings in each year of the analysis period and cumulatively.

The FFC multiplier is denoted μ (mu). A separate multiplier is calculated for each fuel used on site. Also calculated is a multiplier for electricity that reflects the fuel mix used in its generation. The multipliers are dimensionless numbers applied to primary energy savings to obtain the FFC energy savings. The upstream component of the energy savings is proportional to (μ-1). The fuel type is denoted by a subscript on the multiplier μ.

The method for performing the full-fuel-cycle analysis utilizes data and projections published in the *AEO 2021*. Table 10B.3.1 summarizes the data used as inputs to the calculation of various parameters. The column titled "*AEO* Table" gives the name of the table that provided the reference data.

Table 10B.3.1 Dependence of FFC Parameters on *AEO* Inputs

Parameter(s)	Fuel(s)	*AEO* Table	Variables
q_x	All	Conversion factors	MMBtu per physical unit
a_x	All	Electricity supply, disposition, prices, and emissions Energy consumption by sector and source	Generation by fuel type Electric energy consumption by the power sector
b_c, c_{nc}, c_{pc}	Coal	Coal production by region and type	Coal production by type and sulfur content
b_p, c_{np}, c_{pp}	Petroleum	Refining industry energy consumption Liquid fuels supply and disposition International liquids supply and disposition Oil and gas supply	Refining-only energy use Crude supply by source Crude oil imports Domestic crude oil production
c_{nn}	Natural gas	Oil and gas supply Natural gas supply, disposition, and prices	U.S. dry gas production Pipeline, lease, and plant fuel
z_x	All	Electricity supply, disposition, prices, and emissions	Power sector emissions

The *AEO 2021* does not provide all the information needed to estimate total energy use in the fuel production chain. Coughlin (2013) describes the additional data sources needed to complete the analysis. The time dependence in the FFC multipliers, however, arises exclusively from variables taken from the *AEO*.

10B.4 ENERGY MULTIPLIERS FOR THE FULL FUEL CYCLE

FFC energy multipliers for selected years are presented in Table 10B.4.1. The 2050 value was held constant for the analysis period beyond 2050, which is the last year in the *AEO 2021* projection. The multiplier for electricity reflects the shares of various primary fuels in total electricity generation throughout the forecast period.

Table 10B.4.1 Energy Multipliers for the Full Fuel Cycle (Based on *AEO 2021*)

	2025	**2030**	**2035**	**2040**	**2045**	**2050+**
Electricity	1.042	1.039	1.038	1.037	1.038	1.037

REFERENCES

1. U.S. Department of Energy. *Federal Register*. August 18, 2011. vol. 76, no. 160: pp. 51281–51289. (Last accessed September 1, 2020.) http://www.gpo.gov/fdsys/pkg/FR-2011-08-18/pdf/FR-2011-08-18.pdf.

2. U.S. Department of Energy–Energy Information Administration. *The National Energy Modeling System: An Overview 2009*. 2009. Report No. DOE/EIA-0581(2009). (Last accessed September 1, 2020.) http://www.eia.gov/forecasts/archive/0581(2009).pdf.

3. U.S. Energy Information Administration. *Annual Energy Outlook 2021 with Projections to 2050*. 2021. Washington, D.C. Report No. AEO2021. (Last accessed March 18, 2021.) https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf.

4. Coughlin, K. A Mathematical Analysis of Full Fuel Cycle Energy Use. *Energy*. 2012. 37(1): pp. 698–708.

5. Coughlin, K. *Projections of Full-Fuel-Cycle Energy and Emissions Metrics*. 2013. Lawrence Berkeley National Laboratory: Berkeley, CA. Report No. LBNL-6025E. (Last accessed September 1, 2020.) https://eta-publications.lbl.gov/sites/default/files/lbnl6025e_ffc.pdf.