Federal Register

Thursday,
July 29, 2004

Part II

Department of Energy

Office of Energy Efficiency and Renewable Energy

10 CFR Part 430

Energy Conservation Program for Commercial and Industrial Equipment: Energy Conservation Standards for Distribution Transformers; Proposed Rule

DEPARTMENT OF ENERGY

Office of Energy Efficiency and Renewable Energy

10 CFR Part 430

[Docket No. EE–RM/STD–00–550]

RIN 1904–AB08

Energy Conservation Program for Commercial and Industrial Equipment: Energy Conservation Standards for Distribution Transformers

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Advance notice of proposed rulemaking, public meeting and webcast.

SUMMARY: The Energy Policy and Conservation Act (EPCA or the Act) authorizes the Department of Energy (DOE or the Department) to establish energy conservation standards for various consumer products and commercial and industrial equipment, including distribution transformers, if DOE determines that energy conservation standards would be technologically feasible and economically justified, and would result in significant energy savings. The Department publishes this Advance Notice of Proposed Rulemaking (ANOPR) to consider establishing energy conservation standards for distribution transformers and to announce a public meeting to receive comments on a variety of issues.

DATE: The Department will hold a webcast on August 10, 2004 from 1 p.m. to 4 p.m. If you are interested in participating in this event, please inform Sandy Beall at (202) 586–7574.

The Department will hold a public meeting on September 28, 2004, starting at 9 a.m., in Washington, DC. The Department must receive requests to speak at the public meeting no later than 4 p.m., September 14, 2004. The Department must receive a signed original and an electronic copy of statements to be given at the public meeting no later than 4 p.m., September 21, 2004.

The Department will accept comments, data, and information regarding the ANOPR before or after the public meeting, but no later than November 9, 2004. *See* section IV, ''Public Participation,'' of this ANOPR for details.

ADDRESSES: The public meeting will be held at the U.S. Department of Energy, Forrestal Building, Room 1E–245, 1000 Independence Avenue, SW., Washington, DC. (Please note that foreign nationals visiting DOE Headquarters are subject to advance security screening procedures, requiring a 30-day advance notice. If you are a foreign national and wish to participate in the workshop, please inform DOE of this fact as soon as possible by contacting Ms. Brenda Edwards-Jones at (202) 586–2945 so that the necessary procedures can be completed.)

You may submit comments, identified by docket number EE–RM/STD–00–550 and/or RIN number 1904–AB08, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *E-mail: TransformerANOPRComment@ee.doe.gov*. Include EE–RM/STD–00–550 and/or RIN 1904–AB08 in the subject line of the message.
- *Mail:* Ms. Brenda Edwards-Jones, U.S. Department of Energy, Building Technologies Program, Mailstop EE–2J, ANOPR for Distribution Transformers, EE–RM/STD–00–550 and/or RIN 1904–AB08, 1000 Independence Avenue, SW., Washington, DC, 20585–0121. Telephone: (202) 586–2945. Please submit one signed paper original.
- *Hand Delivery/Courier:* Ms. Brenda Edwards-Jones, U.S. Department of Energy, Building Technologies Program, Room 1J–018, 1000 Independence Avenue, SW., Washington, DC, 20585.

Instructions: All submissions received must include the agency name and docket number or Regulatory Information Number (RIN) for this rulemaking. For detailed instructions on submitting comments and additional information on the rulemaking process, see section IV of this document (Public Participation).

Docket: For access to the docket to read background documents or comments received, go to the U.S. Department of Energy, Forrestal Building, Room 1J–018 (Resource Room of the Building Technologies Program), 1000 Independence Avenue, SW., Washington, DC, (202) 586–9127, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Please call Ms. Brenda Edwards-Jones at the above telephone number for additional information regarding visiting the Resource Room. Please note: The Department's Freedom of Information Reading Room (Room 1E–190 at the Forrestal Building) is no longer housing rulemaking materials.

FOR FURTHER INFORMATION CONTACT: Ron Lewis, Project Manager, Energy Conservation Standards for Distribution Transformers, Docket No. EE–RM/STD–00–550, EE–2J / Forrestal Building, U.S. Department of Energy, Office of Building Technologies, EE–2J, 1000 Independence Avenue SW., Washington, DC, 20585–0121, (202) 586–8423. E-mail: *Ronald.Lewis@ee.doe.gov*.

Thomas B. DePriest, Esq., U.S. Department of Energy, Office of General Counsel, Forrestal Building, Mail Station GC–72, 1000 Independence Avenue, SW., Washington, DC, 20585, (202) 586–9507. E-mail: *Thomas.DePriest@hq.doe.gov*.

SUPPLEMENTARY INFORMATION:

I. Introduction

A. Purpose of the ANOPR

The purpose of this ANOPR is to provide interested persons with an opportunity to comment on:

(i) The product classes that the Department is planning to analyze;

(ii) The analytical framework, models, and tools (*e.g.* life-cycle cost (LCC) and national energy savings (NES) spreadsheets) used by the Department in performing analyses of the impacts of energy conservation standards;

(iii) The results of the engineering analysis, the LCC and payback period (PBP) analyses, and the national impact analysis presented in the ANOPR Technical Support Document (TSD): Energy Efficiency Standards for Commercial and Industrial Equipment: Electric Distribution Transformers; and

(iv) The candidate energy conservation standard levels that the Department has developed from these analyses.

B. Summary of the Analysis

The Energy Policy and Conservation Act (42 U.S.C. 6317) authorizes DOE to consider establishing energy conservation standards for various consumer products and commercial and industrial equipment, including distribution transformers, which are the subject of this ANOPR.

The Department conducted eight analyses for this ANOPR: Market and technology assessment, screening analysis, engineering analysis, energy use and end-use load characterization, markups for equipment price determination, LCC and PBP analyses, shipments analysis, and national impact analysis. Three of the above analyses produce key results while the other five produce intermediate inputs. The three key analyses conducted are summarized briefly below: (1) Engineering; (2) life-cycle cost and payback periods; and (3) national impacts.

1. Engineering Analysis

The engineering analysis estimates the relationship between cost and efficiency for selected distribution transformers. The Department structured the engineering analysis around 13 groupings (termed ''engineering design lines') of similarly built distribution transformers. The Department then identified one representative unit from each grouping, conducted software design runs on those units, estimated the material and labor costs, and calculated the performance of each design. Markups were applied to the manufacturer costs to arrive at the manufacturer's selling price. In this way, the Department constructed manufacturer-selling-price versus efficiency curves for the representative units from each of the 13 engineering design lines. These relationship curves are a critical input to the LCC analysis.

2. Life-Cycle Cost and Payback Period Analyses

The life-cycle costs (LCC) and payback period (PBP) analyses determine the economic impact of potential standards on individual consumers. LCC and PBP calculations are conducted on each of the representative units from the 13 engineering design lines. The LCC calculation considers the total installed cost of equipment manufactured to comply with potential energy efficiency standards (equipment purchase price plus installation cost), the operating expenses of such equipment (energy and maintenance costs), the lifetime of the equipment, and uses the discount rate that reflects the consumer cost of capital to put the LCC in current year dollars. The PBP is a calculation to determine the period of time necessary to recover the higher purchase price of more efficient transformers through the operating cost savings. The PBP analysis provides a simplified estimate of the PBP as the incremental cost of a more efficient transformer divided by the first year operating savings. Both the LCC and PBP analyses consider that the consumer is an electric utility or commercial/industrial entity, responsible for both the purchase price and operating costs of the distribution transformer.

The foundation of the LCC and PBP analyses is the transformer design and cost information from the engineering analysis. Most other inputs to the LCC and PBP analyses are characterized by probability distributions. These input probability distributions, combined with a baseline scenario of current market conditions, generate probability distributions of LCC and PBP results using Monte Carlo statistical analysis methods.

One of the most critical inputs to the LCC and PBP analyses is the price of electricity. The Department derived two sets of electricity prices to estimate annual energy expenses: A tariff-based estimate to characterize the prices to the commercial and industrial owners of dry-type transformers and a utility-market-based estimate to characterize the electricity costs to owners, which are typically utilities, of liquid-immersed transformers.

3. National Impact Analysis

The national impact analysis assesses the net present value (NPV) of national economic impacts as well as the NES. The Department calculated both the NES and NPV for a given standard level as the difference between a base case (without new standards) and a standards case (with standards). National annual energy consumption by distribution transformers considered by the Department is determined by multiplying the number of distribution transformers in use by the average unit energy consumption. Cumulative energy savings are the sum of the annual NES results calculated over specified time periods. The national NPV is the sum over time of the discounted net cost savings due to energy savings associated with a proposed standard. The Department calculated net savings each year as the difference between total operating cost savings and increases in total installed costs for each candidate standard level. Cumulative NPV savings are the sum of the annual NPV calculated over specified time periods.

One of the most critical inputs to the NES and NPV calculation is the shipments forecast. The Department developed shipment projections for the base case and the candidate standard levels. The default scenario for both calculations differs between liquid-immersed and dry-type transformers. For liquid-immersed transformers, the Department determined that shipment projections in the standards cases would be slightly lower than those for the base case due to the higher installed cost of the more energy efficient distribution transformers in the standards case. For dry-type transformers, the Department determined that there would be no difference in shipment projections between the base case and standards cases.

Table I.1 summarizes the methodologies, key inputs and assumptions for each ANOPR analysis area. The table also presents the sections in this document that contain the analysis results.

TABLE I.1.—IN-DEPTH TECHNICAL ANALYSES CONDUCTED FOR THE ANOPR

Analysis area	Methodology	Key inputs	Key assumptions	ANOPR section for results
Engineering	Simplify population for analysis; create design option combinations; use design software to prepare a range of efficiency designs.	(1) Material costs for construction; (2) Design tolerances.	Maximum technologically feasible design for liquid-immersed is amorphous core, for a dry-type is laser-scribed.	Section II.C.5; presented in the TSD, Chapter 5.
LCC and PBP	Transformer-by-transformer analysis using representative models from simplified design lines.	(1) Cost /efficiency relationship from engineering analysis; (2) Baseline determination from purchase decision model; (3) Electricity prices and tariffs.	(1) Liquid-immersed subject to utility industry economics; (2) Dry-type subject to commercial/industrial economics.	Section II.F.4; results also presented in the TSD, Chapter 8.
National impact analysis.	Distribution transformer costs and energy consumption forecasted to 2035; combined with LCC results and mapped to product classes (1) Average values from the LCC analysis; (2) Historical shipment shipments estimate.	(1) Design line-to-product class mapping; (2) 0.75 power scaling rule.	Section II.H.4; results also presented in the TSD, Chapter 10.	

The Department consulted with stakeholders and published preliminary findings during the development and execution of the analyses shown in Table I.1. The Department invites further input from stakeholders on the methodologies, inputs, and assumptions presented in this document.

C. Authority

Title III of EPCA established an energy conservation program for consumer products other than automobiles. Amendments expanded Title III of EPCA to include certain commercial and industrial equipment, including distribution transformers. (42 U.S.C. 6311 *et seq.*) Specifically the Department's authority for this ANOPR is in 42 U.S.C. 6317.

Before the Department determines whether to adopt a proposed energy conservation standard, it will first solicit comments on the proposed standard. The Department will consider designing any new or amended standard to achieve the maximum improvement in energy efficiency that is technologically feasible and economically justified. (42 U.S.C. 6295 (o)(2)(A) and 42 U.S.C. 6317(c)) If a proposed standard is not designed to achieve the maximum improvement in energy efficiency or the maximum reduction in energy use that is technologically feasible, DOE will state the reasons for this in the proposed rule. To determine whether economic justification exists, the Department will review comments on the proposal and determine whether the benefits of the proposed standard exceed its burdens to the greatest extent practicable, while considering the following seven factors (*see* 42 U.S.C. 6295 (o)(2)(B)):

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

(2) The savings in operating costs throughout the estimated average life of the covered products in the type (or class) compared to any increase in the price, initial charges, or maintenance expenses for 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 imposition of the standard;

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

(6) The need for national energy conservation; and

(7) Other factors the Secretary considers relevant.

D. Background

1. History of Standards Rulemaking for Distribution Transformers

On October 22, 1997, the Secretary of Energy issued a determination that ''based on its analysis of the information now available, the Department has determined that energy conservation standards for transformers appear to be technologically feasible and economically justified, and are likely to result in significant savings.'' 62 FR 54809.

The Secretary's determination was based, in part, on analyses conducted by the Department of Energy's Oak Ridge National Laboratory (ORNL). In July 1996, ORNL published a report entitled Determination Analysis of Energy Conservation Standards for Distribution Transformers, ORNL–6847, which assessed options for setting energy conservation standards. That report was based on information from annual sales data, average load data, and surveys of existing and potential transformer efficiencies obtained from several organizations.

In September 1997, ORNL published a second report entitled Supplement to the ''Determination Analysis'' (ORNL–6847) and Analysis of the NEMA Efficiency Standard for Distribution Transformers, ORNL–6925. This report assessed the suggested efficiency levels contained in the then-newly published National Electrical Manufacturers Association (NEMA) Standards Publication No. TP 1–1996, Guide for Determining Energy Efficiency for Distribution Transformers, along with the efficiency levels previously considered by the Department in the determination study. The latest downloadable version of TP 1 is available at the NEMA Web site: *http://www.nema.org/index_nema.cfm/1427/47168E11–AA56–4B4E–9F329B339C23F115/.* In its supplemental assessment, ORNL used a more accurate analytical model and better transformer market and loading data developed following the publication of ORNL–6827. Downloadable versions of both ORNL reports are available on the DOE Web site at: *http://www.eere.energy.gov/buildings/appliance_standards/distribution_transformers.html.*

As a result of this positive determination, in 2000, the Department developed a Framework Document for Distribution Transformer Energy Conservation Standards Rulemaking, describing the procedural and analytic approaches that the Department anticipated using to evaluate the establishment of energy conservation standards for distribution transformers. This document is also available on the aforementioned DOE Web site. On November 1, 2000, the Department held a public workshop on the framework document to discuss the proposed analytical framework. Manufacturers, trade associations, electric utilities, environmental advocates, regulators, and other interested parties attended the framework document workshop, actively participating in discussions and showing their willingness to work with DOE on the process of analyzing possible efficiency standards. The major issues discussed were: definition of covered transformer products; definition of product classes; possible proprietary (patent) issues regarding amorphous metal; ties between efficiency improvements and installation costs; baseline and possible efficiency levels; base case trends under deregulation; transformer costs versus transformer prices; appropriate LCC sub-groups; LCC methods, *e.g.*, total owning cost (TOC); loading levels; utility impact analysis vis-a-vis deregulation; scope of environmental assessment; and harmonization of standards with other countries.

Stakeholder comments submitted during the framework document comment period elaborated upon the issues raised at the meeting and also addressed the following issues: Options for the screening analysis; approaches for the engineering analysis; discount rates; electricity prices; the number and basis for the efficiency levels to be analyzed; the NES and NPV analyses; the analysis of the effects of a potential standard on employment; the manufacturer impact assessment; and the timing of the analyses. The Department worked with its contractors to address these issues as well as those raised during the framework document workshop.

As part of the information gathering and sharing process, the Department met with manufacturers of liquid-immersed and dry-type distribution transformers during the first quarter of 2002. The Department met with companies that produced all types of distribution transformers, ranging from small to large manufacturers, and including both NEMA and non-NEMA members. The Department had four objectives for these meetings: (1) Solicit feedback on the methodology and findings presented in the draft engineering analysis update report that the Department posted on its Web site December 17, 2001; (2) get information and comments on production costs and manufacturing processes presented in the December 17, 2001, draft engineering analysis update report; (3) provide an opportunity, early in the rulemaking process, to express specific concerns to the Department; and (4) foster cooperation between the manufacturers and the Department.

There were five general issues discussed at each of these manufacturer site meetings: (1) Company overview and product offerings; (2) the structure of the engineering analysis, including the engineering design lines, which represent groupings of similarly built distribution transformers; (3) design option combinations for each of the representative transformers from the engineering design lines; (4) use of Optimized Program Services (OPS) distribution transformer design software; and (5) the 0.75 scaling rule, used to scale the costs and efficiencies of the representative units within each of the engineering design lines.

The Department incorporated the information gathered at the meetings into its engineering analysis, which is described in more detail in the engineering analysis part of this ANOPR (section II.C), as well as in Chapter 5 of the TSD. Following the publication of the ANOPR and the ANOPR public meeting, the Department may hold additional meetings with manufacturers as part of the consultative process for the manufacturer impact analysis (see section II.J).

As part of its pre-ANOPR analysis process, the Department posted several draft reports on its Web site to solicit stakeholder input. These reports are:

- The Department's initial engineering analysis for design line 1 (Distribution Transformer Rulemaking, Engineering Analysis Update, posted December 17, 2001). This document contains preliminary results of the engineering analysis for design line 1.
- The Department's initial screening analysis (Screening Analysis, posted March 5, 2002). This document discusses various design options for improving the energy efficiency of distribution transformers and describes the reasons for eliminating certain design options from consideration.
- The Department's draft LCC analysis for design line 1 (Distribution Transformer Rulemaking, Life Cycle Cost Analysis, Design Line 1, posted June 6, 2002). This document discusses the methodology and structure of the LCC analysis used for liquid-immersed transformers, along with the basis for various input values and assumptions. It also presents example results from the LCC analysis on a 50 kVA unit.
- The Department's revised engineering analysis for design line 1 (posted June 6, 2002, as Appendix B to the LCC report listed above). This appendix presents a revision of the engineering analysis that the Department originally circulated in December 2001.
- The Department's engineering analysis for medium-voltage dry-type distribution transformers (Distribution Transformer Standards Rulemaking, Draft Report for Review, Engineering Analysis for Dry-type Distribution Transformers and Results on Design Line 9, posted August 23, 2002). This document contains preliminary results of the engineering analysis for design line 9.
- The Department's draft LCC analysis for design line 9 (Distribution Transformer Standards Rulemaking, Draft Report for Review, Dry-type Distribution Transformers, Life Cycle Cost Analysis on Design Line 9, posted October 4, 2002). This document

discusses the methodology and structure of the LCC analysis for dry-type transformers, along with the basis for various input values and assumptions. It also presents sample results from the LCC analysis on a 300 kVA unit.

The Department also posted several spreadsheets while preparing for the ANOPR for early stakeholder review and comment:

- ANOPR engineering analysis results spreadsheets for all 13 design lines (posted April 4, 2003). These spreadsheets summarize the cost and performance of all the designs in the Department's engineering database. One spreadsheet contains the engineering analysis results of the liquid-immersed design lines, and the other contains the dry-type design lines.
- ANOPR LCC spreadsheets for all 13 design lines (posted May 14, 2003). These spreadsheets are used by the Department to calculate the LCC and PBP. The Department conducted a webcast on October 17, 2002, presenting and explaining the basic LCC spreadsheet to stakeholders.

The Department developed two spreadsheet tools for this rulemaking. The first spreadsheet tool calculates LCC and payback periods. Thirteen different LCC and payback period spreadsheets were developed to capture variations in the distribution transformer market. The second spreadsheet tool calculates impacts of candidate standards at various levels on shipments and calculates the NES and NPV at various standard levels. These spreadsheets are posted on the Department's website along with the complete TSD documenting the analyses supporting this ANOPR.

2. Process Improvement

Although the Procedures, Interpretations and Policies for Consideration of New or Revised Energy Conservation Standards for Consumer Products (the ''Process Rule''), 10 CFR Part 430, Subpart C, Appendix A, applies to consumer products, in its Notice of Determination for Distribution Transformers, the Department stated its intent to adhere in this rulemaking to the provisions of the Process Rule, where applicable. 62 FR 54817. In Table I.2, the Department presents the analyses it intends to conduct in its evaluation of standards for distribution transformers.

TABLE I.2.—DISTRIBUTION TRANSFORMERS ANALYSES IN ACCORDANCE WITH THE PROCESS RULE

ANOPR	NOPR	Final rule
Market and technology assessment	Revised ANOPR analyses	Revised analyses.
Screening analysis	Life-cycle cost sub-group analysis	
Engineering analysis	Manufacturer impact analysis	
Energy use and end-use load characterization	Utility impact analysis	
Markups for equipment price determination	Employment impact analysis	
Life-cycle cost and payback period analyses	Environmental assessment	
Shipments analysis	Regulatory impact analysis	
National impact analysis.		

The analyses in Table I.2 reflect methodological improvements made in accordance with the Process Rule, including the development of economic models and analytical tools. For example, this ANOPR uses the full range of consumer marginal energy rates which are the energy rates that correspond to incremental changes in energy use. The LCC analysis also defines a range of energy price forecasts for each fuel used in the economic analyses, and defines a range of primary energy conversion factors and associated emission reductions based on the generation displaced by energy efficiency standards. If timely new data, models, or tools that enhance the development of standards become available, they will be incorporated into this rulemaking.

3. Test Procedure

A test procedure outlines the method by which manufacturers will determine the efficiency of their distribution transformers, and thereby assess compliance with an energy conservation standard. On February 10, 1998, the Department held a workshop on the development of a test procedure for distribution transformers. Representatives from NEMA, manufacturers, utilities, Federal and State agencies, the Canadian government, and other interested parties attended the workshop. The Department presented and discussed draft test procedures based on recognized industry standards. A transcript of the workshop is available at the Building Technologies Program's Resource Room, which is located in Room 1J–018 and is open from 9:00 a.m. to 4:00 p.m., Monday through Friday.

In 1998, NEMA developed and published NEMA Standard TP 2–1998, Standard Test Method for Measuring the Energy Consumption of Distribution Transformers. This publication presents the American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) industry standard test methods for measuring transformer efficiency, and provides a compliance section that describes how manufacturers can demonstrate that their transformers meet the NEMA Standard TP 1 efficiency ratings.

On November 12, 1998, the Department published a Notice of Proposed Rulemaking (NOPR) for a distribution transformer test procedure; the NOPR solicited comments from stakeholders and announced a public workshop. 63 FR 63360. The NOPR proposed that DOE either incorporate parts of the recognized industry testing standards, or simply adopt NEMA Standard TP 2–1998.

The Department held a public workshop on the proposed test procedure rule on January 6, 1999. Based on the comments received and issues raised, the Department concluded that additional analysis was necessary. On June 23, 1999, the Department reopened the comment period on the proposed rule. 64 FR 33431. This second comment period raised issues and solicited comments on the suitability of NEMA Standard TP 2–1998 for use as the DOE test procedure, the definition of a distribution transformer, the sampling plan to demonstrate compliance, and the suitability of the proposed ''basic model'' definition. The Department is issuing a Supplemental Notice of Proposed Rulemaking (SNOPR) for the test procedure, addressing these comments.

While the process of developing and finalizing a test procedure is ongoing, the Department is working to ensure that activities being conducted under the test procedure SNOPR and the standards rulemaking ANOPR are synchronized. For example, some of the comments provided by stakeholders through prior public consultation processes on the test procedure contributed directly to the formulation of the distribution transformer definition proposed in this ANOPR.

II. Distribution Transformer Analyses

This section includes a general introduction to each analysis section and a discussion of relevant issues addressed in comments received from interested parties.

A. Market and Technology Assessment

When the Department begins a standards rulemaking, it develops information on the industry structure and market characteristics of the product concerned. This activity consists of both quantitative and qualitative efforts based primarily on publicly available information. The issues addressed in this market and technology assessment include the product definition, product classes, manufacturers, retail market trends, and regulatory and non-regulatory programs. This information serves as resource material for use throughout the rulemaking.

1. Definition of a Distribution Transformer

Section 346 of EPCA authorizes the Department to consider and determine whether an energy conservation standard for ''distribution transformers'' would be technologically feasible and economically justified, and would result in significant energy savings. (42 U.S.C. 6317(a)(1)) But the statute does not define ''distribution transformer.'' At the framework document workshop, the Department interpreted the term ''distribution transformer'' to mean: ''Transformers designed to continuously transfer electrical energy either single phase or three phase from a primary distribution circuit to a secondary distribution circuit, within a secondary distribution circuit, or to a consumer's service circuit; limited to transformers with primary voltage of 480 V to 35 kV, a secondary voltage of 120 V to 600 V, a frequency of 55–65 Hz, and a capacity of 10 kVA to 2500 kVA for liquid-immersed transformers or 5 kVA to 2500 kVA for dry-type transformers.'' The Department subsequently revised this definition based on input from stakeholders, information on transformers commonly understood to be ''distribution transformers,'' and consideration of whether energy conservation standards for such transformers would result in significant energy savings. The revised proposed definition of a distribution transformer is given in section II.A.1.d.

a. Changes to, and Retention of, Provisions in the Framework Document Definition

The proposed definition of a distribution transformer eliminates the lower limits of 480 V and 120 V, on primary voltage and secondary voltage respectively. In its written comments, NEMA advocated that the Department have no lower limits on the primary and secondary voltages of the transformers it evaluates for standards, reflecting the coverage of NEMA TP 1. (NEMA, No. 7 at p. 4 and No. 19 at p. 2) The American Council for an Energy Efficient Economy (ACEEE) agreed with the Department's working definition presented at the framework document workshop, and commented that the scope should be as broad as possible at this stage of the rulemaking. (ACEEE, No. 14 at p. 1) ACEEE strongly disagreed with a comment made during the framework document workshop recommending that the lower threshold for the primary voltage be raised above 480 V. (Public Hearing Transcript, No. 2MM at pp. 27–28) ACEEE pointed out that the Department's Determination Analysis prepared by ORNL showed substantial energy savings resulted from transformers operating in the low voltage class. (ACEEE, No. 14 at p. 1) Consistent with NEMA and ACEEE's comments, the Department is concerned that defining a distribution transformer as having a minimum primary and/or secondary voltage may result in eliminating certain distribution transformers from consideration in the standards rulemaking. The Department also believes that it can include other elements in its definition of ''distribution transformer'' to ensure that its test procedures and standards for transformers would cover only products that are truly ''distribution transformers.'' Therefore, the Department removed the lower bounds on primary and secondary voltage from the definition of distribution transformer.

With regard to the framework document workshop's capacity criteria for defining a distribution transformer (10 to 2500 kVA for liquid-immersed units and 5 to 2500 kVA for dry-type units), the Department received comment that 5 kVA and 10 kVA single-phase, dry-type units are not normally used for distribution purposes, but rather are almost always used in specialized applications related to the consumption of electricity (*i.e.*, power supplies). (NEMA, No. 7 at p. 4) At the framework document workshop, ABB commented that 5 and 10 kVA dry-type units ''just don't make any sense when somebody considers the concept of distribution.'' (Public Hearing Transcript, No. 2MM at p. 28) To accommodate this input, the Department's revised definition of a distribution transformer proposes a lower capacity limit for dry-type units of 15 kVA, excluding dry-type transformers with ratings of 5 and 10 kVA from the standards rulemaking. The Department seeks comment from other stakeholders on whether such transformers should be classified as distribution transformers, and whether it should adopt a different lower capacity limit for dry-type units in the definition of distribution transformer.

The framework document workshop's definition also included ''[t]ransformers designed to continuously transfer electrical energy either single phase or three phase from a primary distribution circuit to a secondary distribution circuit, within a secondary distribution circuit, or to a consumer's service circuit'' (DOE presentation at Framework Document Workshop, No. 2CC at p. 7) The Department is concerned that these criteria may be too vague and imprecise and subject to misinterpretation, and may fail to establish clearly which transformers are, and which are not, covered under EPCA as distribution transformers. This would particularly affect parties that work with distribution transformers in non-utility applications, where the terminology in these criteria, for example, ''to a consumer's service circuit'' may be inapplicable or meaningless. NEMA advocated that the Department adopt a definition of distribution transformer that aligns with the scope of NEMA TP 1. (NEMA, No. 7 at p. 4) The scope provision of TP 1 states that the standard applies to transformers meeting numerical criteria (*e.g.*, voltage, kVA) and then lists specific types of transformers to which the standard does not apply.

The Department has decided to follow the NEMA TP 1 approach in defining a distribution transformer. In addition to having numerical criteria, DOE's proposed definition lists types of transformers that are made for applications unrelated to the distribution of electricity, or for which standards would not produce significant energy savings, and clarifies that they are not ''distribution transformers'' subject to regulation by the Department. Such a definition is clearer, more precise, and less subject to misinterpretation than the framework document workshop's proposed definition. Although the list of excluded transformers is quite similar to that in NEMA TP 1, DOE has modified it slightly.[1] The Department added definitions for each of these excluded transformers. The Department invites stakeholders to comment on the new distribution transformer definition, the revised scope, the exemptions list, and the exemptions list definitions.

The following transformers were identified in the test procedure NOPR as not being distribution transformers: grounding transformers, machine-tool (control) transformers, regulating transformers, testing transformers, and welding transformers. 63 FR 63370. These transformers are listed as exclusions in the scope provision of NEMA TP 1, and they are not considered in the Department's analysis. Therefore the Department continues to exclude them from its proposed definition of a ''distribution transformer.''

The test procedure NOPR also excluded ''converter and rectifier transformers with more than two windings per phase'' from the definition of distribution transformer and provided definitions for these transformers. 63 FR 63370. Comments submitted to the Department on the test procedure NOPR and the test procedure reopening notice supported these exclusions, as well as the exclusion of rectifier transformers with less than three windings. The Department now believes that the specific exclusion of converter transformers is unnecessary. The definition of distribution transformer includes an upper limit on capacity of 2500 kVA, and it is the Department's understanding that a transformer connected to a converter, *i.e.*, a converter transformer, always has a capacity far above this level. Thus, converter transformers are excluded due to the upper-bound on the kVA range of a distribution transformer. The Department is also proposing to adopt the definition of ''rectifier transformer'' that was recently incorporated into IEEE C57.12.80–2002, Clause 3.379, rather than the definition proposed in the test procedure NOPR. The Department believes the IEEE definition will be more widely understood and accepted, without any loss of technical precision.

b. Exclusions Discussed in the Test Procedure Reopening Notice

The test procedure reopening notice stated that the Department was inclined to exclude autotransformers, and transformers with tap ranges greater than 15 percent, from the definition of distribution transformer. 64 FR 33433–34. The notice identified comments in the test procedure NOPR that advocated these exclusions and the Department's reasons for favoring them. The Department received no comments opposed to these exclusions. Therefore, these exclusions are included in the proposed definition.

The Department also discussed in the test procedure reopening notice whether it should exclude sealed or non-ventilated transformers, special impedance transformers, and harmonic transformers from the definition of distribution transformer. 64 FR 33433–34. Each of these types of transformer could be considered to be a distribution transformer. The Department stated in the reopening notice that it did not find persuasive the reasons commenters had advanced for excluding these products, and that it intended to include them unless it received additional information adequate to justify their exclusion. Concerning non-ventilated or sealed transformers, NEMA commented that the unique features of these transformers could pose a hardship for some manufacturers in testing them, and that they are a small part of the market for distribution transformers. (NEMA, No. 46 at p. 5) Given their small market share, it appears that adopting standards for non-ventilated or sealed transformers would not result in significant energy savings. Thus, DOE is excluding them from the proposed definition of distribution transformer. The Department specifically requests comments, however, on whether such exclusion is warranted.

With respect to special impedance distribution transformers, NEMA stated that they have much higher load losses than standard impedance distribution transformers, and are designed to meet unusual performance functions. (NEMA, No. 46 at p. 5) NEMA also asserted that, because they are relatively expensive to build, a lack of Federal efficiency standards for these products would not cause them to be manufactured and sold in increased volumes as substitutes for standard distribution transformers that were subject to standards. (NEMA, No. 45 at p. 2) The Department agrees with these points. It also believes that the market for these products is very small and that therefore regulating them would not result in significant energy savings. For these reasons, the Department is excluding special impedance transformers from its definition of a distribution transformer.

The Department questions the validity of NEMA's claim that any transformer with an impedance outside the range of four to eight percent is a special impedance transformer. To address this issue, the Department is proposing a definition for ''special impedance transformer'' that incorporates tables which set forth the normal impedance range at each standard kVA rating for liquid-immersed and dry-type transformers. DOE would consider any transformer built with an impedance rating outside the ranges defined as normal is considered special impedance, and is excluded from the definition of distribution transformer. The Department requests comments from stakeholders, particularly manufacturers, on the normal impedance ranges shown in these tables (see Tables II.1 and II.2) of ''special impedance transformers.''

The Department understands that there are two types of harmonic distribution transformers, those that correct harmonics (harmonic mitigating transformers) and those that simply tolerate, and do not correct, harmonics (called harmonic-tolerating or K-factor transformers). Two companies requested that DOE exclude harmonic-mitigating transformers from the standards rulemaking. (MIRUS International, No. 10 at p. 1; Hammond Power Solutions, No. 11 at p. 1) The companies requested the exclusion because these transformers have three or six windings per phase, and the complexity of the windings and the need to limit the temperature rise created by the harmonics when the transformer is in service makes it extremely difficult for them to meet an efficiency standard. The Department agrees with these comments, also noting that harmonic-mitigating transformers are designed for special conditions and provide a unique customer utility. The Department believes few of these transformers exist in the distribution system, regulating them would save little energy, and

[1] The proposed definition of ''distribution transformer'' incorporates almost verbatim 13 of the 17 exclusions set forth in NEMA TP 1. (The list of exclusions from TP 1 appears on page one of the document.) NEMA TP 1, however, also excludes ''transformers designed for high harmonics'' and ''harmonic transformers,'' but today's proposed definition addresses these transformers by excluding ''harmonic mitigating transformers'' and certain ''K-factor'' (harmonic tolerating) transformers. In addition, although TP 1 excludes ''retrofit transformers'' and ''regulation transformers,'' the proposed rule excludes neither—the former for reasons discussed in the ANOPR text and the latter because DOE believe they are more accurately described as ''regulating transformers,'' which are already in the list of exclusions in NEMA TP 1. In addition, NEMA TP 1 excludes ''non-distribution transformers, such as UPS [uninterruptible power supply] transformers.'' Although the proposed definition excludes uninterruptible power supply transformers, the portion of this exclusion referring to ''non-distribution transformers'' is vague and the Department believes its inclusion in the regulations would undercut the precision achieved by listing specific types of transformers as being excluded from the definition of ''distribution transformer.''

excluding them would be unlikely to create loopholes in the regulation. Consequently, the Department is excluding harmonic-mitigating transformers from this rulemaking.

The situation with harmonic tolerating (K-factor) transformers is not so clear cut. These transformers are designed for use in industrial situations where electronic devices can cause transformer losses that are much higher than normal, and they are designed to accommodate such losses without excessive temperature rise. But the Department found that it can be economically viable to use K-factor distribution transformers that have low K-factors and relatively low efficiencies, instead of regular distribution transformers with higher efficiencies in standard applications. For example, as of 1999, Minnesota adopted a building code requirement that all distribution transformers installed in the State meet the NEMA TP 1 efficiency levels, with an exemption for specific transformers excluded from TP 1, including K-factor transformers (see Chapter 3 of TSD). These K–4 transformers had efficiencies that were not only below the levels mandated by NEMA TP 1, they were also below the prevailing efficiency levels of conventional transformers that had been installed in Minnesota before the State's adoption of TP 1. As the K rating of K-factor transformers increases, however, they become increasingly sophisticated and expensive to produce, and their share of the total transformer market diminishes. Thus, the risk that high K-factor rated transformers would be used in place of more efficient transformers declines, and the potential energy savings from regulating them becomes insignificant.

Above the K–4 rating, K–9 and K–13 are the next higher standard K-factor rated transformers. The Department believes that while K–9 products are a small part of the market, it is uncertain whether, absent standards for them, K–9 distribution transformers would replace transformers that are subject to standards (as happened in Minnesota with K–4 transformers). The Department is aware that K-factor transformers at K–13 and higher are significantly more expensive than conventional transformers, and believes it is very unlikely they would be purchased in place of distribution transformers subject to standards. Thus, the Department's proposed definition excludes transformers with a K-factor rating of K–13 or higher, and includes K-factor transformers with lower K-factor ratings (*e.g.*, K–4 and K–9). The Department specifically invites comments on this issue.

Finally, the Department believes that ''retrofit distribution transformer'' could refer to any transformer that replaces an existing distribution transformer. That said, the Department understands that the phrase may refer to a distribution transformer that replaces an existing transformer. This replacement transformer design may specify that the primary and secondary terminals are compatible with existing switchgear, or that the transformer incorporates necessary features or performance characteristics that differ from conventional designs. Comments on the test procedure NOPR asserted that the Department's exclusions from the definition of distribution transformer should provide for situations where existing distribution transformers cannot be replaced with more efficient retrofit transformers, which generally would be larger or configured differently from the existing transformers. In the reopening notice of the test procedure, the Department requested further, more detailed information on this issue. 64 FR 33434. The Department has not received such information. Clearly, retrofit distribution transformers are distribution transformers, but the Department lacks the basis for creating an exclusion for them in the proposed definition. The Department requests stakeholder comment on this issue, specifically information on the nature of and dimensional restrictions for retrofit transformers.

c. Additional Exclusions Drawn From NEMA TP 1

In addition to excluding from the Department's scope the types of transformers discussed in sections II.A.1.a and b of this ANOPR, NEMA TP 1 also excludes drive (isolation), traction-power, and uninterruptible power supply transformers. A drive or isolation transformer is a type of distribution transformer that is specially designed to accommodate added loads of drive-created harmonics and mechanical stresses caused by an alternating current or direct current motor drive. Although intrinsically they have lower efficiencies than conventional distribution transformers, DOE understands that they also have low sales volumes. Therefore, the Department believes that issuing standards for this product would not result in significant energy savings and is proposing to exclude them from the definition of distribution transformer. In addition, the Department notes that there are many kinds of drive transformers, and developing the varied test methods and multiple standard levels necessary to achieve even the limited energy savings possible for this product would be a complex undertaking.

As for traction-power transformers, these are designed to supply power to railway trains or municipal transit systems at frequencies of 16⅔ or 25 Hz in an alternating current circuit or as a rectifier transformer. These transformers are excluded from the proposed definition of distribution transformer by provisions discussed above that exclude both transformers operating at these low frequencies as well as rectifier transformers. Therefore, DOE need not consider additional specific exclusions for these transformers.

Finally, an uninterruptible 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. The uninterruptible power supply transformer is used as part of the electric supply system for sensitive equipment that cannot tolerate system interruptions or distortions, and counteracts such irregularities. Therefore, the Department will exclude uninterruptible power supply transformers from the distribution transformer definition.

d. Distribution Transformer Definition

As noted above, the Department's proposed definition of ''distribution transformer'' is accompanied by specific definitions for each of the transformers excluded from the overall definition. This will clarify which transformers are covered by the standards in this rulemaking. For seven of the transformers excluded from the Department's definition of a distribution transformer, definitions were adapted from IEEE C57.12.80–2002: autotransformers, grounding transformers, machine-tool (control) transformers, non-ventilated transformers, rectifier transformers, regulating transformers, and sealed transformers. For K-factor transformers, the definition is adapted from Underwriters Laboratories (UL) UL1561 and UL1562. The Department developed its own definitions for drive (isolation), the harmonic mitigating, special-impedance, testing, tap ranges greater than 15 percent, uninterruptible power supply and welding transformers based on industry catalogues, practice and nomenclature.

The Department proposes the following definition for a distribution transformer:

Distribution transformer means a transformer with a primary voltage of equal to, or less than, 35 kV; a secondary voltage equal to, or less than, 600 V; a frequency of 55–65 Hz; and a capacity of 10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units, and does not include the following types of transformers: (1) Autotransformer; (2) drive (isolation) transformer; (3) grounding transformer; (4) harmonic mitigating transformer; (5) K-factor transformer; (6) machine-tool (control) transformer; (7) non-ventilated transformer; (8) rectifier transformer; (9) regulating transformer; (10) sealed transformer; (11) special-impedance transformer; (12) testing transformer; (13) transformer with tap range greater than 15 percent; (14) uninterruptible power supply transformer; or (15) welding transformer.

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

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

Grounding transformer means a three-phase transformer intended primarily to provide a neutral point for system-grounding purposes, either by means of: (a) A grounded wye primary winding and a delta secondary winding; or (b) an autotransformer with a zig-zag winding arrangement.

Harmonic mitigating transformer means a transformer designed to cancel or reduce the harmonics drawn by computer equipment and other non-linear power electronic loads.

K-factor transformer means a transformer with a K-factor of 13 or greater that is designed to tolerate the additional eddy-current losses resulting from harmonics drawn by non-linear loads, usually when the ratio of the non-linear load to the linear load is greater than 50 percent.

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

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

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

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

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

Special-impedance transformer means any transformer built to operate at an impedance outside of the normal impedance range for that transformer's kVA rating. The normal impedance range for each kVA rating is shown in Tables II.1 and II.2:

TABLE II.1.—NORMAL IMPEDANCE RANGES FOR LIQUID-IMMERSED TRANSFORMERS

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

TABLE II.2.—NORMAL IMPEDANCE RANGES FOR DRY-TYPE TRANSFORMERS

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

Testing Transformer means a transformer used in a circuit to produce a specific voltage or current for the purpose of testing electrical equipment. This type of transformer is also commonly known as an instrument transformer.

Transformer with Tap Range greater than 15 percent means a transformer with a tap range in the primary winding greater than the range accomplished with six 2.5-percent taps, 3 above and 3 below the rated primary voltage (*e.g.*, 6 times 2.5 percent = 15 percent).

Uninterruptible Power Supply Transformer means a transformer that supplies power to 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.

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

e. Exclusions Not Incorporated

Howard Industries, Edison Electric Institute (EEI), Southern Company, and TXU Electric and Gas all submitted comments requesting that liquid-filled transformers be excluded from the rulemaking. (Howard Industries, No. 4 at p. 2; EEI, No. 6 at p. 1; Southern Company, No. 8 at p. 5; TXU Electric and Gas, No. 12 at p. 1) One reason cited for EEI's request is the fact that in a deregulated electricity market, the energy saving benefits will accrue to the energy service provider, while the additional capital equipment cost will be borne by the utility distribution company. (EEI, No. 6 at pp. 2–3) Southern Company requested that liquid-immersed transformers be excluded from the rulemaking because the energy savings potential is only one-quarter the total energy savings estimate in the Determination Analysis, and because many utilities choose to buy transformers below TP 1 levels for their own economic reasons. (Southern Company, No. 8 at p. 5)

The Natural Resources Defense Council (NRDC) countered these requests in their comments, noting that at the framework document workshop, several commenters identified a trend stemming from restructuring in the electric utility industry, which is causing fewer and fewer electricity providers to use a lowest TOC method for purchasing transformers, thereby causing liquid-immersed transformer efficiencies to decline. NRDC sees this trend as a market failure that requires Federal standards to correct the problem. (NRDC, No. 5 at p. 4) NRDC urged DOE to consider the widest possible scope for transformer efficiency standards in doing its analysis. (NRDC, No. 5 at p. 6)

At this time, the Department is not excluding liquid-immersed transformers from the scope of the rulemaking. The Department is charged with determining whether standards for distribution transformers are technologically feasible and economically justified and would result in significant energy savings. No one has argued that liquid-immersed transformers are not distribution transformers, and therefore that they fall outside the scope of the Department's statutory authority. Furthermore, DOE is not able to conclude, based on the data and information available to it, that standards for liquid-immersed transformers are not technologically feasible nor economically justified, or that standards for this equipment would not result in significant energy savings. Thus, the Department will be investigating whether the inclusion of liquid-immersed standards is warranted.

2. Product Classes

In general, when evaluating and establishing energy efficiency standards, the Department divides covered products into classes by: (a) the type of energy used; (b) capacity; and (c) performance-related features that affect consumer utility or efficiency. Different energy efficiency standards may apply to different product classes. The Department has received some guidance from stakeholders on establishing appropriate product classes for the population of distribution transformers.

Howard Industries stated that liquid-immersed distribution transformers should not be categorized with dry-type distribution transformers. (Howard Industries, No. 4 at p. 2) Cooper Power Systems believes that the Department should set one standard for all distribution transformers and not treat liquid-immersed and dry-type transformers separately. (Cooper Power Systems, No. 34 at p. 1) The Department recognizes that liquid-immersed and dry-type units have different physical construction and different end-use applications. Generally, liquid-immersed units are filled with mineral oil and are used in outdoor installations (*e.g.*, concrete pad or pole-mounted). The Department recognizes that dry-type units are generally used for indoor applications and must comply with the safety requirements of the National Electrical Code (ANSI/National Fire Protection Association Standard 70). Due to these differences in performance-related features that affect consumer utility, the Department is tentatively planning to have separate efficiency standards for liquid-immersed and dry-type distribution transformers, and to treat them as two distinct product classes.

NEMA recommended that the Department use the product classes given in TP 1, which are based on the type of transformer (liquid or dry), the number of phases (1 or 3), voltage (low or medium) and the kVA rating. (NEMA, No. 7 at p. 5) ACEEE supported the Department's use of the product classes in TP 1, since this standard is now extensively used by manufacturers, the ENERGY STAR'' program administered by DOE and the Environmental Protection Agency (EPA), and voluntary programs operated by utilities and other organizations in association with the Consortium for Energy Efficiency's transformer initiative. (ACEEE, No. 14 at p. 2) The Department agrees with these comments and intends to use NEMA TP 1 product classes for all transformers except medium-voltage, dry-type units.

NEMA noted in a comment that medium-voltage, dry-type transformers may be separated into two groups, based on their Basic Impulse Insulation Level (BIL). (NEMA, No. 7 at p. 6) At that time, NEMA indicated it was considering revising TP 1–1996 and splitting the standard levels for medium-voltage, dry-types into two groups. NEMA later confirmed that it did adopt this modification for TP 1–2002, establishing one standard for medium-voltage, dry-types less than or equal to 60 kV BIL and a separate standard for those units greater than 60 kV BIL. (NEMA, No. 26 at p. 1)

The Department understands that the reason for this revision to TP 1 is that the efficiency of a dry-type, medium-voltage transformer varies in part due to the level of insulation in its windings (the BIL rating). If one efficiency level were assigned to all BIL levels, it would be a relatively weak standard for low BIL ratings and an extremely difficult standard for higher BIL ratings. Implementing one standard across all dry-type, medium-voltage BIL ratings could result in driving the market toward a BIL rating lower than it would otherwise be in the absence of a standard.

However, at this time, the Department is concerned that simply using two BIL groupings as used in TP 1–2002 (<60 kV BIL and >60 kV BIL) may not result in appropriate efficiency levels for all types of medium-voltage, dry-type transformers. Thus, for the ANOPR, the Department based its analysis on a slightly finer resolution of BIL levels and created three classifications: 20–45 kV BIL, 46–95 kV BIL, and >96 kV BIL. In this way, candidate standard levels will be more accurately suited to the covered transformers. The Department requests comments from stakeholders on this decision to create three BIL classifications rather than the two in NEMA's TP 1–2002.

TXU Electric and Gas recommended that the Department separate liquid-immersed and dry-type distribution transformers, and then further separate liquid-immersed transformers into commercial and industrial end users, and residential end users. (TXU Electric and Gas, No. 12 at p. 5) TXU Electric and Gas made this recommendation because it believes the loading profiles of a transformer supplying a residential load versus one supplying a commercial or an industrial load could be dramatically different. The Department cannot accommodate this request as standards cannot be promulgated separately based on the particular uses made by individual users. However, the Department does address sectoral (end-user) issues such as load profiles and energy prices in the LCC analysis (see Chapter 8 of the TSD).

Table II.3 presents the Department's proposed product classes.

TABLE II.3.—PROPOSED DISTRIBUTION TRANSFORMER PRODUCT CLASSES

Number	Insulation	Voltage	Phases	BIL rating	kVA range
1	Liquid-Immersed.	Medium	Single		10–833 kVA
2	Liquid-Immersed.	Medium	Three		15–2500 kVA
3	Dry-Type	Low	Single		15–333 kVA
4	Dry-Type	Low	Three		15–1000 kVA
5	Dry-Type	Medium	Single	20–45kV BIL	15–833 kVA
6	Dry-Type	Medium	Three	20–45kV BIL	15–2500 kVA
7	Dry-Type	Medium	Single	46–95kV BIL	15–833 kVA
8	Dry-Type	Medium	Three	46–95kV BIL	15–2500 kVA
9	Dry-Type	Medium	Single	≥96kV BIL	75–833 kVA
10	Dry-Type	Medium	Three	≥96kV BIL	225–2500 kVA

3. Market Assessment

The liquid-immersed transformer market accounted for 77 percent of the distribution transformers sold in the United States in 2001 (on a unit basis). These transformers accounted for 74 percent of the distribution transformer capacity measured in megavolt-amperes (MVA), and 78 percent of the dollar value of the 2001 shipments. On a unit basis, more than 90 percent of the liquid-immersed shipments are single-phase units. However, these single-phase units tend to have lower kVA ratings than the three-phase units, which are more than half of the total MVA capacity shipped of liquid-immersed distribution transformers in 2001.

In the dry-type market, low-voltage, three-phase distribution transformers dominate, accounting for 91 percent of units and 78 percent of MVA shipped. Medium-voltage, three-phase units accounted for only one percent of the units shipped, but were 18 percent of MVA shipments in 2001. The low-voltage, single-phase units were about 7 percent of the dry-type units shipped; however, because their kVA ratings tend to be small, they only accounted for about 3.5 percent of the cumulative dry-type MVA shipments in 2001. Medium-voltage, single-phase units occupy a small part of the market, representing less than one-half of one percent of both units and MVA shipped. A detailed estimate of total national shipments of distribution transformers for 2001 can be found in the shipments analysis, section II.G and in Chapter 9 of the TSD.

Market characteristics related to efficiency trends indicate that distribution transformer efficiencies are decreasing. ORNL identified this trend for dry-type transformers in its Determination Analysis, noting that over the last two decades, efficiency of dry-type units has declined. ORNL indicated that part of the reason for this trend was a focus on lowest first-cost units, because contractors purchasing the units would not benefit directly from the energy savings. For liquid-immersed distribution transformers, NEMA commented that a few years ago nearly 100 percent of utility transformers sold met or exceeded the TP 1 efficiency standard. NEMA estimates that in the liquid-immersed market, the percentage of TP 1 compliant units in 2002 dropped to about 50 percent. (NEMA, No. 26 at p. 3) NEMA's comment is consistent with comments made at the framework document workshop by TXU Electric and Gas and Southern Company that deregulation of electric utilities is shifting the liquid-immersed market toward less efficient, lower first-cost distribution transformers. (Public Hearing Transcript, No. 2MM at pp. 66–69) The Department is concerned that the liquid-immersed market may be following the dry-type market, moving toward less energy efficient units.

4. Technology Assessment

The technology assessment provides the technical background and structure on which the engineering analysis is based. The Department based its list of technologically feasible design options on input from manufacturers, component suppliers, trade publications, and technical papers. The technology assessment for this rulemaking incorporates input from eight manufacturers and one component supplier visited by the Department, as well as written comments.

Table II.4 is adapted from the ORNL study, Determination Analysis of Energy Conservation Standards for Distribution Transformers, ORNL–6847, 1996. This table summarizes the methods of making a transformer more efficient by reducing the number of watts lost in the core (no-load) and winding (load), and the associated inter-relational issues. The engineering analysis examined the options shown in this table (see Chapter 5 of the TSD).

Nearly all the energy consumed by distribution transformers is lost in the core and the winding assemblies. Design modifications that reduce losses in the core may cause an increase in winding losses; conversely, modifications to the design that reduce losses in the windings may increase losses in the core.

TABLE II.4.—OPTIONS AND IMPACTS OF INCREASING TRANSFORMER EFFICIENCY

	No-load losses	Load losses	Cost impact
To decrease no-load losses			
Use lower-loss core materials	Lower	No change*	Higher.
Decrease flux density by:			
(a) Increasing core cross-sectional area (CSA)	Lower	Higher	Higher.
(b) Decreasing volts per turn	Lower	Higher	Higher.
Decrease flux path length by decreasing conductor CSA.	Lower	Higher	Lower.

TABLE II.4.—OPTIONS AND IMPACTS OF INCREASING TRANSFORMER EFFICIENCY—Continued

	No-load losses	Load losses	Cost impact
To decrease load losses			
Use lower-loss conductor material	No change	Lower	Higher.
Decrease current density by increasing conductor CSA	Higher	Lower	Higher.
Decrease current path length by:			
(a) Decreasing core CSA	Higher	Lower	Lower.
(b) Increasing volts per turn	Higher	Lower	Lower.

*Amorphous-core materials would result in higher load losses.

B. Screening Analysis

The purpose of the screening analysis is to identify design options that improve distribution transformer efficiency and to determine which options to evaluate and which options to screen out. The Department consults with industry, technical experts, and other interested parties in developing a list of design options for consideration. It then applies the following set of screening criteria to determine which design options are unsuitable for further consideration in the rulemaking (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 of 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; and

(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.

By applying these screening criteria to a comprehensive list of design options, the Department developed the following list of efficiency-related enhancements to examine in the engineering analysis:

- Differing conductor coil materials: aluminum and copper in wire and foil configurations;
- Differing core materials: cold-rolled, high-silicon (CRHiSi) steel; CRHiSi domain-refined steels; and amorphous materials in wound core;
- Varying design dimensions: flux density (B); current density (J); volts/turn; voltage spacings; frame/coil dimensions; shape; cooling channels (number and location); insulating materials; and shell or core form, stacked or wound; and
- Using different construction techniques: core cutting; core stacking; core lapping or butting of joints; coil winding; and low voltage-high voltage winding pattern.

The Department is not considering the following design options because they do not meet one or more of the aforementioned four screening criteria: Silver as a conductor material; high-temperature superconductors; amorphous core material in stacked core configuration; carbon composite materials for heat removal; high-temperature insulating material; and solid-state (power electronics) technology. Discussion of the application of the screening criteria to these design options appears in Chapter 4 of the TSD.

The Department received stakeholder comments relating to the screening analysis during and after the Distribution Transformer Framework Workshop, November 1, 2000. One issue raised by ABB during the workshop related to screening out sole-source technology. The Department responded by stating that it would not set a standard that required sole-source technology for compliance. (Public Hearing Transcript, No. 2MM at pp. 96–98) ABB also commented that an ''off-the-wall'' technology (*e.g.*, superconductors) should be screened out. NRDC responded to ABB by observing that technologies often are more realistic than they initially appear. (Public Hearing Transcript, No. 2MM at pp. 98–104) However, upon further analysis and consultation with experts (see Chapter 4 of the TSD), the Department made the decision to screen out superconducting materials.

In its written comments submitted to the Department for the framework document, NEMA commented that superconducting winding and power electronics should be screened out. (NEMA, No. 7 at p. 7) The Department considered these as it analyzed all the design options available to make transformers more efficient, and agreed that both superconducting material and solid-state (power electronics) should be screened out.

C. Engineering Analysis

The purpose of the engineering analysis is to evaluate a range of transformer efficiency levels and associated manufacturing costs. The engineering analysis considers technologies and design option combinations not eliminated in the screening analysis. The LCC analysis uses the cost-efficiency relationships developed in the engineering analysis.

The Department typically structures its engineering analysis around one of three methodologies. These are: (1) The design-option approach, calculating the incremental costs of adding specific design options to a baseline model; (2) the efficiency-level approach, calculating the relative costs of achieving energy efficiency improvements; and/or (3) the reverse-engineering or cost-assessment approach, which involves a ''bottoms-up'' manufacturing cost assessment based on a detailed bill of materials derived from transformer tear-downs. At the framework document workshop, the Department solicited comments to determine which would be the best approach to follow in the engineering analysis.

1. Approach Taken in the Engineering Analysis

There was no clear consensus among the respondents at the November 2000 framework document workshop regarding the most appropriate approach to pursue in the engineering analysis. NEMA believes that the efficiency-level approach is by far the superior method, noting that both the design-option and cost-assessment approaches require the estimation of manufacturing costs by people who are not experts in the art and science of transformer design and manufacturing. NEMA recommended the efficiency-level approach, where manufacturers provide data on the relationship between cost and efficiency. (NEMA, No. 7 at p. 8) TXU Electric and Gas agreed with NEMA that the efficiency-level approach would be the most appropriate for this product. (TXU Electric and Gas, No. 12 at p. 6)

ACEEE recommended that the Department follow the cost assessment approach, as it has proven more accurate and reliable in prior rulemakings. (ACEEE, No. 14 at p. 3) However, the Department did not consider this recommendation feasible, as the cost assessment approach would require purchasing large quantities of distribution transformers, disassembling them, and determining the additional cost involved in making one design more efficient than another. As the energy efficiency of a transformer is linked to its core dimensions, number of turns, and other design modifications, including alternative core steels or winding materials, this approach would be extremely expensive and difficult to implement, while maintaining sufficient levels of accuracy.

While studying the various approaches and respondents' comments relating to the engineering analysis, the Department learned that the transformer manufacturing industry commonly uses computer software to design a distribution transformer to fill a customer's order. The software-design approach is founded on market dynamics, described in Chapter 3 of the TSD, where customers issue performance characteristics in a contract tender and manufacturers compete for the award based on designs they generate using their computer software and current material costs. The Department used transformer design software to create a database of distribution transformer designs spanning a range of efficiencies, while tracking all the modifications to the core, coil, labor, and other key cost components. This method is referred to as the ''modified design-option approach'' because the design software calculates the incremental costs of improving or changing a design or changing the combination of materials to improve the efficiency. The Department selected software developed by an independent company not associated with any one manufacturer or manufacturer's association. This company, OPS, conducted the design runs spanning a range of efficiencies for the Department's engineering analysis.

The Department published a draft engineering analysis update report in December 2001, incorporating the initial design runs from OPS on one of the representative units. The Department received comments from manufacturers, consultants, and other stakeholders suggesting revisions to the software input parameters and assumptions. The losses reported for the evaluated designs were found to be too high, particularly in comparison to other publicly available data as found in the ORNL Determination Analysis report or an ENERGY STAR® / NEMA TP 1 unit. (AK Steel, No. 18 at pp. 1–2) Similarly, core destruction factors were high, in the range of 12 to 20 percent. (AK Steel, No. 18 at p. 2) The Department discussed these comments with OPS, and made modifications to the software inputs to correct for the high losses and destruction factor. AK Steel also suggested that OPS review its core lamination factors, which appeared to be low and somewhat inconsistent. (AK Steel, No. 18 at p. 3) The Department consulted with OPS and adjusted the lamination factors to make them consistent and bring them more in line with industry factors. NEMA commented that its members would comment directly on the draft analysis when they hosted plant visits from the Department in early 2002. (NEMA, No. 19 at p. 2) At these meetings, manufacturers made recommendations to the Department to fine-tune the OPS software and adjust some of the material prices and markups. In total, the Department met with eight transformer manufacturers and one component supplier in early 2002, not all of which are NEMA members.[2] The Department worked with OPS to incorporate these revisions to the software inputs before conducting the ANOPR computer design runs.

The Department published revised, draft liquid-immersed engineering analysis results on June 5, 2002, as an appendix to the report Distribution Transformer Rulemaking—Life-Cycle Cost Analysis, Design Line 1. AK Steel submitted comments on the revised draft engineering analysis, indicating that the temperature rise in all three example designs included in the appendix were reported to be 55°C rather than the expected 65°C. (AK Steel, No. 36 at p. 1) The Department investigated this problem and learned that the temperature rise reported in the documentation was not the temperature rise used in the software design program. The designs were created using a 20°C ambient and 65°C temperature rise; however, when the design specification report was created, a 30°C ambient temperature had been mistakenly entered, which forced the reported temperature rise to be 55°C. Thus, the design was created with a 65°C rise, but inadvertently reported as 55°C. This typographical error was confirmed upon careful review of the design reports and documentation produced for the appendix of the draft report.

The Department also published a draft engineering analysis, Distribution Transformer Standards Rulemaking, Draft Report for Review, Engineering Analysis for Dry-type Distribution Transformers and Results on Design Line 9, on August 23, 2002, which provided preliminary results on one of the dry-type representative units. An AK Steel comment on the designs presented in this report noted a typographical error concerning a parenthetical description of H–0 core steel as a laser-scribed M3, when in fact H–0 is a 9-mil high permeability grain-oriented steel produced in a laser-scribed condition. (AK Steel, No. 29 at p. 1) AK Steel also found that the core destruction factors were high for these designs, ranging between 24 percent and 38 percent. (AK Steel, No. 29 at p. 2) The Department discussed this with OPS, and modified the software inputs to reduce the core destruction factors. AK Steel also noted that the core stacking rate used in the designs was four inches per hour, and showed that the rate should not be constant, but should vary with the thickness of the core steel. (AK Steel, No. 29 at p. 1) The Department acknowledges that this is a simplification in the engineering analysis of dry-type distribution transformers that was implemented after discussing with OPS the labor estimate part of the manufacturing cost. However, labor assembly times vary widely across all the dry-type manufacturing companies in the United States (due to differing levels of

[2] During the first quarter of 2002, the Department met with eight distribution transformer manufacturers, including ABB Power Technology Products Division USA (both a liquid-immersed plant and a dry-type plant), Acme Electric Corporation, Cooper Power Industries, Federal Pacific Transformer Company, Howard Industries Inc., Jefferson Electric Inc., Kuhlman Electric Corporation, and Square-D Company. The Department also met with AK Steel, a core steel manufacturer. Together, representatives of these nine companies contributed more than 60 hours of presentations, interviews, and plant tours to the Department's engineering analysis.

automation). By using one value for the core stacking rate, the Department approximates what the labor costs are for an average transformer company rather than any one in particular. The Department invites further comments on the issue of stacking rates and use of differential times for varying thicknesses of core steels.

2. Simplifying the Analysis

NEMA has 99 different efficiency levels in its TP 1–2002 document, covering both liquid-immersed and dry-type distribution transformers, single- and three-phase ratings, and spanning the kVA ranges and insulation levels.

NEMA commented that there are too many classes on which to conduct detailed analyses, and the Department should select a limited number of representative units for detailed analysis. (NEMA, No. 7 at p. 5) The Department agrees that it would be impractical to conduct a detailed analysis of the cost-efficiency relationships on each kVA rating of distribution transformers, and worked to develop an approach that would simplify the analysis while keeping a sufficient degree of technical accuracy. The Department consulted with industry representatives and transformer design engineers, and developed an understanding of the construction techniques typically employed in the transformer manufacturing industry. It found that many of the kVA ratings share similar design and construction principles, such that within a given product class of transformers (as defined in section II.A.2), some units would have similar methods of construction.

Building on this understanding, the Department drafted and proposed ‘‘engineering design lines,’’ grouping together certain kVA ratings within sub-divisions of the proposed product classes. These proposed engineering design lines published in the December 2001 draft report were in response to a request from ACEEE asking the Department to prepare and publish preliminary analyses as soon as possible to allow stakeholders to review and comment on the rulemaking process. (ACEEE, No. 14 at p. 3) Based on stakeholder feedback and the meetings held with the manufacturers in early 2002, the Department arrived at a final set of thirteen engineering design lines that group together kVA ratings within product classes, thereby covering all the kVA ratings shown in TP 1.

Table II.5 illustrates the relationship between the proposed product classes and the engineering design lines. Several of the product classes are sub-divided into two or more engineering design lines, enabling the Department to have more accurate results when studying the cost-efficiency relationship. None of the engineering design lines span across two product classes. However, three of the product classes (numbers 5, 7 and 9, all dry-type, medium-voltage, single-phase) have such low shipment volume that the Department decided to scale analysis results from the three-phase, medium-voltage, dry-type units to cover these product classes. This scaling operation involves simply dividing the analysis findings by three.

TABLE II.5.—MAPPING OF PROPOSED PRODUCT CLASSES TO ENGINEERING DESIGN LINES

Distribution transformer product class	kVA range	Engineering design lines
1. Liquid-immersed, medium-voltage, single-phase	10–833	DL 1: 10–100 kVA, Rectangular DL 2: 10–100 kVA, Round DL 3: 167–833 kVA
2. Liquid-immersed, medium-voltage, three-phase	15–2500	DL 4: 15–500 kVA DL 5: 750–2500 kVA
3. Dry-type, low-voltage, single-phase	15–333	DL 6: 15–333 kVA
4. Dry-type, low-voltage, three phase	15–1000	DL 7: 15–150 kVA DL 8: 225–1000 kVA
5. Dry-type, medium-voltage, single-phase, 20–45 kV BIL	15–833	(DL 9/3: 15–167 kVA)* (DL 10/3: 250–833 kVA)*
6. Dry-type, medium-voltage, three-phase, 20–45 kV BIL	15–2500	DL 9: 15–500 kVA DL 10: 750–2500 kVA
7. Dry-type, medium-voltage, single-phase, 46–95 kV BIL	15–833	(DL 11/3: 15–167 kVA)* (DL 12/3: 250–833 kVA)*
8. Dry-type, medium-voltage, three-phase, 46–95 kV BIL	15–2500	DL 11: 15–500 kVA DL 12: 750–2500 kVA
9. Dry-type, medium-voltage, single-phase, ≥96 kV BIL	75–833	(DL 13/3: 75–833 kVA)*
10. Dry-type, medium-voltage, three-phase, ≥96 kV BIL	225–2500	DL 13: 225–2500 kVA

*Due to the low shipment volume in these three product classes, the Department decided to scale the results of analysis on the three-phase medium-voltage (MV) dry-type distribution transformers to these single-phase units, by dividing the results of the three-phase analysis by three to adjust to single-phase.

From each of the thirteen engineering design lines, the Department selected one representative unit to study in detail in both the engineering and the LCC analysis. Once these two analyses were complete, the Department scaled the findings on these units to all the other kVA ratings within each of the thirteen design lines using the 0.75 scaling rule (see Chapter 5 in the TSD). This rule states that for similarly designed transformers, construction costs and watt losses scale to the ratio of kVA ratings raised to the 0.75 power. Square D informed DOE of this fact during a public hearing about the Department's test procedure rulemaking held on January 6, 1999. Square D stated that the material content, as well as the losses, scale to the three-quarter power of kVA. (Public Hearing Transcript, No. 47 at p. 158)

The selection of the thirteen representative units was based on inputs from multiple sources. For example, NEMA suggested that six kVA ratings should form the nucleus of the representative units for further analysis. (NEMA, No. 7 at p. 5) Of these, the Department selected four units for its engineering analysis: a liquid-filled, 50 kVA, single-phase, pad-mounted transformer was used for design line 1; a liquid-filled, 25 kVA, single-phase, pole-mounted transformer was used for design line 2; a dry-type, 75 kVA, low-voltage, three-phase transformer was used for design line 7; and a dry-type, 2000 kVA, medium-voltage, three-phase transformer was used for design line 13. The two other recommended ratings (500 kVA and 2000 kVA three-phase, liquid-immersed transformers) did not fit well with the structure of the design lines. The Department did not select the liquid-filled, 500 kVA, three-phase, pad-mounted transformer because liquid-filled, three-phase units span two design lines, ranging from 15 to 500 kVA (design line 4), and from 750 to 2500 kVA (design line 5). To keep any scaling error to a minimum, the Department selected representative units from around the middle of the kVA ranges of each engineering design line. The Department's decision to split the three-phase, liquid-immersed units into two separate design lines came after input was received from manufacturers during the 2002 site visits and analysis by the Department's technical team. Thus, a 150 kVA, three-phase, liquid-immersed unit was selected for design line 4 instead of the NEMA-recommended 500 kVA unit. Similarly, a 1500 kVA, three-phase, liquid-immersed transformer was selected instead of the NEMA-recommended 2000 kVA transformer for design line 5.

For the dry-type distribution transformer design lines, the representative units were selected following meetings held with manufacturers in early 2002. Manufacturers recommended the ratings chosen because they were either the mid-point of a design line's kVA range (minimizing any scaling error introduced by the 0.75 scaling rule) or the selected rating represented a high volume kVA rating. Following the demarcation of the product classes (see Table II.3), dry-type distribution transformers constitute eight engineering design lines, grouped by kVA and BIL rating. As discussed in section II.A.2 on product classes, the Department learned that using different BIL ratings would be necessary to capture the important differences in the cost-efficiency relationships between units. If a single efficiency standard were set across all medium-voltage, dry-type BIL ratings, it would be a comparatively weak standard for lower BIL ratings and a difficult (if not impossible) standard for a higher BIL rating. NEMA recognized this problem in its TP 1–1996 document; when it published the revised TP 1 in 2002, it divided medium-voltage, dry-types into two groups: ≤60 kV BIL and >60 kV BIL. Based on comments the Department received during its manufacturer site visits in early 2002, the Department elected to use three BIL groups for the ANOPR: ≤45 kV BIL, 46–95 kV BIL and ≥96 kV BIL. This additional disaggregation enables the Department to propose more accurate efficiency standards for the appropriate BIL rating, thereby reducing the possibility of ineffectual standards on lower BIL ratings or excessive standards on higher BIL ratings. The Department invites comment from stakeholders on this decision to have more dry-type BIL categories than NEMA's TP 1–2002.

Manufacturers also informed the Department during their meetings that differences in BIL ratings are only important for medium-voltage, dry-type distribution transformers. Separate standards by BIL rating are not required for the liquid-immersed or the low-voltage, dry-type units.

Once DOE became aware of the importance of BIL ratings for medium-voltage, dry-type distribution transformers, it selected some representative units for design lines 9 through 13 with BIL ratings slightly higher than conventional levels for the specified primary voltages. The Department made these selections after discussions with several manufacturers, to ensure that efficiency standards would not excessively penalize customers purchasing transformers built with primaries operating at higher-than-normal BIL levels. For example, the representative unit from design line 9 is a 300 kVA, three-phase, dry-type transformer with a 4160 V primary voltage. This primary voltage would normally be built with a 30 kV BIL; however, for a particular application there could be exposure to higher than normal voltage surges resulting from switchgear, and transformer specifiers may choose to order this unit with a 45 kV or even a 60 kV BIL. If the Department established the minimum efficiency standard based on a 30 kV BIL, it could restrict the manufacturer's ability to manufacture a compliant 45 kV BIL or 60 kV BIL unit. To accommodate this concern of manufacturers, the Department selected slightly higher than normal BIL ratings for each of the representative units in design line 9 through 13 for the specified primary voltages.

Table II.6 presents the Department's thirteen engineering design lines and the representative units selected from each design line for analysis. Note that for the liquid-immersed, medium-voltage, single-phase distribution transformers, design line 1 represents rectangular tank units from 10 to 100 kVA while design line 2 covers the same kVA range, but represents cylindrical tank designs. The Department analyzed these two common methods of manufacturing this type of transformer to capture any economic variability that may result from different core/coil construction techniques or tank costs.

TABLE II.6.—ENGINEERING DESIGN LINES AND REPRESENTATIVE UNITS FOR ANALYSIS

DL	Type of distribution transformer	kVA range	Voltage taps	Secondary voltages	Engineering design line representative unit
1	Liquid-immersed, medium-voltage, single-phase, rectangular tank.	10–100	±2–2.5%	240/120 to 600V	50kVA, 65°C, single-phase, 60Hz, 7200V primary, 240/120V secondary, rectangular tank
2	Liquid-immersed, medium-voltage, single-phase, round tank.	10–100	±2–2.5%	120/240 to 600V	25kVA, 65°C, single-phase, 60Hz, 24940GrdY/14400V primary, 120/240V secondary, round tank
3	Liquid-immersed, medium-voltage, single-phase.	167–833	±2–2.5%	120/240 to 600 V	500kVA, 65°C, single-phase, 60Hz, 14400/24940YV primary, 277/480YV secondary
4	Liquid-immersed, medium-voltage, three-phase.	15–500	±2–2.5%	208Y/120 to 600V	150kVA, 65°C, three-phase, 60Hz, 12470Y/7200V primary, 208Y/120V secondary
5	Liquid-immersed, medium-voltage, three-phase.	750–2500	±2–2.5%	208Y/120 to 600Y/347V.	1500kVA, 65°C, three-phase, 60Hz, 24940GrdY/14400V primary, 480Y/277V secondary
6	Dry-type, low-voltage, single-phase	15-333	Universal*	120/240 to 600V	25kVA, 150°C, single-phase, 60Hz, 480V primary, 120/240V secondary, 10kV BIL

TABLE II.6.—ENGINEERING DESIGN LINES AND REPRESENTATIVE UNITS FOR ANALYSIS—Continued

DL	Type of distribution transformer	kVA range	Voltage taps	Secondary voltages	Engineering design line representative unit
7	Dry-type, low-voltage, three-phase	15-150	Universal*	208Y/120 to 600Y/347V.	75kVA, 150°C, three-phase, 60Hz, 480V primary, 208Y/120V secondary, 10kV BIL
8	Dry-type, low-voltage, three-phase	225-1000	Universal*	208Y/120 to 600Y/347V.	300kVA, 150°C, three-phase, 60Hz, 480V Delta primary, 208Y/120V secondary, 10kV BIL
9	Dry-type, medium-voltage, three-phase, 20–45kV BIL.	15-500	±2–2.5%	208Y/120 to 600Y/347V.	300kVA, 150°C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
10	Dry-type, medium-voltage, three-phase, 20–45kV BIL.	750–2500	±2–2.5%	208Y/120 to 600Y/347V.	1500kVA, 150°C, three-phase, 60Hz, 4160V primary, 480Y/277V secondary, 45kV BIL
11	Dry-type, medium-voltage, three-phase, 20–45kV BIL.	15–500	±2–2.5%	208Y/120 to 600Y/347V.	300kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
12	Dry-type, medium-voltage, three-phase, 60–95kV BIL.	750–2500	±2–2.5%	208Y/120 to 600Y/347V.	1500kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 95kV BIL
13	Dry-type, medium-voltage, three-phase, 110–150kV BIL.	225–2500	±2–2.5%	208Y/120 to 600Y/347V.	2000kVA, 150°C, three-phase, 60Hz, 12470V primary, 480Y/277V secondary, 125kV BIL

*Universal Taps are 2 above and 4 below 2.5%.

3. Developing the Engineering Analysis Inputs

The Department conducted a modified design-option approach, where a third party creates a database of viable transformer designs and estimates their cost and performance characteristics. The Department selected the software design company OPS to prepare this database. OPS has been providing transformer design services for various manufacturers in the U.S. and abroad for more than 30 years.

The Department worked closely with the nine manufacturers it visited in early 2002 to develop and refine the software inputs for the representative units. The inputs required for the analysis included both design-related inputs (*e.g.*, types of core steel, windings, core configurations, insulation, and spacers) and the cost of these materials and labor. Using these inputs, OPS created a design database that spans the range of efficiency levels for each of the distribution transformers studied in the engineering analysis. This range of efficiency levels spans from the lowest first-cost units to the maximum, technologically feasible efficiency level.

Information concerning the design inputs for the representative units from each of the engineering design lines appears in Chapter 5 of the TSD. The information provided includes the minimum performance characteristics, the core-coil combinations, primary and secondary voltages, voltage taps, and other design details. Chapter 5 of the TSD also provides the material costs used for core steel, wire and strip windings, insulation, spacers, bushings, tanks, core clamps, hardware, and all the other components costed in the OPS generated transformer designs.

These material costs are critical inputs to the OPS design software. To be consistent with industry practice, OPS marks up the raw material prices entered into the software. In other words, the scrap factor, factory overhead, and non-production markup are incorporated into the cost of a pound of core steel as it is entered into the software design program. NEMA commented that it would be desirable to have manufacturers jointly agree on markup percentages to apply to the manufacturing data to arrive at a typical estimated manufacturer selling price. (NEMA, No. 7 at p. 6) In response to this recommendation, the Department calculated initial markup estimates based on U.S. Industry Census Data for 1992 and 1997 and Securities and Exchange Commission (SEC) 10–K reports for Acme Electric Corporation, Powell Industries, Magnetek, and Hammond Power Solutions. These initial markups were circulated in a draft engineering analysis report in December 2001 for comment.

AK Steel commented that initial scrap factor of 10 percent was too high for core steel and recommended that the Department use a 2 percent scrap factor. (AK Steel, No. 18 at p. 2) The Department discussed this comment with several manufacturers and with OPS, all of whom agreed that 10 percent was too high for core steel, but may be correct for insulation or wire. In recognition of the greater importance of core steel as a contributor to the manufacturer selling price of the transformer, the Department decided to use a scrap factor of 2.5 percent rather than 10 percent for all variable materials handled during manufacturing (*e.g.*, core steel, windings, insulation).

A stakeholder commented that the manufacturer's profit markup used in the December 2001 draft engineering analysis update report was too high, and the overhead markup was too low. (Klein, No. 17 at p. 2) The Department confirmed this comment during its interviews with manufacturers in early 2002. Based on input from the eight manufacturers visited, the Department revised its manufacturer raw-material markups as follows:

- Scrap factor: a 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).
- Factory overhead: a 12.5 percent markup, applied only to direct material costs, accounts for all the indirect costs associated with production, indirect materials and energy use, depreciation, taxes, and insurance.
- Non-production: a 25 percent markup applied to the sum of the direct material production, the direct labor, and the factory overhead. This markup reflects costs such as sales and general administrative, research and

development, interest payments, and profit factor.

Chapter 5 of the TSD also discusses the methodology followed to derive an industry average cost of labor. The Department calculated it initially from SEC 10–K reports, and solicited feedback from manufacturers during the early 2002 site visits. The Department started with a labor cost per hour of $14.31, and added a series of markups which brought the end-price of labor to $53.46 per hour. These markups include the burden of indirect production labor costs (33 percent), overhead (30 percent), fringe benefits (21 percent), assembly labor up-time (43 percent), and non-production markup (25 percent). The assembly labor up-time markup of 43 percent reflects a labor use rate of 70 percent, meaning that 30 percent of the time, production staff are not engaged in building transformers. All of these terms are defined in Chapter 5 of the TSD.

In combination with the cost of material and labor inputs, the OPS software used a range of what are known in the industry as A and B evaluation combinations (see TOC evaluation method in Chapter 3 of the TSD). These A and B evaluation values mimic hundreds of distribution transformer purchase orders. A represents a customer's net present value of future losses in the transformer core (no-load losses) and B represents a customer's net present value of future losses in the windings (load losses). These values take into account a range of factors depending on the customer. For utilities, some of the key variables include the avoided cost of generation, the avoided cost of transmission and distribution, the levelized fixed charge rate, and the equivalent annual peak load. For commercial and industrial customers, some of the key variables include the cost of capital, the energy demand costs, the peak load on the transformer, and the loss factor. The Department also used A and B values in the LCC analysis (see section II.F.2.c) to simulate customer purchasing behavior in the transformer market.

A and B are expressed in terms of dollars per watt of loss. The greater the values of A and B, the higher financial importance a customer attaches to the value of future transformer losses. As A and B values increase, the watts of core and winding losses decrease, and the resultant transformer efficiency increases.

For the engineering analysis, the Department used broad ranges of A and B evaluation values (presented in Chapter 5 of the TSD) capturing a comprehensive range of efficiency levels for each design option combination of core steel and winding material. During the 2002 site visits, manufacturers helped develop the range of values used. These values cover the spectrum of efficiencies represented in transformer orders from customers, as well as a low first-cost design and a maximum technologically feasible design. For the low first-cost design, the A and B evaluation values are both $0/watt, indicating that the customer does not attach any financial value to future losses in the core or coil of the transformer being bought. For the maximum technologically feasible design, the A and B evaluation values are higher, and were differentiated for this analysis between the liquid-immersed and dry-type distribution transformers.

In its December 2001 draft engineering analysis report, the Department had used A values for the liquid-immersed design lines that increased in increments of 0.25 and B values that increased by 0.10. However, using such fine increments of A and B value combinations resulted in more than 1,000 designs per design option combination, and more than 10,000 designs per representative unit. According to the manufacturers, these fine increments of A and B constituted an unnecessary level of detail for understanding the broader relationship between cost and efficiency. The revised analysis, published in June 2002, used the same range of A and B values, but with larger increments (0.50 on A and 0.25 on B). To identify the maximum technical efficiency potential for selected design option combinations, the Department applied an ''extended analysis'' of A and B values, thereby extending A values up to $16 and B values up to $6.

During the manufacturer site visits in early 2002, dry-type manufacturers requested that the Department use a different range of A and B values than those used for the liquid-immersed analysis. These manufacturers recommended considering a broader range of A and B value combinations, as well as higher B values. For the dry-type transformer analysis, the Department increased A and B values incrementally from lowest first-cost to $12/watt for A and to $8/watt for B. More information on the range of A and B values and the increments used to generate the engineering analysis design database is presented in Chapter 5 of the TSD.

4. Energy Efficient Design Issues

Several stakeholders commented that the Department should be aware that the performance characteristics and physical size of a distribution transformer changes as the efficiency improves. EEI commented that the two most important changes are an increase in available fault current and an increase in the physical dimensions of an equivalent kVA unit. (EEI, No. 6 at p. 3) This point was also made by TXU Electric and Gas. (TXU Electric and Gas, No. 12 at p. 7) These stakeholders expressed concern that when replacing a transformer with a new, more efficient unit, the customer's main electrical disconnect may not be rated for the increased fault current. Should this occur, it might cause the customer to replace equipment such as the electrical panel in addition to the transformer to maintain compliance with the National Electrical Safety Code. However, EEI cautioned that some companies may not choose to replace the electrical panel, thereby creating a safety hazard. (EEI, No. 6 at p. 4) Southern Company also highlighted the issue that a lower impedance on a more efficient transformer would increase available fault current. Utilities set minimum impedance levels to limit the available fault current at the transformer. (Southern Company, No. 8 at p. 6)

In order to address these concerns, the Department held the impedance of the designs created by the OPS software to an appropriate minimum value during the design phase (*e.g.*, 1.5 percent for a liquid-filled, 50 kVA, single-phase transformer) to ensure that the impedance does not become so low in highly efficient designs that it would result in dangerously high fault currents in the customer's breaker.

Stakeholders also commented that if the physical dimensions of a transformer increase under the standard, this increase could cause clearance and safety problems, according to the National Electric Safety Code. Whether the transformer is on a pole or a pad, the utility and/or the customer may incur additional installation costs, beyond the transformer installation costs. EEI noted that this criticism would not apply to new installations. (EEI, No. 6 at p. 4) To accommodate this comment in the analysis, the Department tracked the dimensions of all the designs created by the OPS software. For the larger, three-phase, dry-type units, the height of the cabinet was held at a common, standard industry dimension, while the length and width varied with the core/coil dimension. The LCC analysis also used this weight and dimensional data, as it directly impacts the shipping and installation costs.

Southern Company noted that more efficient transformers are typically larger and heavier. These units would have higher transportation costs and may require stronger poles. (Southern Company, No. 8 at p. 3) The OPS software calculates the weight of each of the transformers designed, and any additional handling and installation costs are included in the LCC analysis.

5. Engineering Analysis Results

The results of the engineering analysis are presented in Chapter 5 of the TSD and in two Microsoft Excel spreadsheets on the Department's website. All the designs created for each of the representative units from the thirteen design lines are presented. Hundreds of design variations are developed for each representative unit, spanning the broad range of efficiency levels and costs.

The OPS software produces design specification reports that include information about the core and coil assembly. The design report includes details about the core, high and low voltage windings, insulation, cooling ducts, and labor costs, that would enable a manufacturer to build a transformer at a given rating. The software also generates an electrical analysis report that estimates the performance of that design, including efficiency, core and coil losses at 25 percent, 35 percent, 50 percent, 65 percent, 75 percent, 100 percent, 125 percent, and 150 percent of nameplate load. When the database of OPS software designs is assembled, the output provides a clear understanding of the relationship between cost and efficiency because it incorporates data on the design, the bill of materials, the labor costs, and the efficiency.

The OPS manufacturing cost estimates assume an ideal situation where manufacturers do not incur retooling or special handling costs associated with changing materials or core/coil dimensions. NEMA stated its concern that the draft engineering analyses reports presented in December 2001 and August 2002 did not capture one-time costs and investments that will be required to design and manufacture design types that are outside the range of materials, technologies, and production methods currently used by manufacturers. NEMA believes that standard levels requiring materials and technologies beyond the existing range used by companies today will incur significant one-time costs. The ''Selling Price'' estimates provided in the analysis must incorporate timely recovery of these one-time costs by the manufacturers. (NEMA, No. 19 at p. 2)

The Department appreciates this comment because it highlights the importance of correctly reflecting the impact a regulation will have on the manufacturers of transformers. The recovery of one-time retooling costs is part of the manufacturer impact analysis (MIA), which will be conducted following the ANOPR workshop. The Department requests that reviewers, and particularly manufacturers, comment on the significant additional one-time costs they would incur if efficiency standards were introduced.

D. Energy Use and End-Use Load Characterization

This section presents the Department's estimation of the energy use and end-use load characterization for distribution transformers. Transformer loading is a factor that is important for determining which types of transformer designs will deliver a specified efficiency, and for calculating transformer losses. Transformer losses have two components: no-load losses and load losses. No-load losses are independent of the load on the transformer, while load losses depend approximately on the square of the transformer loading. Because load losses can increase dramatically with increased loading, there is a particular concern that during times of peak system load, load losses can impact system capacity costs and reliability. The Department received extensive comments on transformer loading due to its substantial implications for both transformer design and loss calculations.

NEMA recommended that the primary economic analyses on which a standard is based should be done using the TP 1 load levels of 35 percent and 50 percent, and that it may also be appropriate to calculate national energy savings based on a lower loading. (NEMA, No. 7 at p. 9) ACEEE commented that commercial building distribution transformers have been shown to have low capacity factors (typically around 20 percent), that 16 percent is an appropriate value for low-voltage dry-type transformers, and that the 20–30 percent value for utility distribution company (UDC) transformers seemed reasonable. (ACEEE, No. 21 at p. 1; ACEEE, No. 14 at p. 2) In contrast, TXU Electric and Gas noted that it is not unusual to allow peak load levels on a transformer serving residential customers to go as high as 130 percent of nameplate load during the summer or 160 percent during the winter and suggested that in a UDC environment the loading level number may be somewhere higher than the NEMA recommended 50 percent. (TXU Electric and Gas, No. 12 at p. 6) Copper Development Association (CDA) commented that several transformer manufacturers recommend loading their product to at least 60–70 percent of the nameplate rating, and that higher loading levels are recommended in applications where there is no need for overload capacity. (CDA, No. 9 at p. 2) Southern Company noted that most large utilities have a wealth of information concerning transformer loading and loading practices, and that the Department should be able to gather needed information from utilities to evaluate current data on loading and typical average and peak loads on distribution transformers. (Southern Company, No. 8 at p. 4)

The Department developed detailed models of the transformer loads and based features of its models on hourly data obtained from utility and public sources (see Chapter 6 of the TSD). The analysis resulted in average initial load levels for liquid-immersed transformers ranging from 30 percent for 25 kVA transformers to 59 percent for 1500 kVA transformers and average life-time load levels of 35 percent and 70 percent, respectively. The shipment-weighted lifetime average loading is 52.9 percent. These load levels are within the range suggested in the aforementioned comments submitted by NEMA and TXU Electric and Gas.

For dry-type transformers, the Department's analysis resulted in average load levels ranging from 32 percent to 37 percent (depending on transformer size), which are consistent with some initial comments by NEMA but are higher than load levels recommended by many of the comments on the actual loading of dry-type transformers. Shipment-weighted lifetime average loading is 33.6 percent for low-voltage dry-type and 36.5 percent for medium-voltage dry-type. The Department's estimate for low-voltage dry-type transformers is quite close to the NEMA recommendation, but the estimate for medium-voltage dry-type transformers is substantially lower than the 50 percent loading recommended by NEMA for economic evaluation. This is because the estimate of 75 percent initial peak load and the load factors estimated from the hourly building load data are consistent with the lower average loading. The Department estimated that the initial peak loading of dry-type transformers should be 75 percent if transformers are sized primarily by using engineering criteria. NEMA later commented that the actual initial load is less than 50 percent for dry-type transformers in commercial buildings. (NEMA, No. 26 at p. 3) Currently, the Department examines the low initial load case as a sensitivity case for low-voltage dry-type transformers. For this sensitivity case, average loadings are about 20 percent. The Department invites additional comment and data regarding the loadings of both low-voltage and medium-voltage, dry-type transformers and specific comments on whether the current 75 percent average initial peak loading used by the Department should be lowered to 50 percent as recommended by NEMA's more recent comment. Comments may also address the possibility of using 50 percent average initial peak loads for commercial applications and 75 percent initial peak loads (or higher) for industrial applications, or different initial peak loadings for low-voltage and medium-voltage, dry-type transformers.

The Department also received substantial comment on specific technical details of transformer loading. There is a degree of coincidence between transformer loads and either system or building loads during the time of peak load. Load coincidence is measured by a peak responsibility factor (PRF), defined as the square of the ratio of the transformer load during the time of the annual system or building peak, and the annual peak load of the transformer. The Department's analysis estimated peak coincidence factors from available hourly building load data obtained from a Bonneville Power Administration study and provided by an electric utility stakeholder, as described in detail in Chapter 6 of the TSD.

On peak load coincidence, EEI commented that transformer load profiles often do not correlate to the facility load profiles. (EEI, No. 28 at p. 2) Also, a stakeholder was concerned that the Department may use standardized loading assumptions, and that there is no mention of diversity, or the low likelihood that the peak load on the transformer will coincide with the utility peak, such as in a church. (L.G. Spielvogel, Inc., No. 39 at p. 1) In contrast, CDA commented that for the commercial and industrial sector, transformer peak times are expected to roughly correspond with system peak times. (CDA, No. 43 at p. 2)

The Department's analysis of peak load coincidence is consistent with these comments because the analysis incorporates the range and diversity of conditions described by the stakeholders. Residential and certain commercial loads were found to have low coincidence with system peak load, while industrial and certain commercial loads have a high degree of coincidence. The average PRF ranges from 31 percent for 25 kVA, pole-mounted, liquid-immersed transformers (which serve a large proportion of residential and small commercial loads) to 68 percent for 1500 kVA, liquid-immersed, pad-mounted transformers. For dry-type transformers, the PRF average values range from 47 percent to 54 percent, depending on the transformer owners assumed for a given design line. The data available to the Department does not provide information that allows a detailed analysis of dry-type transformer peak coincidence factors with commercial and industrial whole-building loads. As highlighted in section IV.E, the Department requests additional specific commentary and load data regarding transformer applications for commercial and industrial users.

E. Markups for Equipment Price Determination

This section explains how the Department developed markups to the equipment prices to derive installed transformer prices (see TSD Chapter 7). Supply-chain markup and installation costs are the costs associated with bringing a manufactured transformer into service as an installed piece of electrical equipment. NEMA pointed out that determining user costs for dry-type transformers is difficult because transformers pass through a wide range of channels before reaching the ultimate owner. (NEMA, No. 7 at p. 6)

In the LCC analysis (see section II.F), the Department applied the following price markups to the manufacturing costs of dry-type transformers: distributor markup, contractor materials markup, installation labor and equipment markup and sales tax. The Department did not apply the distributor and contractor materials markups to liquid-immersed transformers but did apply the markup on installation labor and equipment, since utilities generally purchase their transformers directly from manufacturers and install the transformers themselves. The Department did not have sufficient data to diversify the distribution channels and markups beyond these two cases. The Department requests feedback from stakeholders on which distribution channels are most common for the different types of distribution transformers.

The Department estimated these markups for dry-type transformers (expressed as average multipliers) from RS Means Electrical Cost Data 2002. The Department used RS Means data because it is widely used in the industry. Table II.7 lists the average markups used in this ANOPR; additional detail is provided in Chapter 7 of the TSD.

TABLE II.7.—SUPPLY-CHAIN MARKUPS

LCC analysis markups	Average multiplier
Distributor	1.350
Contractor Materials	1.100
Installation Labor and Equipment	1.520
Sales Tax	1.054

For dry-type transformers, the distributor applies a markup to the manufacturer selling price to arrive at a distributor price, which is the price paid by the electrical contractor. This distributor markup reflects the cost of distribution, including sales labor, warehousing, overhead, and profit for the distributor. The contractor markup applied to the distributor price covers contractor overhead and profit for the sale of the transformer. Installation labor and equipment markup accounts for the overhead costs of labor and the wear and tear of equipment used during the installation process. In calculating total installation costs, the Department used the weight of each specific design as one of the input variables to determine installation cost. Shipping costs are also added. The Department estimated average shipping costs based on the transformer weight using an average unit shipping cost of $0.20/lb. Finally, the Department added a sales tax to the total cost, resulting in the total installed cost. For liquid-immersed distribution transformers, the total installed cost includes the manufacturer selling price, plus the weight specific installation labor and equipment costs, installation labor and equipment markup, shipping cost, and sales tax.

Southern Company noted in its comments that heavier, pole-mounted transformers might also require stronger, more expensive utility poles. (Southern Company, No. 8 at p. 3) The Department did not explicitly model this potential effect due to a lack of data on the relationship between the extra weight that more efficient models might have and the ability of standard utility poles to support transformers with that extra weight, the added costs of such poles if they were required, and the fraction of transformers that might be subject to this effect. The Department requests such data from utilities or other stakeholders who might have it. As highlighted in section IV.E, the Department requests feedback from stakeholders on markup costs to refine supply-chain markup cost estimates.

F. Life-Cycle Cost and Payback Period Analyses

When DOE is determining whether an energy efficiency standard for distribution transformers is economically justified, it takes into consideration the economic impact of potential standards on consumers (42 U.S.C. 6317(c) and 42 U.S.C. 6295(o)(2)(B)). To accomplish this, the Department calculated changes to consumers' LCCs which are likely to result from a candidate standard level, as well as producing a distribution of PBPs (see TSD Chapter 8). The effects of standards on individual consumers include changes in operating expenses (usually lower) and changes in total installed cost (usually higher). The Department analyzed the net effect of these changes by calculating the changes in LCCs compared to a base case. The LCC calculation considers total installed cost (equipment purchase price plus installation cost), operating expenses (energy and maintenance costs), equipment lifetime, and discount rate. The Department performed the LCC analysis from the perspective of the user of the distribution transformer equipment. The PBP is an estimate of the time required to recover the incremental cost increase of a more efficient transformer from the operating cost savings.

The LCC and PBP results are presented to facilitate stakeholder review of the LCC analysis. Similar to the LCC analysis, the PBP is based on the total cost and operating expenses. But unlike the LCC analysis, only the first year's operating expenses are considered in the calculation of PBP. Because the PBP analysis does not take into account changes in operating expense over time or the time value of money, it is also referred to as a ''simple'' payback period.

On the broad issue of calculating LCC savings, TXU Electric and Gas noted that the input parameters necessary to calculate that savings are volatile. Variances in load characteristics such as peak demand and load factor and variation in energy costs which range from 3 to 15 cents per kWh make calculation of any energy savings uncertain. (TXU Electric and Gas, No. 12 at p. 9)

The Department generated LCC and PBP results as probability distributions using a simulation based on Monte Carlo statistical analysis methods in which inputs to the analysis spreadsheets consist of probability distributions rather than single-point values. As a result, the Monte Carlo analysis produces a range of LCC and PBP results. A distinct advantage of this type of approach is that the Department can estimate the percentage of users that achieve particular LCC savings or attain certain PBP values due to an efficiency standard, in addition to the average LCC savings or average PBP for that standard. Because DOE conducted the analysis in this way, it can express the uncertainties associated with the various input variables as probability distributions. During the post-ANOPR LCC sub-group analysis, the Department intends to evaluate additional parameters and prepare a comprehensive assessment of the impacts on sub-groups of users.

The Department developed spreadsheet models in Microsoft Excel to calculate the LCC and PBP. An add-in to Microsoft Excel called Crystal Ball (a commercially available software program by Decisioneering) allows for input variables to be characterized with probability distributions. The spreadsheet models are available for download from the Department's website.

The Department performed a sensitivity analysis of LCC model inputs to examine which inputs have the greatest affect on LCC results. See the LCC Inputs, section II.F.2.

1. Approach Taken in the Life-Cycle Cost Analysis

The LCC analysis estimates the impact on consumers of potential energy efficiency standards by calculating the net cost of a transformer under a base case of no standard and a standards case of only standard-compliant transformers being available in the market. The first step in calculating the net cost of a transformer is specifying the distribution of possible transformer designs and the attendant equipment and installation costs associated with each design. The engineering analysis provides the manufacturer costs for each transformer design. As explained in section II.E, the Department estimates the final installed cost by multiplying the manufacturer's selling price by the appropriate markups, then adding sales tax, shipping costs, and installation costs.

Next, the calculation includes a purchase-decision model that determines which of the many designs a customer selects. A fundamental input to the purchase-decision model is the proportion of transformers bought using an evaluation of the economic impact of losses. Section II.F.2.c on baseline and standard design selection discusses this fundamental input in more detail. Once the base case and standards case designs are selected for a customer, the Department estimates the customer load characteristics, which determine the transformer no-load and load losses.

The Department created two sets of electricity prices to estimate annual energy expenses: a tariff-based estimate and an hourly-based estimate. The Department applied the tariff-based approach to dry-type transformers, owned primarily by commercial and industrial customers. The Department applied the hourly-based approach to liquid-immersed transformers, used primarily in utility applications. The tariff-based approach estimates an annual energy expense using retail electricity prices determined from electric utility tariffs collected in 2002. The hourly-based approach estimates annual energy expense using marginal utility wholesale electricity costs from 1999, the most recent available data from the Federal Energy Regulatory Commission (FERC) when the analysis was performed. For the NOPR analysis, the Department will use the most current data available. For the hourly-based estimate, the Department collected electricity production prices that vary on an hourly basis and then used them to model the marginal electricity costs incurred by utilities from hourly losses. For electricity markets in which there is some level of competition, the Department collected actual wholesale hourly electricity prices. For markets that are still fully price-regulated, the Department collected hourly system-load and generation-cost data.

The Department then estimated the final LCC value for each design and each customer using a real discount rate that represents the average cost of capital for that customer. After repeating the calculation for many customers and many designs, the Department calculated the distribution of net LCC impacts of each candidate standard level.

2. Life-Cycle Cost Inputs

For each efficiency level analyzed, the LCC analysis requires input data for the total installed cost of the equipment, the operating cost, and the discount rate. Table II.8 summarizes the inputs and key assumptions used to calculate the customer economic impacts of various energy efficiency levels. Equipment price, installation cost, and baseline and standard design selection affect the installed cost of the equipment. Transformer loading, load growth, power factor, annual energy use and demand, electricity costs, electricity price trend, and maintenance costs affect the operating cost. Discount rate and lifetime of equipment affect the calculation of the present value of annual operating cost savings from a proposed standard.

TABLE II.8.—SUMMARY OF INPUTS AND KEY ASSUMPTIONS USED IN THE LCC ANALYSIS

Input	Description
Transformer loading	Loading depends on customer and transformer characteristics. The average initial liquid-immersed transformer loading is 30% for 25 kVA and 59% for 1500 kVA transformers. The average initial dry-type transformer loading is 32% for 25 kVA and 37% for 2000 kVA transformers. The shipment-weighted lifetime average loading is 33.6% for low-voltage dry and 36.5% for medium-voltage dry. With load growth, average installed liquid-immersed transformer loading is 35% for 25 kVA and 70% for 1500 kVA transformers with a shipment-weighted lifetime average loading of 52.9%. See section II.D.
Annual energy and demand	Derived from a statistical hourly load simulation for use liquid-immersed transformers, and estimated from the 1995 Commercial Building Energy Consumption Survey data for dry-type transformers using factors derived from hourly load data. Load losses vary as the square of the load and are equal to rated load losses at 100% loading. See section II.D.
Equipment price	Derived by multiplying manufacturer selling price (from the engineering analysis) by distributor markup and contractor markup plus sales tax for dry-type transformers. For liquid-immersed transformers, manufacturer selling price plus sales tax is used. Shipping costs are included for both types of transformers. See section II.E.
Installation cost	Includes a weight-specific component, derived from RS Means Electrical Cost Data 2002 and a markup to cover installation labor, and equipment wear and tear. See section II.E.
Effective Date of Standard	Assumed to be 2007 for this analysis.
Candidate Standard Levels	Five efficiency levels for each design line with the minimum equal to TP 1 and the maximum from the most efficient designs from the engineering analysis.
Baseline and standard design selection.	The selection of baseline and standard-compliant transformers depends on customer behavior. For liquid-immersed transformers, the fraction of purchases evaluated is 50%, while for dry-type transformers, the fraction of evaluated purchases is 10%. The average A value for evaluators is $5/watt, while the B value depends on expected transformer load.*
Power Factor	Assumed to be unity.
Load growth	One percent per year for liquid-immersed and 0% per year for dry-type transformers.
Electricity costs	Derived from tariff-based and hourly-based electricity prices. Capacity costs provide extra value for reducing losses at peak. Average marginal tariff-based retail electricity price: 6.4¢/kWh for no-load losses and 7.4¢/kWh for load losses. Average marginal wholesale utility hourly-based costs: 3.8¢/kWh for no-load losses and 4.5¢/kWh for load losses.
Electricity price trend	Obtained from Annual Energy Outlook 2003 (*AEO 2003*). Average real price change from 2001 to 2020 is −9%, −6%, −12%, and 0% for the reference, high growth, low growth, and constant real price scenarios, respectively.
Lifetime	Distribution of lifetimes, with mean lifetime for both liquid and dry-type transformers assumed to be 32 years.
Maintenance cost	Annual maintenance cost does not vary as a function of efficiency.
Discount rates	Mean real discount rates range from 4.2% for owners of pole-mounted, liquid-immersed transformers to 6.6% for dry-type transformer owners.

* The concept of using A and B evaluation combinations was introduced in section II.C.3, Developing the Engineering Analysis Inputs. Within the context of the LCC analysis, the A factor measures the value to a transformer purchaser, in $/watt, of reducing no-load losses while the B factor measures the value, in $/watt, of reducing load losses. The purchase decision model developed by the Department mimics the likely choices that consumers make given the A and B values they assign to the transformer losses.

The Department performed a sensitivity analysis of LCC model inputs to examine which ones have the greatest impact on LCC results. The LCC results are most sensitive to three parameters in the purchase decision model: fraction of purchases evaluated, cost of electricity, and loading estimates. The single most sensitive input is the fraction of purchases in which transformer losses are evaluated during a purchase. The input with the next most significant impact is the cost of electricity. Electricity price trends have an indirect effect on the average cost of electricity over time while the initial estimate of electricity costs has a relatively larger impact on LCC results. The third most significant impact on LCC results derives from the loading estimates. Loading estimates are affected mostly by transformer sizing practices and secondarily by technical details of the load characteristics.

The power factor estimate affects the LCC results through its effect on load loss estimates. Depending on the customer profile for a given LCC analysis, discount rates can also have a large impact on LCC results. Other inputs such as lifetime, maintenance costs, and installation costs have a relatively small impact on LCC results when compared to inputs such as those mentioned above.

As noted by its absence in Table II.8, the Department chose not to include the impact of income taxes in the LCC analysis for this ANOPR. The Department understands that there are two ways in which taxes affect the net impacts of purchasing more energy efficient equipment compared to baseline equipment: (1) Energy efficient equipment typically costs more to purchase than baseline equipment which in turn lowers net income and may lower company taxes; and (2) efficient equipment typically costs less to operate than baseline equipment which in turn increases net income and may increase company taxes. In general, the Department believes that the net impact of taxes on the LCC analysis depends upon firm profitability and ''expense'' practices (how firms expense the purchase cost of equipment). The Department seeks input on whether income tax effects are significant enough to warrant inclusion in the LCC analysis for the NOPR. The Department specifically requests information on how many utilities and commercial and industrial firms that purchase distribution transformers have net Federal and/or state income tax liability and, if they do, what ''expense'' practices they use to depreciate the purchase costs.

a. Effective Date of Standard

The Department is planning to propose that the effective date of any new energy efficiency standard for distribution transformers be three years after the final rule is published. The Department has been conducting analysis supporting this ANOPR since the framework document workshop in 2000. Early on, the Department assumed that the final rule would be issued in 2004 and that the new standard would take effect in 2007 and used these dates in the LCC and national impacts analyses. The Department recognizes that these dates are now unlikely to be achieved. Adjusting the effective date by a year or two will have relatively small impacts on the analysis LCC and national impacts results presented in this ANOPR. For the NOPR analysis, the Department will adjust these dates to accurately reflect the probable rule schedule at that time. The Department calculated the LCC for customers as if each new distribution transformer purchase occurs in the year the standard takes effect. The Department based the cost of the equipment on that year.

b. Candidate Standard Levels

The Department must first select efficiency levels to examine before it can conduct an analysis of the impact of candidate standard levels (CSL). NEMA suggested four efficiency levels: (1) A low-cost baseline design (lowest installed cost that meets all safety and performance requirements); (2) TP 1 level; (3) the maximum efficiency design (the highest efficiency products capable of being manufactured, irrespective of cost), or an alternative that is a fixed percentage improvement of the difference between TP 1 and 100 percent efficiency—in this case, about a 25–30 percent improvement over TP 1; and (4) an efficiency level halfway between TP 1 and maximum efficiency. (NEMA, No. 7 at pp. 7–8)

The American Council for an Energy Efficient Economy (ACEEE) recommended analysis of five efficiency levels: (1) The Department's proposed baseline (the least efficient transformer available on the market); (2) NEMA TP 1; (3) an efficiency level based on an approximately 7-year simple payback; (4) an efficiency level based on an approximately 12-year simple payback (which approximates the minimum life-cycle cost point for a 30-year product life with a 7-percent real discount rate); and (5) the maximum technologically feasible efficiency level. (ACEEE, No. 14 at p. 2)

Since the LCC analysis produces payback as an output, PBPs could not be used directly as an input for a particular candidate standard level. The Department's LCC model is flexible, and adjusting inputs and assumptions will produce different LCC outputs, including PBPs. Stakeholders are invited to use the spreadsheet models (posted on DOE's website) to explore how changing the inputs results in different payback outputs. The PBP results produced as part of the ANOPR include values similar to those requested by stakeholders but the Department did not conduct an explicit analysis exploring sets of inputs that produced specific PBP outputs.

The Department started with these NEMA and ACEEE comments and then examined distribution transformer cost/efficiency relationships from the engineering analysis and found that TP 1 efficiency levels could be obtained with relatively small cost increases over the lowest cost designs for all design lines. Therefore, the Department decided that evaluating a CSL between the lowest cost designs and the TP 1 efficiency level was not warranted, resulting in TP 1 as the minimum CSL. For each design line, the Department set the maximum CSL among the most efficient transformers in that engineering design line. The Department created three other CSLs between the minimum and maximum efficiency levels, approximately equally proportioned so as to capture cost and benefit impacts at a total of five roughly equally spaced standard levels, unique to each design line. The Department believes that analyzing this distribution of five CSLs for each of the 13 engineering design lines will provide sufficient information for considering a broad and meaningful range of efficiency ratings. The lowest candidate standard level is NEMA's TP 1, and the highest has losses that are 10 percent greater than the most efficient design identified in the engineering analysis. Table II.9 lists the candidate standard levels, expressed in terms of efficiency, and in terms relative to NEMA TP 1 efficiency levels.

TABLE II.9.—CANDIDATE STANDARD LEVELS EVALUATED FOR EACH DESIGN LINE

Design line	CSL 1		CSL 2		CSL 3		CSL 4		CSL 5	
	TP 1+ (%)	Efficiency (%)	TP 1+ (%)	Efficiency (%)	TP 1+ (%)	Efficiency (%)	TP 1+ (%)	Efficiency (%)	TP 1+ (%)	Efficiency (%)
DL 1	0.00	98.90	0.20	99.10	0.40	99.30	0.50	99.40	0.68	99.58
DL 2	0.00	98.70	0.20	98.90	0.40	99.10	0.60	99.30	0.77	99.47
DL 3	0.00	99.30	0.10	99.40	0.30	99.60	0.40	99.70	0.45	99.75
DL 4	0.00	98.90	0.20	99.10	0.40	99.30	0.50	99.40	0.66	99.56
DL 5	0.00	99.30	0.10	99.40	0.20	99.50	0.30	99.60	0.36	99.66
DL 6	0.00	98.00	0.20	98.20	0.40	98.40	0.70	98.70	0.79	98.79
DL 7	0.00	98.00	0.30	98.30	0.60	98.60	0.90	98.90	1.09	99.09
DL 8	0.00	98.60	0.20	98.80	0.40	99.00	0.60	99.20	0.67	99.27
DL 9	0.00	98.60	0.20	98.80	0.40	99.00	0.60	99.20	0.71	99.31
DL 10	0.00	99.10	0.10	99.20	0.20	99.30	0.30	99.40	0.34	99.44
DL 11	0.00	98.50	0.20	98.70	0.40	98.90	0.50	99.00	0.60	99.10
DL 12	0.00	99.00	0.10	99.10	0.30	99.30	0.40	99.40	0.45	99.45
DL 13	0.00	99.00	0.10	99.10	0.30	99.30	0.40	99.40	0.45	99.45

c. Baseline and Standard Design Selection

A key factor in estimating the economic impact of a proposed standard is the selection of transformer designs in the base case and standards case scenarios. The key issue is the degree to which transformer purchasers will buy transformers that have a minimum LCC for their application without the promulgation of a standard, compared to purchasing behavior with an efficiency standard in place.

The Department received many comments on design selection and purchase behavior and developed a purchase decision model that tries to incorporate many of the stated concerns. The engineering analysis provides cost and efficiency characteristics for between 150 and 300 designs for each design option combination in each of the 13 engineering design lines. The purchase decision model in the LCC analysis selects which of the hundreds of designs are likely to be selected by transformer purchasers.

Southern Company commented that 54 percent of the distribution transformer line items that it buys and 75 percent by volume of the 300 line items bought currently meet the TP 1 efficiency standard. It concluded that the ‘‘assumption that the baseline model would be the ‘typically sold, low efficiency’ model in the marketplace’’ may not be a valid assumption. (Southern Company, No. 8 at p. 2) NEMA had commented earlier in the rulemaking that the baseline models used for the representative ratings analyses should be the transformers currently being sold when the life-cycle cost or total owning cost is not considered by the purchaser. (NEMA, No. 7 at p. 6) NRDC and EEI argued that because of electricity restructuring, utilities are moving away from TOC evaluation of transformer purchases. (NRDC, No. 5 at p. 3; EEI, No. 24 at p. 2) EEI noted that for UDCs, competitive retail markets are eliminating their ability to gain any economic return for installing high-efficiency transformers. (EEI, No. 24 at p. 3) Under such conditions, utility companies would tend to buy those transformers that have the lowest installed cost. HVOLT agreed for slightly different reasons, noting that because of the generation glut that occurred in 2001–2002, the 2003 A and B values have dropped to $0/watt in many parts of the country (see section II.C.3). (HVOLT, No. 42 at p. 1)

On the other hand, METGLAS Solutions disagreed that an overwhelming fraction of purchasers give little or no weight to losses in their evaluations. It argued that it is not true that only a small segment of the country has large A and B factors, especially when one takes a global perspective. For example, in Japan the A factor is close to $10 and in many European countries it is close to $8. (METGLAS Solutions, No. 16 at p. 2) And in a later comment, NEMA provided some quantitative detail on the fraction of higher efficiency transformers currently bought by noting that the market share of liquid-filled transformers satisfying TP 1 has gone from nearly 100 percent a few years ago to about 50 percent today. (NEMA, No. 26 at p. 4)

The Department, in its purchase-decision model for liquid-immersed transformers, assumed that 50 percent of transformer purchases are based on an evaluation process using A and B values. These A and B values are characterized as distributions with a mean of $5/watt for the A factor. A majority of purchases either have low A factors or are not evaluated, yet a large fraction (approximately 25 percent) have A factors larger than $5/watt. The Department does not currently model trends in the number of evaluators, but instead estimates that transformer evaluation behavior will be the same in the future as it is currently. The details of the transformer design selection are provided in the TSD, Chapter 8. As highlighted later in section IV.E, the Department requests input from interested parties on the purchase-decision model and transformer-evaluation-behavior for liquid-immersed transformers. Additional information on the fraction of evaluated purchases for different categories of transformers, specific trends or forecasts of evaluation behavior, and the average A factor values for such evaluations will be particularly valuable for the LCC analysis.

Evaluation is less common for dry-type transformers than it is for liquid-immersed transformers. EEI recommended that for dry-type transformers, DOE use the non-evaluation scenario (0 percent conducting evaluation). (EEI, No. 28 at p. 2) HVOLT agreed that many commercial and industrial customers make purchases, based on lowest first cost, but it found a significant percentage that will support a 3–5 year payback and would go as high as $1.50/watt for no-load losses (A) and as high as $0.35/watt for load losses (B). (HVOLT, No. 42 at p. 1) NEMA commented that for low-voltage, dry-type transformers, the market is commercial buildings. Commercial building owners are interested in the lowest first cost and typically their tenants pay the electric bills, leading to a low use of high efficiency transformers results, while about 25 percent of medium-voltage, dry-type transformers meet the TP 1 standard. (NEMA, No. 26 at pp. 2–3)

The Department, in its purchase-decision model for dry-type transformers, assumed that 10 percent of transformer purchases are based on an evaluation process using A and B values. To give an example of how this drives purchasing behavior, the Department’s current customer-design-selection model estimates that the average baseline efficiency for 75 kVA, low-voltage, three-phase, dry-type transformers on the market is 96.4 percent at 35 percent loading compared to the TP 1 standard level of 98.0 percent. As highlighted in section IV.E, the Department requests input from interested parties on the customer-design-selection model and transformer-evaluation-behavior for dry-type transformers. Specific issues include the actual efficiency of the low first-cost designs currently on the market. The efficiency of the low first-cost designs has a large impact on overall energy savings estimates. Additional issues include whether the fraction of evaluators for low-voltage, dry-type transformers should be lowered to 0 percent as recommended by EEI, and raised to 25 percent for medium-voltage, dry-type transformers as implied by NEMA’s comment. The average A-factor value is also a significant issue, and additional comments are invited on whether the Department should use an A-factor different from the current assumptions.

d. Power Factor

The power factor 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 voltage and the root mean square current. When specifying transformer efficiency, specifications such as NEMA’s TP 1–2002 assume a power factor of 1.0. Thus, in the absence of any specific data or guidance on the appropriate power factor, the Department used a power factor of 1.0 in calculating the efficiency levels for its engineering analysis and used a power factor of 1.0 when it analyzed candidate standard levels for this ANOPR.

However, in real-world installations, the loads experienced by distribution transformers are likely to have power factors of less than 1.0. The National Rural Electric Cooperative Association (NRECA) commented that setting the power factor to the value of 1.0 is probably not adequate for most transformers since they service loads with less than a unity power factor. (NRECA, No. 40 at p. 4) Because the LCC analysis models transformers installed and operated in the field, DOE created a spreadsheet with an adjustable power factor, thereby enabling the LCC to run at power factors lower than 1.0. The Department requests specific stakeholder comment on the power factor of 1.0 assumption.

e. Load Growth

The LCC projects the operating costs for transformer operation many years into the future. This requires an estimate of how the load on individual transformers will change over time, *i.e.*, the load growth. On this issue, CDA observed that a transformer's initial loading is almost certain to increase over its typically long service life of approximately 40 years. CDA also stated that since transformers tend to stay in place for decades once installed, what appears to be light loading in a new subdivision may become dramatically higher over time. CDA believes that more research is needed and the Department should be cautious in assuming that low load factors are typical across the spectrum of the residential market. (CDA, No. 9 at pp. 4–5) NEMA stated that the Department's assumption that the loads on transformers grow by 1 percent per year is incorrect. It agreed that the overall growth in transformer loads is 1–2 percent per year, but stated that for medium-voltage, dry-type transformers, this growth is met by the purchase of additional transformers, not by increased load on existing transformers. It suggested that the load growth per transformer should be zero percent. (NEMA, No. 26 at p. 3) NRECA commented that while the Department's transformer load growth model has 0 percent, 1 percent, or 2 percent per year input selections available, this may not be adequate to represent load growth on rural electric transformers. (NRECA, No. 40 at p. 4) HVOLT commented that transformer loads start out with nearly the same load that they will see for their expected life since residential transformers are assigned to a group of homes that are usually built within a couple of years of each other. Heating/cooling, water heating, laundry, and cooking are the big loads that begin as soon as the service is installed and there is little subsequent residential load growth. However, commercial and industrial transformers, *i.e.* medium-voltage dry-type, are sized to satisfy their intended loads, and new load expansion results in installation of a new transformer. (HVOLT, No. 42 at p. 1) CDA noted that it is reasonable to expect residential transformer loading to increase over time as people add appliances and air conditioning to existing dwellings. Also, CDA found many instances where loads increased in commercial structures due to the addition of electrical loads to existing buildings. (CDA, No. 43 at p. 2) The Department received stakeholder guidance during the October 17, 2002, webcast that a zero-percent load growth was the preferable default for dry-type distribution transformers.

For liquid-immersed transformers, the Department used as the default scenario a 1-percent-per-year load growth, *i.e.*, a medium rate, as identified in ORNL–6847, Determination Analysis of Energy Conservation Standards for Distribution Transformers. For dry-type transformers, the Department applied a zero-percent load growth. The Department applied the load growth factor to each transformer beginning in 2007, the expected effective date of the standard. For exploration of the LCC sensitivity to variations in load growth, the Department included the ability to examine scenarios with 0-percent, 1-percent, and 2-percent load growth. As highlighted in section IV.E, the Department seeks comments from stakeholders on the issue of load growth.

f. Electricity Costs

The Department needs estimates of electricity prices and costs to place a value on transformer losses for inclusion in the LCC calculation. Stakeholders had a series of suggestions regarding the electricity prices and costs that the Department should use in its LCC analysis. NEMA stated that for utility applications, the Department should use average utility electricity costs as the basic electricity price. It urged DOE to seek input from utilities on their current rates. (NEMA, No. 26 at pp. 2–3) NEMA suggested that for commercial and industrial applications, DOE should use average electricity prices. (NEMA, No. 7 at p. 11) NEMA also commented that since deregulation, electricity rates for all customers have decreased. In addition, NEMA noted that many large industrial customers have negotiated rates that merely keep them as customers, with little or no utility profit. Utilities have done this to maintain load factors and the industrial rate in this case is near their cost. Therefore, DOE should seek input from public- and investor-owned utilities on rates. (NEMA, No. 26 at p. 3)

NRDC urged DOE to look carefully at recent energy price trends and to include in the range of its analysis the levels of upward variation in price that occurred in California during 2001. (NRDC, No. 5 at p. 5, No. 25 at p. 2, No. 27 at pp. 2–3) CDA commented that a heavily loaded transformer that was designed to minimize mainly no-load losses will have significantly greater load losses than no-load losses during peak times. It is also at these peak times that cost per kWh is highest and the economic justification is greatest to address load losses. (CDA, No. 9 at p. 3) CDA also urged the Department to consider the effect of minimization of the load loss of transformers on peak-hour utility demands. CDA also commented that there is a large variation in electricity costs among utilities, with some utilities charging relatively high electricity prices for industrial customers. (CDA, No. 43 at p. 2) HVOLT commented that NEMA used $0.065/kWh which continues to be close to reality. (HVOLT, No. 42 at p. 1) NRECA commented that marginal electricity prices are not necessarily something that a distribution cooperative can determine accurately, at least not on an hour-by-hour basis, because most electricity purchases by cooperatives are not made based upon hourly differentiated rates. (NRECA, No. 40 at p. 3)

Since the liquid-immersed transformer market is dominated by utilities, the Department used marginal wholesale electricity prices to reflect peak impacts for the liquid-immersed design lines (see TSD Chapter 8). For utilities, marginal wholesale electricity prices are the prices experienced for the last kWh of electricity produced. A utility's marginal price can be higher or lower than its average price, depending on the relationships between capacity, generation, transmission, and distribution costs. The general structure of the hourly marginal cost equation divides the costs of the electricity into capacity components and energy cost components. The capacity components include generation capacity, transmission capacity, and distribution capacity. Capacity components also include a reserve margin needed to assure system reliability. Energy cost components include a marginal cost of supply that varies by hour, factors that account for losses, and cost recovery of associated marginal expenses. The Department applied this specific equation to the calculation of the marginal wholesale cost of supply of electricity to cover transformer losses. The Department used published FERC Form 714 data and California, Pennsylvania and New York electricity market data for the year 1999 to determine these costs.

Since the dry-type transformer market is dominated by commercial and industrial customers, the Department's calculation of monthly customer incremental retail electricity costs from transformer losses used a representative set of actual utility tariff formulas from the year 2002. Utility tariffs include fixed charges, energy (per kWh) charges, and demand (per kW) charges. Utilities typically group the rates for the different charges by blocks defined by levels of energy use and demand. The tariff formulas contain a series of blocks and several parameters per block which define the charges in that block of use. The LCC spreadsheet for dry-type transformers contains a customer bill calculator that calculates customer bills based on information collected from a representative set of utility tariffs, seasonal charges, tariff blocks, and the fixed, energy, and demand charges in each block. The Department collected 218 published utility tariffs from 90 utilities to provide the data for the bill calculator.

As highlighted in section IV.E, the Department seeks input from stakeholders regarding the appropriate energy costs to use in this rulemaking.

g. Electricity Price Trends

NRDC commented that all three of the proposed electricity price trend scenarios explore real electricity price increases relative to 2001 prices. (NRDC, No. 27 at p. 2) CDA commented that there are growing indications that electricity prices will not be declining in future years as demand catches up with, and perhaps exceeds, available generation and transmission capacity. (CDA, No. 43 at p. 2)

For the relative change in electricity prices for future years, the Department used the price trends from three *AEO 2003* forecast scenarios and a constant real price scenario. LCC spreadsheet users have the choice of four scenarios: *AEO 2003* low growth scenario, *AEO 2003* reference scenario, *AEO 2003* high growth scenario, and constant real price scenario. To reflect the uncertainty in forecasts of economic growth, the *AEO 2003* forecasts use high and low economic growth cases along with the reference case to project the possible energy markets. The high economic growth case incorporates higher population, labor force, and productivity growth rates than the reference case. Investment, disposable income, and industrial production are higher and economic output is projected to increase by 3.5 percent per year between 2001 and 2025. The low economic growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the low economic growth case, economic output is expected to increase by 2.5 percent per year over the forecast horizon. The ANOPR uses the trend from the reference scenario, 3.0 percent, as its default ‘‘medium’’ scenario.

h. Equipment Lifetime

The Department defined distribution transformer service life as the age at which the transformer retires from service. NEMA suggested that the Department use a transformer lifetime of 30 years for the LCC analysis. (NEMA, No. 7 at pp. 10–11) NEMA later suggested that DOE should investigate the actual lifetime of dry-type distribution transformers which it felt could be closer to 20 years, rather than the 32 years assumed in the Department's analysis. (NEMA, No. 26 at p. 3) CDA commented that it is not uncommon to find transformers 50-plus years old still in service. (CDA, No. 43 at p. 3)

The Department assumed, based on ORNL–6847, Determination Analysis of Energy Conservation Standards for Distribution Transformers, that the average life of distribution transformers is 32 years. After preparing an in-depth review of average lifetimes during the Determination Analysis, ORNL found it to be 32 years. The Department still believes this is an accurate representation of the average lifetime of a distribution transformer. This lifetime assumption includes a constant failure rate of 0.5 percent/year due to lightning and other random failures unrelated to transformer age and an additional corrosive failure rate of 0.5 percent/year at year 15 and beyond. The Department adjusted the retirement distribution to maintain an average life of 32 years for both liquid-immersed and dry-type transformers.

i. Maintenance Costs

The Department assumed that the cost for general maintenance of distribution transformers will not change with increased efficiency. In practice, there is little scheduled maintenance for distribution transformers. The maintenance that does occur normally consists of brief annual checks for dust buildup, vermin infestation, and accident or lightning damage.

j. Discount Rates

The discount rate is the rate at which future expenditures are discounted to estimate their present value. Stakeholders expressed concern over the appropriate discount rate to use in the LCC analysis. NEMA stated that 8 percent should be the minimum discount rate considered and that a discount range of 15–20 percent adjusted for inflation (real) would more closely reflect opportunity costs for business. (NEMA, No. 7 at p. 11) NEMA also suggested that the Department use a high hurdle rate of 35 percent for the LCC analysis. (NEMA, No. 26 at p. 2) Mr. John Ainscough also noted that DOE should consider the opportunity cost of capital that may be diverted from other areas to pay for more expensive transformers. (J. Ainscough, No. 15 at p. 1) NRDC stated that the 35 percent discount rate is unjustified, pointing out that this discount rate is evidence of the type of market failure that standards are supposed to address. (NRDC, No. 27 at p. 3) NRDC stated that an 8 percent discount rate is too high. NRDC noted that it has demonstrated in previous appliance rulemakings that market rates of return on investment are in the range of 5–5.5 percent real, at best. (NRDC, No. 5 at p. 4) NRDC stated that these are the highest rates that are defensible and recommended that the distribution of rates used for the analysis center around 2–3 percent real to reflect reduced societal risk resulting from energy efficiency standards. NRDC also stated that it agrees with the Department that the actual cost of capital represents the appropriate discount rate for the LCC analysis. (NRDC, No. 25 at p. 2 and No. 27 at p. 2) Cooper Power Systems commented that the discount rate selection method should be similar to that used by DOE to determine the present value of improved efficiency in other energy savings projects such as for refrigerators and motor efficiency. (Cooper Power Systems, No. 34 at p. 2)

Lacking stakeholder consensus, the Department used the classic economic definition that discount rates are equal to the cost of capital. The cost of capital is a combination of debt interest rates and the cost of equity capital to the affected firms and industries. For each design line, the Department divided ownership into classes of potential customers. Table II.10 shows the classes of owners and their percentages by design line. The Department determined from the Damodaran online investment survey *(http://pages.stern.nyu.edu/adamodar/)* that each class of potential owners has a distribution of discount rates. The discount rate distribution for each design line analyzed in the LCC analysis is a weighted sample that combines estimated ownership percentages based on the 2001 shipment estimates and their respective discount rates. Table II.10 also shows the mean real discount rates by ownership category used by DOE in the analysis. In addition, Table II.10 shows the resultant weighted average discount rates for each design line. A more detailed description of the data sources is provided in Chapter 8 of the TSD. As highlighted in section IV.E, the Department seeks input from stakeholders on the appropriateness of these discount rates.

TABLE II.10.—WEIGHTED AVERAGE DISCOUNT RATES BY DESIGN LINE AND OWNERSHIP CATEGORY

Mean real discount rate		Transformer ownership category					
Design line	Weighted average discount rate (percent)	Property owners	Industrial companies	Commercial companies	Investor-owned utilities	Publicly owned utilities	Government offices
		4.35%	7.55%	7.46%	4.16%	4.31%	3.33%
		Estimated ownership (%)					
1	4.24	0.4	0.5	0.9	72.0	26.0	0.2
2	4.24	0.4	0.5	0.9	72.0	26.0	0.2
3	4.40	2.1	2.4	4.5	80.0	10.0	1.0
4	4.24	0.4	0.5	0.9	72.0	26.0	0.2
5	5.38	9.5	9.5	27.0	35.0	15.0	4.0
6	6.56	19.0	19.0	54.0	0.0	0.0	7.9
7	6.56	19.0	19.0	54.0	0.0	0.0	7.9
8	6.56	19.0	19.0	54.0	0.0	0.0	7.9
9	6.56	19.0	19.0	54.0	0.0	0.0	7.9
10	6.56	19.0	19.0	54.0	0.0	0.0	7.9
11	6.56	19.0	19.0	54.0	0.0	0.0	7.9
12	6.56	19.0	19.0	54.0	0.0	0.0	7.9
13	6.56	19.0	19.0	54.0	0.0	0.0	7.9

3. Payback Period

A more energy efficient device will usually cost more to buy than a device of standard energy efficiency. But the more efficient device will usually cost less to operate due to the reductions in operating costs (*i.e.*, lower energy bills). The PBP is the time (usually expressed in years) it takes to recover the additional installed cost of the efficient device through energy cost savings. Payback analysis is a common technique used to evaluate investment decisions. Because the LCC analysis uses distributions of inputs to represent individual transformer purchases, results such as PBPs are given in the form of distributions.

The data inputs to the payback calculation are the purchase expense, otherwise known as the total installed consumer cost or ''first cost,'' and the annual operating costs for each selected design. The inputs to the purchase expense are the equipment price and the installation cost with appropriate markups. The inputs to the operating costs are the annual energy consumption and the electricity price. The payback calculation uses the same inputs as the LCC analysis but since this is a ''simple'' payback, the operating cost is for the year the standard takes effect, assumed here to be 2007.

4. Life-Cycle Cost and Payback Period Results

The following 13 tables (Table II.11 through Table II.23) present the findings from the Department's LCC analysis. For each evaluated design line and each candidate standard level, the Department presents the minimum efficiency candidate standard level, the percent of transformers that experience positive (or zero) LCC savings when subject to the standard level, the mean LCC savings, and the mean PBP. The Department presents these findings to facilitate stakeholder review of the LCC analysis. The Department has not selected any specific standard level for any design line. Graphical illustrations that provide a more comprehensive report of the LCC findings are available in Chapter 8 of the TSD. For each LCC analysis, candidate standard level 1 is equivalent to the efficiency level of NEMA TP 1–2002.

In the paragraph preceding each of the following 13 tables, the Department provides the average efficiency and the average manufacturer's selling price of the baseline transformers selected during the LCC analysis for each design line's representative unit. This average efficiency is the mean of the efficiencies of all the transformers selected under the baseline scenario. The Department selected a range of transformer designs according to customer A and B evaluation combinations in the baseline and candidate standard level scenarios. Some units selected have high efficiencies while others have low efficiencies. For three of the thirteen design lines (1, 3, and 5), the average efficiency of the baseline transformers is higher than the minimum efficiency selected for candidate standard level 1. While such a relationship might seem inappropriate, the Department notes that a direct comparison between the baseline average efficiency and the efficiency level chosen for any candidate standard is not meaningful. That is because the former value is an average efficiency of those transformers selected under baseline conditions while the latter value is the minimum efficiency for the selection of transformer designs meeting a candidate standard level.

Table II.11 presents the summary of the LCC and PBP analyses for the representative unit from design line 1, a 50 kVA, liquid-immersed, single-phase, pad-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.91 percent and the average manufacturer's selling price was $1,580.

TABLE II.11.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 1 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.90	99.10	99.30	99.40	99.58
Transformers having LCC Savings ≥ $0 (%)	99.5	86.3	41.4	35.8	13.1
Mean LCC Savings ($)	134	158	−13	−64	−359
Mean Payback (Years)	6.3	14.5	25.1	23.3	32.5

Table II.12 presents the summary of the LCC and PBP analyses for the representative unit from design line 2, a 25 kVA, liquid-immersed, single-phase, pole-mounted transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.59 percent and the average manufacturer's selling price was $950.

TABLE II.12.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 2 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.70	98.90	99.10	99.30	99.47
Transformers having LCC Savings ≥ $0 (%)	99.7	66.7	26.8	13.7	2.8
Mean LCC Savings ($)	99	62	−76	−216	−492
Mean Payback (Years)	5.8	21.7	30.3	29.7	40.7

Table II.13 presents the summary of the LCC and PBP analyses for the representative unit from design line 3, a 500 kVA, liquid-immersed, single-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.33 percent and the average manufacturer's selling price was $4,599.

TABLE II.13.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 3 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	99.30	99.40	99.60	99.70	99.75
Transformers having LCC Savings ≥ $0 (%)	96.5	97.5	70.3	68.9	52.1
Mean LCC Savings ($)	884	1,606	1,168	1,838	1,292
Mean Payback (Years)	8.2	8.3	16.9	18.1	23.6

Table II.14 presents the summary of the LCC and PBP analyses for the representative unit from design line 4, a 150 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.86 percent and the average manufacturer's selling price was $3,577.

TABLE II.14.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 4 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.90	99.10	99.30	99.40	99.56
Transformers having LCC Savings ≥ $0 (%)	97.5	90.9	73.7	75.9	50.8
Mean LCC Savings ($)	574	733	491	585	301
Mean Payback (Years)	7.7	12.1	16.5	16.2	24.7

Table II.15 presents the summary of the LCC and PBP analyses for the representative unit from design line 5, a 1500 kVA, liquid-immersed, three-phase distribution transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 99.35 percent and the average manufacturer's selling price was $11,088.

TABLE II.15.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 5 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	99.30	99.40	99.50	99.60	99.66
Transformers having LCC Savings ≥ $0 (%)	97.8	97.2	80.2	78.5	64.4
Mean LCC Savings ($)	4,174	6,617	7,451	7,268	6,838
Mean Payback (Years)	6.2	6.7	13.4	13.4	17.7

Table II.16 presents the summary of the LCC and PBP analyses for the representative unit from design line 6, a 25 kVA, low-voltage, dry-type, single-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 95.36 percent and the average manufacturer's selling price was $864.

TABLE II.16.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 6 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.00	98.20	98.40	98.70	98.79
Transformers having LCC Savings ≥ $0 (%)	99.3	99.1	99.1	94.1	92.8
Mean LCC Savings ($)	1,777	1,865	1,948	1,906	1,867
Mean Payback (Years)	1.7	2.6	2.6	5.6	6.7

Table II.17 presents the summary of the LCC and PBP analyses for the representative unit from design line 7, a 75 kVA, low-voltage, dry-type, three-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 96.43 percent and the average manufacturer's selling price was $1,808.

TABLE II.17.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 7 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.00	98.30	98.60	98.90	99.09
Transformers having LCC Savings ≥ $0 (%)	100.0	99.0	98.4	88.8	77.5
Mean LCC Savings ($)	3,156	3,588	3,927	3,910	3,799
Mean Payback (Years)	0.6	2.6	3.5	7.1	10.8

Table II.18 presents the summary of the LCC and PBP analyses for the representative unit from design line 8, a 300 kVA, low-voltage, dry-type, three-phase transformer. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.79 percent and the average manufacturer's selling price was $4,735.

TABLE II.18.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 8 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.60	98.80	99.00	99.20	99.27
Transformers having LCC Savings ≥ $0 (%)	99.8	97.8	96.6	92.1	89.4
Mean LCC Savings ($)	6,761	7,035	7,899	8,941	8,712
Mean Payback (Years)	1.0	2.9	4.5	6.5	7.4

Table II.19 presents the summary of the LCC and PBP analyses for the representative unit from design line 9, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 45 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.90 percent and the average manufacturer's selling price was $6,084.

TABLE II.19.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 9 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.60	98.80	99.00	99.20	99.31
Transformers having LCC Savings ≥ $0 (%)	95.8	93.4	95.2	84.6	70.0
Mean LCC Savings ($)	6,465	7,550	8,536	8,942	7,838
Mean Payback (Years)	4.8	6.1	5.7	8.9	13.1

Table II.20 presents the summary of the LCC and PBP analyses for the representative unit from design line 10, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 45 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.63 percent and the average manufacturer's selling price was $22,473.

TABLE II.20.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 10 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	99.10	99.20	99.30	99.40	99.44
Transformers having LCC Savings ≥ $0 (%)	89.9	90.5	90.0	72.1	64.5
Mean LCC Savings ($)	14,458	16,130	18,050	15,594	13,704
Mean Payback (Years)	8.5	8.5	8.9	13.9	15.6

Table II.21 presents the summary of the LCC and PBP analyses for the representative unit from design line 11, a 300 kVA, medium-voltage, dry-type, three-phase transformer with a 95 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 97.77 percent and the average manufacturer's selling price was $10,142.

TABLE II.21.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 11 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	98.50	98.70	98.90	99.00	99.10
Transformers having LCC Savings ≥ $0 (%)	96.4	94.9	87.4	75.6	68.0
Mean LCC Savings ($)	4,473	5,350	5,734	5,136	4,666
Mean Payback (Years)	5.8	6.7	9.3	12.5	14.3

Table II.22 presents the summary of the LCC and PBP analyses for the representative unit from design line 12, a 1500 kVA, medium-voltage, dry-type, three-phase transformer with a 95 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.67 percent and the average manufacturer's selling price was $26,542.

TABLE II.22.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 12 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	99.00	99.10	99.30	99.40	99.45
Transformers having LCC Savings ≥ $0 (%)	91.5	85.8	84.6	71.0	59.6
Mean LCC Savings ($)	8,369	12,318	15,390	14,365	11,341
Mean Payback (Years)	8.0	9.6	10.7	14.2	17.1

Table II.23 presents the summary of the LCC and PBP analyses for the representative unit from design line 13, a 2000 kVA, medium-voltage, dry-type, three-phase transformer with a 125 kV BIL. For this unit, the average efficiency of the baseline transformers selected during the LCC analysis was 98.73 percent and the average manufacturer's selling price was $37,082.

TABLE II.23.—SUMMARY OF LCC & PBP RESULTS FOR THE DESIGN LINE 13 REPRESENTATIVE UNIT

	Candidate standard level				
	1	2	3	4	5
Minimum Efficiency (%)	99.00	99.10	99.30	99.40	99.45
Transformers having LCC Savings ≥ $0 (%)	92.0	90.6	76.9	77.6	44.9
Mean LCC Savings ($)	11,691	16,119	16,685	19,706	7,593
Mean Payback (Years)	6.7	8.5	12.7	12.7	20.3

G. Shipments Analysis

This section presents the Department's shipments analysis, which is a key input into the national impact analysis (section II.H). Additional detail on the shipments analysis can be found in Chapter 9 of the TSD.

1. Shipments Model

The shipments model combines the shipments estimates for 2001, transformer quantity indices from the U.S. Bureau of Economic Analysis (BEA), electricity market shares from DOE's Energy Information Administration (EIA), and equipment price estimates from the LCC to project transformer shipments. The shipments model produces both a backcast (an estimate backwards in time) and a forecast of total shipments. The shipments forecast and a retirement function are used to calculate in-service transformer age distribution, and estimate the proportion of transformers in-service impacted by candidate standard levels and transformer retirements. The Department determines the number of transformers manufactured to satisfy new electrical capacity by subtracting transformer retirements from total shipments.

Distribution transformer shipment estimates are also used as an input to the MIA. That analysis, which DOE will undertake after the ANOPR is published, will estimate the impacts of potential efficiency standards on manufacturers. The Department will report the findings of the MIA in the NOPR.

The Department considered several approaches to developing an estimate of the shipments of distribution transformers in 2001. Manufacturers consider annual shipment information extremely sensitive, and several manufacturers who met with the Department in early 2002 indicated they would not be able to provide this data, even under a confidentiality agreement with one of the Department's contractors. Furthermore, the Department recognizes that there are more than 100 manufacturers supplying distribution transformers to the U.S. market. It would be difficult to prepare an estimate on a company-by-company basis.

To resolve this impasse for this specific data gap, the Department contracted a third-party, HVOLT, only to prepare a shipments estimate. This contractor developed an estimate of distribution transformer shipments in 2001 by constructing a market participation matrix incorporating manufacturers and their product lines. HVOLT then populated this matrix based on its knowledge of the industry and a limited number of confidential interviews with key manufacturers and users. These estimates were rolled-up and then given to the Department as national aggregate shipment totals for each of the 115 kVA ratings (see Tables 9.3.2 through 9.3.4 in TSD Chapter 9).

Table II.24 presents the shipment estimates in both units shipped and megavolt-amperes (MVA) shipped, and the approximate value of these shipments, showing that the distribution transformer industry totaled about $1.6 billion dollars in 2001 (2001 dollars).

TABLE II.24.—NATIONAL DISTRIBUTION TRANSFORMER SHIPMENT ESTIMATES FOR 2001

Distribution transformer product class	Units shipped	MVA capacity shipped	Shipment value ($million)
1. Liquid-immersed, medium-voltage, single-phase	977,388	36,633	698.8
2. Liquid-immersed, medium-voltage, three-phase	79,367	42,887	540.4
3. Dry-type, low-voltage, single-phase	23,324	983	17.8
4. Dry-type, low-voltage, three-phase	290,818	21,909	235.0
5. Dry-type, medium-voltage, single-phase, 20–45 kV BIL	119	18	0.5
6. Dry-type, medium-voltage, three-phase, 20–45 kV BIL	650	776	13.5
7. Dry-type, medium-voltage, single-phase, 46–95 kV BIL	121	22	0.6
8. Dry-type, medium-voltage, three-phase, 46–95 kV BIL	2,371	3,913	68.1
9. Dry-type, medium-voltage, single-phase, ≥96 kV BIL	20	4	0.1
10. Dry-type, medium-voltage, three-phase, ≥96 kV BIL	187	367	6.4
Total	1,374,366	107,512	1,581.2

The Department used the forecasts of shipments for the base case and the standards case to provide an estimate of the annual sales and number of transformers in-service in any given year during the forecast period. The estimate includes the age distribution of transformers for each transformer type (classified according to product classes). The Department used annual transformer sales to calculate equipment costs for the NPV and the age distribution of the transformers in-service to calculate the energy use for the NES. The Department chose an accounting model method to prepare shipment scenarios for the base case and the candidate standard level cases. The model keeps track of the aging and replacement of transformer capacity given a projection of future transformer sales growth.

Shipments are organized into two categories: replacements and new capacity. Replacements occur when old transformers break down, corrode, are struck by lightning, or otherwise need to be replaced. New capacity purchases occur due to increases in electricity use that may be driven by increasing population, increasing commercial and industrial activity, or growth in electricity distribution systems. The model starts with an estimate of the national growth in cumulative transformer capacity to estimate total shipments. The model then divides the total shipments into liquid-immersed and dry-type transformers using their respective market shares estimated from electricity consumption data. The liquid-immersed and dry-type transformers are further divided into their respective product classes using estimates of the relative market share for different design and size categories. Seven modeling steps are performed as follows:

- In the data collection step, the Department acquires and processes information on transformer shipments.
- The construction of an aggregate shipments backcast uses shipments and electricity consumption data to provide an estimate of historical total annual capacity shipped.
- The construction of an aggregate shipments forecast applies a shipments growth rate to provide a base case annual-shipments estimate for the future.
- The liquid-immersed and dry-type market share estimate divides the total capacity shipped into liquid-immersed and dry-type transformers.
- The modeling of the purchase price elasticity provides an estimate of how higher purchase prices due to a candidate standard level can impact the future capacity shipped.
- The accounting of transformer sales and quantity in-service uses the shipments estimates and a retirement function to derive an annual age distribution of transformers in-service.
- A final consistency check confirms that the estimates of the shipments model are consistent with available data on utility transformer purchases and replacements.

The following section describes the inputs to the shipments model at different stages of the calculation. The Department welcomes suggestions from stakeholders for improving the data inputs to the model.

2. Shipments Model Inputs

The shipments model inputs correspond closely to the steps of the shipments calculation described in the previous section. Some inputs come from outside the shipments calculations, while other inputs for later stages of the calculation are intermediate results calculated from earlier inputs. The final outputs of the shipments calculation are the annual shipments estimates and the annual estimates of the age distribution of transformers in-service.

Table II.25 presents a summary of these shipments model inputs. Chapter 9 of the TSD contains a detailed description of all the shipments model inputs.

TABLE II.25.—SUMMARY OF SHIPMENTS MODEL INPUTS

Input	Description
Shipments data	Third party expert (HVOLT) for the year 2001.
Shipments backcast	For years 1977–2000: Used BEA's manufacturing data for distribution transformers. Source: http://www.bea.doc.gov/bea/pn/ndn0304.zip. For years 1950–1976: Based on EIA's electricity sales data. Source: http://www.eia.doe.gov/emeu/aer/txt/stb0805.xls.
Shipments forecast	Years 2002–2035: Based on *AEO 2003.*
Dry-type/liquid-immersed market shares	Based on EIA's electricity sales data and *AEO 2003.*
Regular replacement market	Based on a survival function constructed from a Weibull distribution function normalized to produce a 32-year mean lifetime. Source: ORNL 6804/R1, The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance, page D–1.
Elasticities	For liquid-immersed transformers: • Low: 0.00 • Medium: −0.04 • High: −0.20 For dry-type transformers: • 0.00

The Department determined the price elasticities for liquid-immersed transformers by calibrating a model employing a standard econometric logit equation, fit to FERC Form No. 1 data. The fit resulted in a price elasticity of −0.04, which the Department used as the ''medium'' scenario. For a ''high'' sensitivity to price change scenario, DOE used an elasticity of −0.20. The ''low'' scenario used zero elasticity or no impact in purchase decisions from a price change.

Total shipments depend on assumptions regarding the lifetime of a distribution transformer and the growth in new electricity demand. For consistency with the LCC, the Department used the same 32-year average lifetime.

3. Shipments Model Results

The main output of the shipments model is the total capacity of distribution transformers shipped in each year from 2007 through 2035. Total shipments for all CSLs for liquid-immersed and dry-type distribution transformers are shown in Table II.26.

TABLE II.26.—CUMULATIVE TRANSFORMER SHIPMENTS BETWEEN 2007–2035 BY CANDIDATE STANDARD LEVEL

Distribution transformers	Transformer capacity shipments in billion kVA					
	Base case	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
Liquid-immersed	3.06	3.06	3.05	3.04	3.03	3.01
Dry-type	1.23	1.23	1.23	1.23	1.23	1.23

The biggest factor that influences the size of the potential standards-induced change in shipments is the actual equipment price increase due to standards. The Department assumed price impacts only for liquid-immersed transformers. If price increases are large, the shipments volume decreases almost proportionally to the price increase, but because the price elasticity of liquid-immersed transformers is less than one, price increases result in increased gross sales dollar volume to the transformer manufacturer. The Department will examine the net financial impact of these opposing effects in more detail in the MIA.

H. National Impact Analysis

This section presents the methodology and structure the Department used to implement the national impact analysis. This analysis assessed future NES from candidate transformer standards as well as the national economic impacts using the NPV metric. Additional detail is found in Chapter 10 of the TSD.

The NES is the cumulative incremental energy savings from a transformer efficiency standard relative to a base case of no national standard over a forecast period that ends in the year 2035. The Department calculated the NES for each candidate standard level in units of quadrillion (quads) Btus (British thermal units) for standards assumed to be implemented in the year 2007. The NES calculation started with transformer shipments and quantity in-service from the shipments model. The Department calculated total energy use by transformers in-service using estimates of transformer losses from the LCC analysis, for each year for both a base case and a candidate standards case.

Over time, in the standards case, more efficient transformers gradually replace less efficient ones. Thus, the energy per unit capacity used by transformers in-service gradually decreases in the standards case relative to the base case. The Department converted the site energy used by the transformers into the amount of energy consumed at the source of electricity generation (the source energy) with a site-to-source conversion factor. The site-to-source factor accounts for transmission, distribution, and generation losses. For each year analyzed, the difference in source energy use between the base case and standard scenario is the annual energy savings. The Department summed the undiscounted annual energy savings from 2007 through 2035 to calculate the total NES for the forecast period. The NES analysis which will accompany the NOPR will include both undiscounted and discounted values for future energy savings to account for their timing.

The NPV is the net present value of the incremental economic impacts of a candidate standard levels. The Department calculated the NPV in a way that is similar to the NES, except that incremental costs are estimated instead of energy, and the net costs are discounted rather than calculated as an undiscounted sum. Like the NES, the NPV calculation started with transformer shipments and quantity in-service from the shipments model. Using estimates of transformer installed costs, losses, and electricity costs from the LCC analysis, the Department calculated the national expenditures for installed transformer purchases and the corresponding operating costs of the transformers in-service for each year for both a base case and standards case.

Over time, in the standards case, transformers that are both more expensive and more efficient gradually replace less efficient transformers. Thus, the operating cost per unit capacity used by the transformers in-service gradually decreases in the standards case relative to the base case, while the equipment costs increase. The Department discounted purchases and expenses and operating costs for transformers using a national average discount factor as described in Chapter 10 of the TSD. The Department calculated the NPV impact of transformers that will be bought between 2007 and 2035.

To make the analysis more accessible to all stakeholders, the Department prepared a national impact spreadsheet model (available on the Department's website) in Microsoft Excel to execute the calculations outlined above. The spreadsheet calculates capacity and operating cost savings associated with each of the candidate standard levels. The NES analysis considers cumulative energy savings through the year 2035, while the NPV considers capacity and operating cost savings through the year 2070 [3] for transformers bought on or before 2035. By taking the difference between the base case and candidate standard levels, summing, and discounting the annual results, the spreadsheet calculates an NPV for each candidate standard level relative to the base case.

1. Method

Both calculations start by using the estimate of shipments and quantity in-service that resulted from the shipments model (section II.G) and then proceed with the NES and NPV calculations. Key inputs from the LCC analysis are the average rated losses for both no-load and load losses, and the equipment cost of transformers, including installation. The losses and the equipment costs then go through a transformer size and product class adjustment that converts the data from representative design lines to average product class information. Additional inputs regarding average and peak losses—including root mean square (RMS) loading, peak loading, and peak responsibility factor—allow a calculation of losses from rated losses at rated loading. At this point, the information flow for the NES and NPV calculation splits into two paths.

On one path, the NES calculation sums the actual losses and the affected in-service transformers, and takes the difference between the base case and standards scenarios to calculate site energy savings. The conversion of site energy savings to energy savings at the source (*i.e.*, at the power plant), is calculated by the National Energy Modeling System (NEMS). The sum of annual energy savings for the forecast period through 2035 then provides the final NES number.

On the other path, the NPV calculation brings in marginal price inputs from the LCC analysis for both energy costs and capacity costs and for both load losses and no-load losses. The marginal prices, when combined with the actual peak and average losses, provide an estimate of the operating cost. Meanwhile, the equipment installed cost multiplied by the annual shipments provides an estimate of the total annual equipment costs. The Department then takes three differences to calculate the net impact of the candidate standard levels. The first difference is between the candidate standard level scenario equipment costs and the base case equipment costs to get the net equipment cost increase from a candidate standard level. The second difference is between the base case operating cost and the candidate standard level operating cost to get the net operating cost savings from a candidate standard level. And the third difference is between the net operating cost savings and the net equipment cost increase to get the net savings (or expense) for each year. The net savings (or expense) is then discounted and summed to the year 2070 for transformers bought on or before 2035 to provide the NPV impact of a candidate standard level.

Table II.27 summarizes the inputs used to calculate the NES and NPV of the various candidate standard levels. A more detailed discussion of the inputs follows the table.

TABLE II.27.—SUMMARY OF NES AND NPV INPUTS

Input	Description
Shipments	Annual shipments from shipments model (*see* details in section II.G.
Effective Date of Standard	Assumed here to be 2007.
Base Case Efficiencies	Constant efficiency through 2035. Equal to weighted-average efficiency in 2007.
Standards Case Efficiencies (2007–2035)	Constant efficiency at the specified standard level from 2007–2035.
Annual Energy Consumption per Unit	Average rated transformer losses are obtained from the LCC analysis, which are then scaled for different size categories, weighted by size market share, adjusted for transformer loading (also obtained from the LCC analysis).
Total Installed Cost per Unit	Weighted-average values as a function of efficiency level (from LCC analysis).

[3] The year 2070 is the rounded sum of 2035 plus 32 years, the average lifetime of distribution transformers.

TABLE II.27.—SUMMARY OF NES AND NPV INPUTS—Continued

Input	Description
Electricity Expense per Unit	Both energy and capacity savings for the two types of transformer losses are multiplied by the average marginal costs for both capacity and energy for the two types of losses (marginal costs are from the LCC analysis).
Escalation of Electricity Prices	*AEO 2003* forecasts (to 2025) and extrapolation for 2035 and beyond (*see* LCC discussion, section II.F).
Electricity Site-to-Source Conversion	A time series conversion factor; includes electric generation, transmission, and distribution losses. Conversion varies yearly and is generated by DOE/EIA's National Energy Modeling System program.
Discount Rates	3% and 7% real.
Analysis Year	Future expenses are discounted to the year of equipment price data, 2001.

The Department provides detailed descriptions of the NES and NPV models below. It provides a descriptive overview of how the Department performed each model's calculations, and follows with a summary of the inputs. Chapter 10 of the TSD contains full technical descriptions of these models and their inputs, processes (with equations, when appropriate), and outputs. After the model descriptions, the Department presents the summary results of the national impacts calculations.

2. National Energy Savings

The Department developed a method to calculate national energy savings resulting from different candidate distribution transformer efficiency standards—the NES. Positive NES values correspond to net energy savings, that is, a decrease in energy consumption with standards in comparison to the energy consumption in a base case.

The Department received a comment from TXU Electric and Gas that energy savings must be tempered with a more comprehensive look at the effects of producing more efficient transformers. TXU Electric and Gas stated that to increase the distribution transformer efficiency there might be a 50 percent increase in production of higher quality core steel and a 30 percent increase in the use of transformer oil in each unit. These products require energy to produce or refine. The production of the core steel is environmentally ''dirty.'' The costs associated with increased energy usage and the environmental impacts of production of higher efficiency transformers should be considered in the cost effectiveness of the improved efficiency. (TXU Electric and Gas, No. 12 at p. 8)

In evaluating and establishing energy efficiency standards, the Department does not presently consider the wide range of externalities associated with the production of higher efficiency products or equipment—in this case, distribution transformers. The difficulties and uncertainties associated with analyzing those externalities would substantially increase the complexity of standards rulemakings and potentially lessen the reliability of their ultimate outcomes. Therefore, in calculating increased costs associated with standards, DOE's current methodology is limited to using the transformer manufacturers' estimated costs of producing more efficient transformers.

a. National Energy Savings Overview

The Department calculated the cumulative incremental energy savings in units of quadrillion Btus (quads) from candidate transformer efficiency standards relative to a base case of no standard over a forecast period that spans the first standards years from 2007 to 2035.

NEMA submitted a comment addressing how the Department should characterize the baseline condition against which energy savings for various candidate standard levels are calculated. In particular, NEMA commented that in principle, the NES analysis should use the same inputs as the LCC analysis. NEMA considered market penetration of more efficient transformers without regulations to be a key aspect of the NES and noted that multiple base case scenarios may be needed. (NEMA, No. 7 at p. 12) Consistent with NEMA's comment, the Department used a range of purchaser valuations given to transformer no-load and load losses, expressed as A and B distributions, to represent customer choice scenarios as noted in section II.F.2.c.

The shipments model provides the estimate for the affected in-service transformers. The key to the NES calculation is in measuring the difference in energy per unit capacity between the standards case and the base case, given the input from the LCC and including the site-to-source conversion factor that translates site energy into energy consumed at the power plant. The next section summarizes the inputs necessary for the NES calculation. The Department welcomes suggestions from stakeholders for possible data enhancements in the NES inputs.

b. National Energy Savings Inputs

The NES model inputs fall into three broad categories: (1) Those that help convert the data from the LCC into data for the product classes and transformer size distributions used in the NES; (2) those that help calculate the unit energy consumption; and (3) site-to-source factors that enable the calculation of source energy consumption from site energy use.

The size scaling of losses and costs adjusts LCC representative design line data so it can represent the size distribution of transformers that are in a particular product class. The mapping of LCC design line data to product classes (Table II.5) provides the proper inter-design line averaging or adjustments for representation of the product classes.

The RMS loading is a key factor in estimating actual load losses given the load losses at rated load for a transformer. Load growth over the lifetime of the transformer can change the average RMS loading experienced by affected transformers. The effective date of the standard impacts the definition of the affected transformers. The unit energy consumption is the energy per unit capacity of an affected transformer and depends on all of the first four inputs.

The electricity site-to-source conversion provides the estimate of energy consumption at the generation station given the energy use at the site of the transformer. Finally, the affected transformers are those in-service transformers that may have different characteristics as a result of a candidate standard level.

The Department received comments from stakeholders on the loading level appropriate for measuring national energy savings. In particular, NEMA commented that it would be appropriate to do sensitivity analysis comparisons at different loading levels, but that the primary economic analyses on which a standard is based should be done using the TP 1 load levels of 35 percent and 50 percent. NEMA noted that it may also be appropriate to calculate national energy savings based on lower loading. NEMA stated that it does not think it is prudent to base standards on lower load levels. NEMA went on to say that many large transformers are used to supply power for continuous, 24-hour industrial processes that have high load factors. Examples of these applications are chemical companies, oil refineries, steel mills, grain refineries, and copper and aluminum manufacturers. NEMA stated that any analysis that establishes standards based on lower load factors will unduly penalize these industries, and not result in actual maximum energy savings. (NEMA, No. 7 at p. 10)

Howard Industries, Inc. noted that since utilities will be forced to adopt the DOE rule, they will likely drop the TOC approach of evaluating distribution transformers with the result that often they may end up buying less efficient transformers. However, in other cases, to meet the threshold efficiency of the rule, utilities may have to pay more for their transformers even though they are not economically justified, and therefore the DOE rule will not be good for the environment because more energy will be needed to supply these increased losses. Howard Industries argued that these points should be taken into consideration when the DOE makes its new NES analysis. (Howard Industries, No. 4 at p. 2)

The Department has taken these comments into consideration in the NES calculations, which use loading, costs, and losses as inputs from the LCC analysis. (TSD Chapter 8)

Table II.28 summarizes the various inputs and sources of the distribution transformer NES calculations.

TABLE II.28.—SUMMARY OF INPUTS FOR NES CALCULATIONS

Input	Description
Size scaling of losses and costs	The “0.75 rule” applied to the losses and costs from the LCC analysis.
Mapping of design lines to product classes	Table II.5 shows the mapping of the 13 engineering design lines to the 10 product classes.
Root mean square loading	From the LCC analysis.
Annual Load growth	1% for the liquid-immersed and 0% for the dry-type transformers.
Effective date of standard	Three years after publication of the Final Rule.
Unit energy consumption	Based on losses and RMS loading and the load growth.
Site-to-source electricity conversion	A time series conversion factor; includes electric generation, transmission, and distribution losses. Conversion varies yearly and is generated by the NEMS program.
Affected transformers	From the shipments model.

To determine product class characteristics from design line estimates, the Department first scaled characteristics by transformer capacity to determine per kVA characteristics. Then the Department calculated shipment-weighted averages of per kVA characteristics of the appropriate design lines to get the per kVA characteristics of the product classes. The Department's contractor provided the capacity shipped for each design line (and each product class), the LCC analysis provided the economic results for each design, and the 0.75 Scaling Rule provided the re-scaled cost and loss estimates for each size category represented with a given design line. For no-load losses, no more adjustment is needed; but for load losses, the losses at rated load need to be converted to losses at actual loading. The RMS loading is a key factor in estimating load losses at actual loading. Thus, the load losses are particularly sensitive to the RMS loading.

3. Net Present Value Calculation

The Department takes into consideration the national financial impact from the imposition of new energy efficiency standards, which is expressed as the national NPV. The output of the shipments model is combined with energy savings and financial data from the LCC to calculate an annual stream of costs and benefits resulting from candidate distribution transformer energy efficiency standards. This time series is discounted to 2001 and summed, resulting in the national NPV. The Department selected 2001 as the NPV analysis year, for consistency with the year of equipment price data used in the analysis. A different NPV analysis year may be used in the NOPR.

a. Net Present Value Overview

The NPV is the present value of the incremental economic impacts of a candidate standard level. Mathematically, NPV is the present value in a time series of costs and savings occurring in the future. The Department calculated net savings each year as the difference between total operating cost savings (both energy and electricity system capacity) and increases in total installed costs (including equipment price and installation cost). Electricity system capacity costs include generation, transmission and distribution. Savings were calculated over the life of the equipment, which takes into account the differences in yearly energy rates. The Department calculated the NPV as the difference between the present value of operating cost savings and the present value of increased total installed costs. It discounted purchases and expenses and operating costs for transformers using national average discount factors, which the Department calculated from the discount rate and the number of years between 2001 (the year to which DOE discounted the sum) and the year in which the costs and savings occur. An NPV greater than zero indicates net savings (*i.e.*, the energy efficiency standard reduces customer expenditures in the standards case relative to the base case). An NPV less than zero indicates that the energy efficiency standard creates net costs to consumers.

The following section outlines the inputs specific to the NPV calculation. The Department welcomes suggestions from stakeholders for improving these.

b. Net Present Value Inputs

The NPV model inputs include cost inputs, selected inputs that are important for detailing electricity capacity costs, and several of the inputs used for the NES calculation. This section presents those inputs that have not yet been described as part of the shipments and NES models. Table II.29 summarizes these inputs.

TABLE II.29.—SUMMARY OF INPUTS FOR NPV CALCULATIONS

Input	Description
First cost (installed)	All of the initial costs that are incurred with the installation of a transformer.
Operating cost	Annual cost of operating a transformer including both energy and capacity costs for supplying no-load and load losses.
Peak responsibility factor (PRF)	The square of the ratio of the transformer load during peak divided by the annual peak transformer load. PRF is used to calculate the load loss peak coincidence factor for system capacity cost and demand cost estimates.
Initial peak load	The peak load of the transformer at the time of installation.
Electricity price forecast scalar	The ratio that scales the forecasted increase or decrease in electricity price over the period from 2001 to 2070.
Marginal electricity costs	The cost for the last kWh of electricity purchased.
Discount rates	The time value of money used by the Department to estimate the present value of a future monetary cost or benefit, 3% and 7% real.

The Department received several comments from stakeholders on the appropriate discount rate to use in the NPV calculation. Cooper Power Systems noted that another concern is the uncertainty regarding the appropriate interest rate to select for the present value evaluations. If the rate is skewed too high, lower efficiency units will be evaluated more favorably and vice versa. Cooper stated that a value as high as 35 percent cannot be justified today. Cooper stated that they would like to see how the interest rates are to be chosen. (Cooper Power Systems, No. 34 at p. 1)

NEMA commented that a discount rate representative of real world commercial and industrial business choices should be used. NEMA believes that the 8 percent real as suggested at the Department's framework document workshop is the minimum rate that should be considered. NEMA believes more appropriate discount rates would be in the range of 15 to 20 percent real. (NEMA, No. 7 at p. 11)

The Department estimated national impacts with both a 3 percent and a 7 percent real discount rate in accordance with the Office of Management and Budget's (OMB) guidelines contained in Circular A–4, Regulatory Analysis, September 17, 2003 (see Chapter 10 of the TSD).

4. National Energy Savings and Net Present Value Results

The following seven tables (Tables II.30 through II.36) present the findings from the Department's national impacts analysis. For each evaluated product class and each candidate standard level, the Department presents the NES in quads and the NPV in billions of dollars. Table II.30 provides a summary of the total analysis, grouping together all the liquid-immersed product classes and all the dry-type product classes. Tables II.31 and II.34 provide NPV results for liquid-immersed and dry-type product classes respectively using a 3 percent real discount rate. Tables II.32 and II.35 provide NPV results for the same product classes, using the 7 percent real discount rate. The Department presents all these findings to facilitate stakeholder review of the national impact analysis. The Department has not selected any specific standard level for any product class. A more comprehensive report of the national impact analysis findings is provided in Chapter 10 of the TSD.

a. National Energy Savings and Net Present Value From Candidate Standard Levels

Preliminary NES and NPV results from the NES spreadsheet model for CSL 1 through CSL 5 are shown in Table II.30. Tables II.31 through II.33 present NPV and NES results for liquid-immersed transformers by product class. Tables II.34 through II.36 present NPV and NES results for dry-type transformers by product class. The NPV results are reported using both a 3 percent and a 7 percent real discount rate. The NES is reported in quads, representing a quadrillion (10^{15}) Btus of avoided primary energy consumption at the power plant.

TABLE II.30.—SUMMARY OF CUMULATIVE NES AND NPV IMPACTS BETWEEN 2007–2035

Distribution transformers	Analysis	Candidate standard level				
		CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
Liquid-immmersed	NES (quads)	1.88	3.02	5.20	6.98	7.87
	NPV (billion 2001$, 3%)	6.50	8.32	6.45	5.16	−0.71
	NPV (billion 2001$, 7%)	1.67	1.51	−1.21	−3.18	−7.37
Dry-type	NES (quads)	4.98	5.75	6.71	7.46	8.18
	NPV (billion 2001$, 3%)	32.83	37.24	41.95	43.80	44.45
	NPV (billion 2001$, 7%)	10.09	11.27	12.39	12.26	11.41

TABLE II.31.—NET PRESENT VALUE BETWEEN 2007–2035: LIQUID-IMMERSED PRODUCT CLASSES, 3% REAL DISCOUNT RATE

Product class	Net present value ($ billions)				
	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
1. Liquid-immersed, medium-voltage, single-phase	3.05	3.21	0.60	−1.05	−6.87
2. Liquid-immersed, medium-voltage, three-phase	3.45	5.11	5.86	6.21	6.17
Total	6.50	8.32	6.45	5.16	−0.71

TABLE II.32.—NET PRESENT VALUE BETWEEN 2007–2035: LIQUID-IMMERSED PRODUCT CLASSES, 7% REAL DISCOUNT RATE

Product class	Net present value ($ billions)				
	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
1. Liquid-immersed, medium-voltage, single-phase	0.80	0.34	−1.88	−3.77	−7.22
2. Liquid-immersed, medium-voltage, three-phase	0.87	1.17	0.68	0.59	−0.15
Total	1.67	1.51	−1.21	−3.18	−7.37

TABLE II.33.—NATIONAL ENERGY SAVINGS BETWEEN 2007–2035: LIQUID-IMMERSED PRODUCT CLASSES

Product class	Cumulative primary energy savings (quads)				
	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
1. Liquid-immersed, medium-voltage, single-phase	0.97	1.53	2.70	4.10	4.43
2. Liquid-immersed, medium-voltage, three-phase	0.92	1.48	2.51	2.87	3.44
Total	1.88	3.02	5.20	6.98	7.87

TABLE II.34.—NET PRESENT VALUE BETWEEN 2007–2035: DRY-TYPE PRODUCT CLASSES, 3% REAL DISCOUNT RATE

Product class	Net present value ($ billions)				
	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
3. Dry-type, low-voltage, single-phase	2.36	2.55	2.61	2.67	2.70
4. Dry-type, low-voltage, three-phase	29.14	32.99	37.07	38.85	39.68
5. Dry-type, medium-voltage, single-phase, 20–45 kV BIL	0.0073	0.0084	0.0099	0.0102	0.0098
6. Dry-type, medium-voltage, three-phase, 20–45 kV BIL	0.32	0.36	0.42	0.42	0.40
7. Dry-type, medium-voltage, single-phase, 46–95 kV BIL	0.0055	0.0070	0.0087	0.0087	0.0084
8. Dry-type, medium-voltage, three-phase, 46–95 kV BIL	0.93	1.24	1.71	1.73	1.63
9. Dry-type, medium-voltage, single-phase, ≥96 kV BIL	0.0008	0.0012	0.0013	0.0016	0.0012
10. Dry-type, medium-voltage, three-phase, ≥96 kV BIL	0.09	0.13	0.14	0.17	0.12
Total	32.83	37.24	41.95	43.80	44.45

TABLE II.35.—NET PRESENT VALUE BETWEEN 2007–2035: DRY-TYPE PRODUCT CLASSES, 7% REAL DISCOUNT RATE

Product class	Net present value ($ billions)				
	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
3. Dry-type, low-voltage, single-phase	0.71	0.75	0.77	0.75	0.74
4. Dry-type, low-voltage, three-phase	9.03	10.07	11.07	11.04	10.37
5. Dry-type, medium-voltage, single-phase, 20–45 kV BIL	0.0021	0.0023	0.0027	0.0025	0.0021
6. Dry-type, medium-voltage, three-phase, 20–45 kV BIL	0.08	0.09	0.11	0.09	0.07
7. Dry-type, medium-voltage, single-phase, 46–95 kV BIL	0.0019	0.0023	0.0025	0.0021	0.0019
8. Dry-type, medium-voltage, three-phase, 46–95 kV BIL	0.25	0.32	0.41	0.34	0.24
9. Dry-type, medium-voltage, single-phase, ≥96 kV BIL	0.0002	0.0003	0.0003	0.0003	0.0001
10. Dry-type, medium-voltage, three-phase, ≥96 kV BIL	0.02	0.03	0.03	0.04	0.01
Total	10.09	11.27	12.39	12.26	11.41

TABLE II.36.—CUMULATIVE PRIMARY ENERGY SAVINGS BETWEEN 2007–2035: DRY-TYPE PRODUCT CLASSES

Product class	Cumulative primary energy savings (quads)				
	CSL 1	CSL 2	CSL 3	CSL 4	CSL 5
3. Dry-type, low-voltage, single-phase	0.35	0.39	0.39	0.43	0.44
4. Dry-type, low-voltage, three-phase	4.39	5.07	5.87	6.53	7.20
5. Dry-type, medium-voltage, single-phase, 20–45 kV BIL	0.0012	0.0014	0.0017	0.0020	0.0021
6. Dry-type, medium-voltage, three-phase, 20–45 kV BIL	0.05	0.06	0.08	0.09	0.09
7. Dry-type, medium-voltage, single-phase, 46–95 kV BIL	0.0010	0.0012	0.0017	0.0019	0.00221
8. Dry-type, medium-voltage, three-phase, 46–95 kV BIL	0.17	0.21	0.33	0.38	0.41
9. Dry-type, medium-voltage, single-phase, ≥96 kV BIL	0.0001	0.0002	0.0003	0.0003	0.0004
10. Dry-type, medium-voltage, three-phase, ≥96 kV BIL	0.02	0.02	0.03	0.04	0.04
Total	4.98	5.75	6.71	7.46	8.18

I. Life-Cycle Cost Sub-Group Analysis

The LCC sub-group analysis evaluates impacts on identifiable groups of customers, such as customers of different business types, who may be disproportionately affected by any national energy efficiency standard level. The Department intends to analyze the LCC and PBPs for those customers that fall into those identifiable groups.

Also, the Department plans to examine variations in energy prices and variations in energy use that might affect the NPV of a standard to customer sub-populations. To the extent possible, the Department will get estimates of the variability of each input parameter and consider this variability in its calculation of customer impacts. Variations in energy use for a particular equipment type depend on factors such as climate and type of business.

The Department will determine the effect on customer sub-groups using the LCC spreadsheet model. The spreadsheet model used for the LCC analysis can be used with different data inputs. The standard LCC analysis includes various customer types that use distribution transformers. The Department can analyze the LCC for any sub-group, such as rural electric cooperatives, by using the LCC spreadsheet model and sampling only that sub-group. Details of this model are explained in section II.F, describing the LCC and PBP analyses. The Department will be especially sensitive to purchase price increases (''first cost'' increases) to avoid negative impacts on identifiable population groups such as small businesses (*i.e.*, those with low annual revenues), which may not be able to afford a significant increase in the price of distribution transformers.

J. Manufacturer Impact Analysis

The Process Rule, 10 CFR Part 430, Subpart C, Appendix A, provides guidance for conducting a manufacturer impact analysis, and the Department intends to apply this methodology to its evaluation of standards for distribution transformers. The Process Rule gives guidelines for the consideration of financial impacts, as well as a wide range of quantitative and qualitative industry impacts that might occur following the adoption of a standard. For example, a particular standard level, if adopted by DOE, could require changes to distribution transformer manufacturing practices. The Department intends to identify and understand these impacts through interviews with manufacturers and other stakeholders during the NOPR stage of its analysis.

1. Sources of Information for the Manufacturer Impact Analysis

Many of the analyses described above, including manufacturing costs and shipment forecasts, provide important information applicable to the manufacturer impact analysis. The Department's contractor will review and supplement this information through interviews with manufacturers. This interview process plays a key role in the manufacturer impact analysis because it allows interested parties to privately express their views on important issues. To preserve confidentiality, the Department's contractor aggregates these perspectives across manufacturers, creating a combined opinion or estimate for the Department. This process enables the Department to incorporate sensitive information from manufacturers in the rulemaking process, without specifying precisely which manufacturer provided a certain set of data.

The Department conducts interviews with manufacturers to gain insight into the range of potential impacts of standards. Information is solicited specifically on the potential impacts of efficiency levels on sales, direct employment, capital assets, and industrial competitiveness. The Department prefers an interactive interview process because it helps clarify responses and identify additional issues. Before the interviews, the Department will circulate a draft document showing the estimates of the financial parameters based on publicly available information. The Department will solicit comments and suggestions on these estimates during the interviews.

The Department's contractor will ask interview participants to notify it, either in writing or orally, of any confidential materials. The Department will consider all relevant information in its decision-making process. However, DOE will not make confidential information available in the public record. The Department also will ask participants to identify all information that they wish to have included in the public record and whether they want it to be presented with or without attribution.

The Department's contractors will collate the completed interview questionnaires and prepare a summary of the major issues.

2. Industry Cash Flow Analysis

The industry cash flow analysis relies primarily on the Government Regulatory Impact Model (GRIM). The Department uses GRIM to analyze the financial impacts of more stringent energy efficiency standards on the industry.

The GRIM analysis uses a number of factors to determine annual cash flows from a new standard: Annual expected revenues; manufacturer costs (including cost of goods, capital depreciation, research and development, selling, and general administrative costs); taxes; and conversion expenditures. The Department compares the results against base case projections that involve no new standards. The financial impact of new standards is the difference between the two sets of discounted annual cash flows. Other performance metrics, such as return on invested capital, also are available from GRIM.

3. Manufacturer Sub-Group Analysis

Industry cost estimates are not adequate to assess differential impacts among sub-groups of manufacturers. Small and niche manufacturers, or manufacturers exhibiting a cost structure that differs largely from the industry average could experience a greater negative impact. The Department typically uses the results of the industry characterization to group manufacturers exhibiting similar characteristics.

During the manufacturer interview process, the Department's contractor will discuss the potential sub-groups and sub-group members that DOE has identified for the analysis. The contractor will encourage the manufacturers to recommend sub-groups or characteristics that are appropriate for the manufacturer sub-group analysis.

4. Competitive Impacts Assessment

The Department also takes into consideration whether a new standard is likely to reduce industry competition and the Attorney General determines the impacts, if any, of any reduced competition. The Department's contractors will make a determined effort to gather firm-specific financial information and impacts. The competitive analysis will focus on assessing the impacts to smaller, yet significant, manufacturers. The Department will base the assessment on manufacturing cost data and on information collected from interviews with manufacturers, which will focus on gathering information to help assess asymmetrical cost increases to some manufacturers, increased proportions of fixed costs that could potentially increase business risks, and potential barriers to market entry (*e.g.*, proprietary technologies).

5. Cumulative Regulatory Burden

The Department will recognize and seek to mitigate the overlapping effects on manufacturers of new or revised DOE standards and other regulatory actions affecting the same products. DOE will analyze and consider the impact on manufacturers of multiple product-specific regulatory actions. These factors will be considered in setting rulemaking priorities, assessing manufacturers impacts of a particular standard, and establishing the effective date for a new or revised standard. In particular, DOE will seek to propose effective dates for new or revised standards that are appropriately coordinated with other regulatory actions to mitigate any cumulative burden.

K. Utility Impact Analysis

The Department intends to determine whether a proposed standard will achieve the maximum improvement in energy efficiency or the maximum reduction in energy use that is technologically feasible and economically justified. To determine whether economic justification exists, the Department will review comments on the proposal and determine that the benefits of the proposed standard exceed its burdens to the greatest extent practicable, weighing several factors. (42 U.S.C. 6295 (o)(2)(B)) To estimate the effects of proposed distribution transformer standard levels on the electric utility industry, the Department intends to use a variant of EIA's NEMS.[4] EIA used NEMS to produce its Annual Energy Outlook (*AEO*). The Department will use a variant known as NEMS–BT to provide key inputs to the analysis, as well as some exogenous calculations. The utility impact analysis is a comparison between model results for the base case and policy cases in which proposed standards are in place. The analysis will consist of forecasted differences between the base case and standards cases for electricity generation, installed capacity, sales, and prices.

The use of NEMS for the utility impact analysis offers several advantages. As the official DOE energy forecasting model, it relies upon a set of assumptions that are transparent and have received wide exposure and commentary. NEMS allows an estimate of the interactions between the various energy supply and demand sectors and the economy as a whole. The utility impact analysis will determine the changes in installed capacity and generation by fuel type produced by each candidate standard level, as well as changes in electricity sales to the commercial sector.

The Department will conduct the utility impact analysis as a variant of *AEO 2003*, with the same basic set of assumptions applied. For example, the operating characteristics (energy conversion efficiency, emissions rates, *etc.*) of future electricity generating plants are as specified in the *AEO 2003* reference case, as are the prospects for natural gas supply.

The Department will also explore deviations from some of the reference case assumptions to represent alternative futures. Two alternative scenarios use the high- and low-economic-growth cases of *AEO 2003* (the reference case corresponds to medium growth). The high-economic-growth case assumes higher projected growth rates for population, labor force, and labor productivity, resulting in lower predicted inflation and interest rates relative to the reference case. The opposite is true for the low-growth case. While the Department varies supply-side growth determinants in these cases, *AEO 2003* assumes the same reference case energy prices for all three economic growth cases. Different economic growth scenarios will affect the rate of growth of electricity demand.

The Department will generate transformer load shapes for use in NEMS using LCC and NES results. The Department will then use NEMS to predict growth in demand to build up a projection of the total electric system load growth for each region. The Department will use the projection to predict the necessary additions to capacity. The Department will implement the accounting of efficiency standards in NEMS–BT by decrementing the appropriate reference case load shape. The Department will determine the size of the decrement using data for the per-unit energy savings developed in the LCC and PBP analyses and the shipments forecast developed for the NES analysis.

Since the *AEO 2003* version of NEMS forecasts only to the year 2025, the Department must extrapolate results to 2035. The Department will use EIA's approach for forecasting fuel prices for the Federal Energy Management Program (FEMP) for Federal sector energy prices. FEMP uses these prices to estimate life-cycle costs of Federal equipment procurements. For petroleum products, the Department will determine regional price forecasts to 2035 from the average growth rate for world oil prices over the years 2010 to 2025 used in combination with refinery and distribution markups from the year 2025. Similarly, the Department will derive natural gas prices to 2035 from an average growth rate figure in combination with regional prices from the year 2025.

L. Employment Impact Analysis

DOE's Process Rule, 10 CFR Part 430, Subpart C, Appendix A, provides guidance for consideration of the impact of candidate standard levels on employment, both direct and indirect. The Process Rule states a general presumption against any proposed standard level that would cause significant plant closures or losses of domestic employment, unless specifically identified expected benefits of the standard would outweigh the adverse effects.

The Department estimates the impacts of standards on employment for equipment manufacturers, relevant service industries, energy suppliers, and the economy in general. Both indirect and direct employment impacts are covered. Direct employment impacts would result if standards led to a change in the number of employees at manufacturing plants and related supply and service firms. Direct impact estimates are covered in the manufacturer impact analysis.

Indirect impacts are impacts on the national economy other than in the manufacturing sector being regulated. Indirect impacts may result both from expenditures shifting among goods (substitution effect) and changes in income which lead to a change in overall expenditure levels (income effect). The Department defines indirect employment impacts from standards as net jobs eliminated or created in the general economy as a result of increased spending driven by the increased price of equipment and reduced expenditures on energy.

The Department expects new distribution transformer standards to increase the total installed cost of equipment (customer purchase price plus sales tax, and installation). It expects the new standards to decrease energy consumption, and thus expenditures on energy. Over time, the increased total installed cost is paid back through energy savings. The

[4] For more information on NEMS, please refer to the U.S. Department of Energy, Energy Information Administration documentation. A useful summary is *National Energy Modeling System: An Overview 2000*, DOE/EIA–0581(2000), March, 2000. The Department/EIA approves use of the name NEMS to describe only an official version of the model without any modification to code or data. Because this analysis entails some minor code modifications and the model is run under various policy scenarios that are variations of DOE/EIA assumptions, in this analysis the Department refers to it by the name NEMS–BT (BT is DOE's Building Technologies Program, under whose aegis this work is performed).

savings in energy expenditures may be spent on new commercial investment and other items. Using an input/output model of the U.S. economy, this analysis seeks to estimate the effects on different sectors and the net impact on jobs. The Department will estimate national impacts for major sectors of the U.S. economy in the NOPR. Public and commercially available data sources and software will be used to estimate employment impacts. The Department will make all methods and documentation available for review.

For recent energy efficiency standards rulemakings, the Department has used the Impact of Building Energy Efficiency Programs (IMBUILD) spreadsheet model to analyze indirect employment impacts. The Department's Building Technologies Program office developed IMBUILD, which is a special purpose version of the Impact Analysis for Planning (IMPLAN) national input-output model. IMPLAN specifically estimates the employment and income effects of building energy technologies. The IMBUILD model is an economic analysis system that focuses on those sectors most relevant to buildings and characterizes the interconnections among 35 sectors as national input-output matrices using data from the Bureau of Labor Statistics. The IMBUILD output includes employment, industry output, and wage income. Changes in expenditures due to commercial and industrial equipment standards can be introduced to IMBUILD as perturbations to existing economic flows and the resulting net national impact on jobs by sector can be estimated.

Although the Department intends to use IMBUILD for its analysis of employment impacts, it welcomes any input on tools and factors to be considered.

M. Environmental Assessment

As with the utility impact analysis, the Department will assess the impacts of proposed distribution transformer standard levels on certain environmental indicators using NEMS–BT to provide key inputs to the analysis, as well as some exogenous calculations. The environmental assessment produces results in a manner similar to those provided in *AEO 2003*.

The intent of the environmental assessment is to provide emissions results estimates, and to fulfill requirements to properly quantify and consider the environmental effects of all new Federal rules. The environmental assessment that will be produced by NEMS–BT considers only two pollutants, sulfur dioxide (SO_2) and nitrogen oxides (NO_X), and one other emission, carbon. The only form of carbon the NEMS–BT model tracks is carbon dioxide (CO_2), so the carbon discussed in this analysis is only in the form of CO_2. For each of the trial standard levels, DOE will calculate total undiscounted and discounted emissions using NEMS–BT and will use external analysis as needed.

The Department will conduct the environmental assessment as an incremental policy impact (*i.e.*, a transformer standard) of the *AEO 2003* forecast, with the same basic set of assumptions applied. For example, the emissions characteristics of an electricity generating plant will be exactly those used in *AEO 2003.* Also, forecasts conducted with NEMS–BT take into consideration the supply-side and demand-side effects on the electric utility industry. Thus, the Department's analysis will take into account any factors impacting the type of electricity generation and, in turn, the type and amount of utility-industry-generated air-borne emissions.

The NEMS–BT model tracks carbon emissions with a specialized carbon emissions estimation subroutine, producing reasonably accurate results due to the broad coverage of all sectors and inclusion of interactive effects. Past experience with carbon results from NEMS suggests that emissions estimates are somewhat lower than emissions based on simple average factors. One of the reasons for this divergence is that NEMS tends to predict that conservation displaces generating capacity in future years. On the whole, NEMS–BT provides carbon emissions results of reasonable accuracy, at a level consistent with other Federal published results.

NEMS–BT also reports SO_2 and NO_X which the Department has reported in past analyses. The Clean Air Act Amendments of 1990 set an SO_2 emissions cap on all power generation. The attainment of this target, however, is flexible among generators through the use of emissions allowances and tradeable permits. NEMS includes a module for SO_2 allowance trading and delivers a forecast of SO_2 allowance prices. Accurate simulation of SO_2 trading implies that physical emissions effects will be zero, as long as emissions are at the ceiling. This fact has caused considerable confusion in the past. However, there is an SO_2 benefit from conservation in the form of a lower allowance price as a result of additional allowances from this rule, and, if large enough to be calculable by NEMS–BT, the Department will report it. NEMS also has an algorithm for estimating NO_X emissions from power generation. Two recent regulatory actions proposed by the EPA regarding regulations and guidelines for best available retrofit technology determinations and the reduction of interstate transport of fine particulate matter and ozone are tending towards further NO_X reductions and likely to an eventual emissions cap on nation-wide NO_X. 69 FR 25184 (May 5, 2004) and 69 FR 32684 (June 10, 2004). As with SO_2 emissions, a cap on NO_X emissions will likely result in no physical emissions effects from equipment efficiency standards.

The reporting of the results for the environmental assessment are similar to a complete NEMS run as published in the *AEO 2003*. These results include power sector emissions for SO_2, NO_X, and carbon, and SO_2 prices in five-year forecasted increments extrapolated to the year 2035. The outcome of the analysis for each candidate standard level is reported as a deviation from the *AEO 2003* reference (base) case.

N. Regulatory Impact Analysis

The Department will prepare a draft regulatory impact analysis in compliance with 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 (OIRA). 58 FR 51735.

As part of the regulatory impact analysis, the Department will identify and seek to mitigate the overlapping effects on manufacturers of new or revised DOE standards and other regulatory actions affecting the same equipment. Through manufacturer interviews and literature searches, the Department will compile information on burdens from existing and impending regulations affecting distribution transformers. The Department also seeks input from stakeholders regarding regulations that it should consider.

The NOPR will include a complete quantitative analysis of alternatives to the proposed conservation standards. The Department plans to use the NES spreadsheet model (as discussed in section II.H on the national impact analysis) to calculate the NES and NPV corresponding to specified alternatives to the proposed conservation standards.

III. Proposed Standards Scenarios

The Process Rule, 10 CFR Part 430, Subpart C, Appendix A, gives guidance to the Department to specify candidate standards levels in the ANOPR, but not to propose a particular standard. The Department intends to review the public input received during the comment period following the ANOPR public meeting and update the analyses appropriately for each product class before issuing the NOPR.

The Department seeks comments on whether standards that meet alternative scenarios would provide energy savings to the Nation comparable to the savings that would be obtained by the highest standards that are technologically feasible and economically justified, effective in 2007, or the final date to be determined in the NOPR analysis. The Department may consider standards that meet the following alternative scenarios, for example:

- A moderate increase in the efficiency level at an earlier effective date, for example, an effective date two years after the publication of the Final Rule.
- A larger increase in efficiency level at a later effective date.
- A two-phase approach combining the two scenarios, for example, a moderate increase in efficiency level for some product classes effective at an earlier date and an even higher efficiency level effective at a later date.

IV. Public Participation

A. Attendance at Public Meeting

The time and date of the public meeting are listed in the **DATES** section at the beginning of this notice of proposed rulemaking. Anyone who wants to attend the public meeting must notify Ms. Brenda Edwards-Jones at (202) 586–2945. Foreign nationals visiting DOE Headquarters are subject to advance security screening procedures, requiring a 30-day advance notice. A foreign national who wishes to participate in the meeting must tell DOE of this fact as soon as possible by contacting Ms. Brenda Edwards-Jones to initiate the necessary procedures.

B. Procedure for Submitting Requests To Speak

Any person who has an interest in today's notice, or who is a representative of a group or class of persons that has an interest in these issues, may request an opportunity to make an oral presentation. Please hand-deliver requests to speak, along with a computer diskette or CD in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format to the address shown at the beginning of this advance notice of proposed rulemaking between the hours of 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Requests may also be sent by mail or e-mail to: *Brenda.Edwards-Jones@ee.doe.gov.*

Persons requesting to speak should briefly describe the nature of their interest in this rulemaking and provide a telephone number for contact. The Department requests persons selected to be heard to submit an advance copy of their statements at least two weeks before the public meeting. At its discretion, DOE may permit any person who cannot supply an advance copy of his or her statement to participate, if that person has made advance alternative arrangements with the Building Technologies Program. The request to give an oral presentation should ask for such alternative arrangements.

C. Conduct of Public Meeting

The Department will designate a DOE official to preside at the public meeting and may also use a professional facilitator to aid discussion. The meeting will not be a judicial or evidentiary-type public hearing, but DOE will conduct it in accordance with 5 U.S.C. 553 and section 336 of EPCA. (42 U.S.C. 6306) A court reporter will be present to record the transcript of the proceedings. The Department reserves the right to schedule the order of presentations and to establish the procedures governing the conduct of the public meeting. After the public meeting, interested parties may submit further comments on the proceedings as well as on any aspect of the rulemaking until the end of the comment period.

The public meeting will be conducted in an informal, conference style. The Department will present summaries of comments received before the public meeting, allow time for presentations by participants, and encourage all interested parties to share their views on issues affecting this rulemaking. Each participant will be allowed to make a prepared general statement (within time limits determined by DOE) before the discussion of specific topics. The Department will permit other participants to comment briefly on any general statements.

At the end of all prepared statements on a topic, DOE will permit participants to clarify their statements briefly and comment on statements made by others. Participants should be prepared to answer questions by DOE and by other participants concerning these issues. Department representatives may also ask questions of participants concerning other matters relevant to the public meeting. The official conducting the public meeting will accept additional comments or questions from those attending, as time permits. The presiding official will announce any further procedural rules or modification of the above procedures that may be needed for the proper conduct of the public meeting.

The Department will make the entire record of this proposed rulemaking, including the transcript from the public meeting, available for inspection at the U.S. Department of Energy, Forrestal Building, Room 1J–018 (Resource Room of the Building Technologies Program), 1000 Independence Avenue, SW., Washington, DC, (202) 586–9127, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays. Any person may buy a copy of the transcript from the transcribing reporter.

D. Submission of Comments

The Department will accept comments, data, and information regarding all aspects of this ANOPR before or after the public meeting, but no later than the date provided at the beginning of this advance notice of proposed rulemaking. Please submit comments, data, and information electronically. Send them to the following E-mail address: *TransformerANOPRComment@ee.doe.gov*. Submit electronic comments in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format and avoid the use of special characters or any form of encryption. Comments in electronic format should be identified by the docket number EE–RM/STD–00–550, and wherever possible carry the electronic signature of the author. Absent an electronic signature, comments submitted electronically must be followed and authenticated by submitting the signed original paper document. No telefacsimiles (faxes) will be accepted.

Pursuant to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit two copies: one copy of the document including all the information believed to be confidential, and one copy of the document with the information believed to be confidential deleted. The Department of Energy will make its own determination about the confidential status of the information and treat it according to its determination.

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

E. Issues on Which DOE Seeks Comment

The Department is interested in receiving comments on all aspects of this ANOPR. DOE especially invites comments or data to improve the Departments' analysis, including data or information that will respond to the following questions or concerns that were addressed in this ANOPR:

1. Definition and Coverage

The Department seeks to clarify coverage under this proposed activity. This ANOPR proposes a definition that more closely parallels NEMA's TP 1, outlining a broad scope of coverage and then identifying exemptions. The Department invites stakeholders to comment on the new distribution transformer definition, including the revised scope, the exemptions list, and the exemptions list definitions (see section II.A for details).

2. Product Classes

The Department proposes product classes that are in keeping with those in NEMA's TP 1–2002 document, specifically by breaking down the population of distribution transformers by type of insulation (liquid-immersed or dry-type), number of phases (single or three), voltage (low or medium), and BIL rating (for medium-voltage dry-types). The Department is proposing a greater degree of specificity by BIL rating than that provided in NEMA's TP 1–2002 document. The Department requests feedback from stakeholders on its BIL classification system for medium-voltage, dry-type transformers (see section II.A for details).

3. Engineering Analysis Inputs

In Chapter 5 of the TSD, the Department presents all the costs of material used as design inputs to the modeling software. The Department asks that stakeholders, particularly manufacturers, review the material prices and comment on whether they represent reasonable input costs for the engineering analysis.

4. Design Option Combinations

For each representative unit analyzed, the Department selected several methods of construction, by varying core steels and winding material. These combinations represent the most common types of transformers made, as well as the lowest first-cost and the maximum technologically feasible design. The complete breakdown of the design option combinations is presented in Chapter 5 of the TSD. The Department requests that stakeholders review these design option combinations and comment on whether they are the best ones to use for a given representative unit. Also, the Department requests comments on the screening analysis, regarding both technologies and materials that were included and those screened out from further consideration. (See section II.B for details.)

5. The 0.75 Scaling Rule

The Department applied a 0.75 power law scaling rule to two key components of the transformer efficiency analysis:

(a) In simplifying the engineering analysis by taking 115 different kVA ratings and turning them into 13 engineering design lines with 13 representative units, the Department committed to using the 0.75 scaling rule to scale losses from the representative unit to other kVA ratings within a design line. The Department requests comments on this practice, discussed in section II.C.2 and outlined in Chapter 5 of the TSD.

(b) To simplify the economic analysis, the Department extrapolated economic costs and benefits for a particular design line to each of the kVA ratings using the 0.75 rule. Not all economic costs and benefits of transformer efficiency scale according to the 0.75 rule, although the rule may be a reasonable approximation for ranges of kVA ratings. The Department requests comment on the desirability of having a simple scaling for transformer efficiency economics versus using more detailed scaling methods that may result in a more complicated relationship between kVA rating and efficiency level.

6. Modeling of Transformer Load Profiles

Lacking sufficient empirical transformer loading data, the Department developed models of transformer loads specific to each type of transformer. The Department requests comments on the methods it employed as well as sources of specific loading data that it could use in the NOPR analyses. (See section II.F for details.)

7. Distribution Chain Markups

The Department used cost data from RS Means combined with manufacturer price estimates and U.S. economic census data to estimate markups and installation costs for transformers from the factory door through completed installation. The Department requests stakeholder feedback on markup factors, methods, and data used by the Department. (See section II.E for details.)

8. Discount Rate Selection and Use

The Department used a weighted average cost of capital as the discount rate for the LCC and the OMB-mandated discounted rates for the NPV calculation. The Department requests stakeholder feedback on the appropriateness of these discount rates. (See sections II.F and II.H for details.)

9. Baseline Determination Through Purchase Evaluation Formulae

The Department characterized current market conditions for both liquid-immersed and dry-type transformers using a distribution of load and no-load loss values, and assumed percentages of customers that evaluate their transformer purchases by considering the value of load and no-load losses. The Department invites further comment on the purchase decision model and transformer evaluation behavior for both liquid-immersed and dry-type transformers, especially:

- Actual A and B values used in the current market,
- Actual efficiency of the low first-cost designs currently on the market since the efficiency of the low first-cost designs has a large impact on overall energy savings estimates,
- Applicability of the approach to characterize both medium- and low-voltage, dry-type transformer market behavior, and
- The stability over time of the transformer market, especially the percent of evaluators and levels of A and B values.

(See section II.F for details.)

10. Electricity Prices

The Department requests stakeholder feedback on the two methods it used for this rulemaking to determine the cost of electricity consumed by transformers. For dry-type transformers used predominately by commercial and industrial firms, the Department calculated estimated bills based on a sample of electricity tariffs. For liquid-immersed transformers, the Department used market and FERC Form 714 data to estimate the marginal cost of electricity to utilities. (See section II.F for details.)

11. Load Growth Over Time

Since the Department lacks specific information on transformer load growth over time, it assumed for its default ANOPR scenario a 1-percent annual growth rate for liquid-immersed transformers and zero-percent load growth for dry-type transformers. The Department requests stakeholders comments on these assumptions. (See section II.F for details.)

12. Life-Cycle Cost Sub-Groups

The Department has identified various categories of utilities, such as municipal utilities and rural electric cooperatives, as possible sub-groups for which to conduct a separate LCC analysis. The Department seeks stakeholder feedback regarding the most appropriate sub-groups to include in the NOPR analysis. (See section II.I for details.)

13. Utility Deregulation Impacts

The Department is aware of ongoing wholesale and retail deregulation activities in the electric utility industry, but is uncertain how this deregulation will affect transformer purchase decisions in the long term. The Department requests comments from stakeholders with specific information regarding the impact of deregulation. Utility deregulation will likely have the most significant impacts on LCC results, through changes in electricity prices. LCC Details are found in TSD Chapter 8.

V. Regulatory Review and Procedural Requirements

This advance notice of proposed rulemaking was submitted for review to OIRA in the Office of Management and Budget under Executive Order 12866, ''Regulatory Planning and Review.'' 58 FR 51735. If DOE later proposes energy conservation standards for certain distribution transformers, the rulemaking would likely constitute a significant regulatory action, and DOE would prepare and submit to OIRA for review the assessment of costs and benefits required by section 6(a)(3) of the Executive Order. In addition, various other analyses and procedures may apply to such future rulemaking action, including those required by the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.*; the Unfunded Mandates Act of 1995, Pub. L. 104–4; the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*; the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*; and certain Executive Orders.

VI. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's Advance Notice of Proposed Rulemaking.

Issued in Washington, DC, on July 13, 2004.

David K. Garman,

Assistant Secretary, Energy Efficiency and Renewable Energy.

[FR Doc. 04–16573 Filed 7–28–04; 8:45 am]

BILLING CODE 6450–01–P