DEPARTMENT OF ENERGY

10 CFR Part 431

[Docket No. EERE–2010–BT–STD–0048]

RIN 1904–AC04

Energy Conservation Program: Energy Conservation Standards for Distribution Transformers

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

ACTION: Final rule.

SUMMARY: The Energy Policy and Conservation Act of 1975 (EPCA), as amended, prescribes energy conservation standards for various consumer products and certain commercial and industrial equipment, including distribution transformers. EPCA also requires the U.S. Department of Energy (DOE) to determine whether more-stringent standards would be technologically feasible and economically justified, and would save a significant amount of energy. In this final rule, DOE is adopting more-stringent energy conservation standards for distribution transformers. It has determined that the amended energy conservation standards for this equipment would result in significant conservation of energy, and are technologically feasible and economically justified.

DATES: The effective date of this rule is June 17, 2013. Compliance with the amended standards established for distribution transformers in this final rule is required as of January 1, 2016.

ADDRESSES: The docket for this rulemaking is available for review at *www.regulations.gov*, including **Federal Register** notices, framework documents, public meeting attendee lists and transcripts, comments, negotiated rulemaking, and other supporting documents/materials. All documents in the docket are listed in the *www.regulations.gov* index. However, not all documents listed in the index may be publicly available, such as information that is exempt from public disclosure.

A link to the docket Web page can be found at: *http://www.regulations.gov/#!docketDetail;rpp=10;po=0;D=EERE-2010-BT-STD-0048.* The regulations.gov Web page will contain simple instructions on how to access all documents, including public comments, in the docket.

For further information on how to review the docket, contact Ms. Brenda Edwards at (202) 586–2945 or by email: *Brenda.Edwards@ee.doe.gov*.

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SUPPLEMENTARY INFORMATION:

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I. Summary of the Final Rule and Its Benefits

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for Consumer Products Other Than Automobiles. Part C of Title III of EPCA (42 U.S.C. 6311–6317) established a similar program for ''Certain Industrial Equipment,'' including distribution transformers.[1] Pursuant to EPCA, any new or amended energy conservation standard that DOE prescribes for certain equipment, such as distribution transformers, shall be designed to achieve the maximum improvement in energy efficiency that DOE determines is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A), 6316(a)) Furthermore, any new or amended standard must result in significant conservation of energy. (42 U.S.C. 6295(o)(3)(B), 6316(a)) In accordance with these and other statutory provisions addressed in this rulemaking, DOE is adopting amended energy conservation standards for distribution transformers. The amended standards are summarized in Table I.1 through Table I.3. Table I.4 shows the mapping of trial standard levels (TSLs) to energy efficiency levels (ELs),[2] and Table I.5 through Table I.8 show the standards in terms of minimum electrical efficiency. These amended standards apply to all equipment that is listed in Table I.1 and manufactured in, or imported into, the United States on or after January 1, 2016. As discussed in section IV.C.8 of this preamble, any distribution transformer having a kilovolt-ampere (kVA) rating falling between the kVA ratings shown in the tables shall meet a minimum energy efficiency level calculated by a linear interpolation of the minimum efficiency requirements of the kVA ratings immediately above and below that rating.[3]

For the reasons discussed in this preamble, particularly in Section V, DOE is adopting TSL 1 for liquid-immersed distribution transformers. DOE acknowledges the input of various stakeholders in support of a more stringent energy conservation standard for liquid-immersed distribution transformers. DOE notes that the potential for significant disruption in the steel supply market at higher efficiency levels was a key element in adopting TSL 1 in this rulemaking. DOE will monitor the steel and liquid-immersed distribution transformer markets and by no later than 2016, determine whether interim changes to market conditions, particularly the supply chain for amorphous steel, justify re-evaluating the efficiency standards adopted in today's rulemaking.

Although DOE proposed TSL 1 for low-voltage dry-type distribution transformers, DOE is adopting in this final rule TSL 2 for such transformers for the reasons discussed in greater detail in Section IV.I.5.B. DOE acknowledges that various stakeholders

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

[2] A detailed description of the mapping of trial standard level to energy efficiency levels can be found in the Technical Support Document, chapter 10 section 10.2.2.3.

[3] kVA, an abbreviation for kilovolt-ampere, is a capacity metric used by industry to classify transformers. A transformer's kVA rating represents its output power when it is fully loaded (*i.e.,* 100 percent).

argued that concerns regarding small manufacturers should not be a barrier to adopting TSL 3 because small manufacturers have the option of either sourcing cores from third parties or investing in mitering machines. DOE will monitor the low-voltage dry-type distribution transformer market, and by no later than 2016, determine whether market conditions justify re-evaluating the efficiency standards adopted in today's rulemaking.

TABLE I.1—ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

[Compliance starting January 1, 2016]

Equipment classes	Design line	Type	Phase count	BIL*	Adopted TSL
1	1, 2 and 3	Liquid-immersed	1	All	1
2	4 and 5	Liquid-immersed	3	All	1

* BIL means ''basic impulse insulation level'' and measures how resistant a transformer's insulation is to large voltage transients.

TABLE I.2—ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

[Compliance starting January 1, 2016]

Equipment class	Design line	Type	Phase count	BIL*	Adopted TSL
3	6	Low-voltage dry-type	1	≤ 10 kV	2
4	7 and 8	Low-voltage dry-type	3	≤ 10 kV	2

* BIL means ''basic impulse insulation level'' and measures how resistant a transformer's insulation is to large voltage transients.

TABLE I.3—ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

[Compliance starting January 1, 2016]

Equipment class	Design line	Type	Phase count	BIL*	Adopted TSL
5	9 and 10	Medium-voltage dry-type	1	25–45 kV	2
6	9 and 10	Medium-voltage dry-type	3	25–45 kV	2
7	11 and 12	Medium-voltage dry-type	1	46–95 kV	2
8	11 and 12	Medium-voltage dry-type	3	46–95 kV	2
9	13A and 13B	Medium-voltage dry-type	1	≥96 kV	2
10	13A and 13B	Medium-voltage dry-type	3	≥96 kV	2

* BIL means ''basic impulse insulation level'' and measures how resistant a transformer's insulation is to large voltage transients.

TABLE I.4—TRIAL STANDARD LEVEL TO ENERGY EFFICIENCY LEVEL MAPPING FOR DISTRIBUTION TRANSFORMER ENERGY CONSERVATION STANDARDS

Type	Design line	Phase count	TSL	Energy efficiency level	Efficiency (%)
Liquid-immersed	1	1	1	1 (0.4 actual)*	99.11
	2	1		Base (0.5 actual)*	98.95
	3	1		1 (1.1 actual)*	99.49
	4	3		1	99.16
	5	3		1	99.48
Low-voltage dry-type	6	1	2	Base	98.00
	7	3		3	98.60
	8	3		2	99.02
Medium-voltage dry-type	9	3	2	1	98.93
	10	3		2	99.37
	11	3		1	98.81
	12	3		2	99.30
	13A	3		1	98.69
	13B	3		2	99.28

* Because of scaling, actual efficiency values unavoidably differ from nominal EL values.

TABLE I.5—ELECTRICAL EFFICIENCIES FOR ALL LIQUID-IMMERSED DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES

[Compliance starting January 1, 2016]

Equipment Class 1		Equipment Class 2	
kVA	%	kVA	%
Standards by kVA and Equipment Class			
10	98.70	15	98.65

TABLE I.5—ELECTRICAL EFFICIENCIES FOR ALL LIQUID-IMMERSED DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES—Continued

[Compliance starting January 1, 2016]

Equipment Class 1		Equipment Class 2	
kVA	%	kVA	%
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1,000	99.43
667	99.52	1,500	99.48
833	99.55	2,000	99.51
		2,500	99.53

TABLE I.6—ELECTRICAL EFFICIENCIES FOR ALL LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES

[Compliance starting January 1, 2016]

Equipment Class 3		Equipment Class 4	
kVA	%	kVA	%
Standards by kVA and Equipment Class			
15	97.70	15	97.89
25	98.00	30	98.23
37.5	98.20	45	98.40
50	98.30	75	98.60
75	98.50	112.5	98.74
100	98.60	150	98.83
167	98.70	225	98.94
250	98.80	300	99.02
333	98.90	500	99.14
		750	99.23
		1,000	99.28

TABLE I.7—ELECTRICAL EFFICIENCIES FOR ALL MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES

[Compliance starting January 1, 2016]

Equipment Class 5		Equipment Class 6		Equipment Class 7		Equipment Class 8		Equipment Class 9		Equipment Class 10	
kVA	%	kVA	%	kVA	%	kVA	%	kVA	%	kVA	%
Standards by kVA and Equipment Class											
15	98.10	15	97.50	15	97.86	15	97.18				
25	98.33	30	97.90	25	98.12	30	97.63				
37.5	98.49	45	98.10	37.5	98.30	45	97.86				
50	98.60	75	98.33	50	98.42	75	98.13				
75	98.73	112.5	98.52	75	98.57	112.5	98.36	75	98.53		
100	98.82	150	98.65	100	98.67	150	98.51	100	98.63		
167	98.96	225	98.82	167	98.83	225	98.69	167	98.80	225	98.57
250	99.07	300	98.93	250	98.95	300	98.81	250	98.91	300	98.69
333	99.14	500	99.09	333	99.03	500	98.99	333	98.99	500	98.89
500	99.22	750	99.21	500	99.12	750	99.12	500	99.09	750	99.02
667	99.27	1,000	99.28	667	99.18	1,000	99.20	667	99.15	1,000	99.11
833	99.31	1,500	99.37	833	99.23	1,500	99.30	833	99.20	1,500	99.21
		2,000	99.43			2,000	99.36			2,000	99.28
		2,500	99.47			2,500	99.41			2,500	99.33

A. Benefits and Costs to Customers [4]

Table I.8 summarizes DOE's evaluation of the economic impacts of today's standards on customers who purchase distribution transformers, as measured by the average life-cycle cost (LCC) savings and the median payback period (PBP). DOE measures the impacts of standards relative to a base case that reflects likely trends in the distribution transformer market in the absence of amended standards. The base case predominantly consists of products at the baseline efficiency levels evaluated for each representative unit, which correspond to the existing energy conservation standards for distribution transformers. (Throughout this document, ''distribution transformers'' are also referred to as simply ''transformers.'')

TABLE I.8—IMPACTS OF TODAY'S STANDARDS ON CUSTOMERS OF DISTRIBUTION TRANSFORMERS

Design line	Average LCC savings 2011$	Median payback period years
Liquid-Immersed		
1	72	18.2
2	66	5.9
3	2,753	8.6
4	967	7.0
5	4,289	6.3
Low-voltage dry-type **		
6	N/A *	N/A *
7	1,678	3.6
8	2,588	7.7
Medium-voltage dry-type		
9	787	2.6
10	4,455	8.6
11	996	10.6
12	6,790	8.5
13A	−27	16.1
13B	4,346	12.2

* No customers are impacted by today's standard because there is no change from the minimum efficiency standard for design line 6.

** See section IV.A.3.d for discussion of core construction technique.

B. Impact on Manufacturers

The industry net present value (INPV) is the sum of the discounted cash flows to the industry from the base year through the end of the analysis period (2012 to 2045). Using a real discount rate of 7.4 percent for liquid-immersed distribution transformers, 9 percent for medium-voltage dry-type distribution transformers, and 11.1 percent for low-voltage dry-type distribution transformers, DOE estimates that the INPV for manufacturers of liquid-immersed, medium-voltage dry-type, and low-voltage dry-type distribution transformers is $575.1 million, $68.7 million, and $237.6 million, respectively, in 2011$. Under the standards of today's rule, DOE expects that manufacturers of liquid-immersed units may lose as much as 8.4 percent of their INPV, which is approximately $48.2 million; medium-voltage manufacturers may lose as much as 4.2 percent of their INPV, which is approximately $2.9 million; and low-voltage manufacturers may lose as much as 4.7 percent of their INPV, which is approximately $11.1 million. Additionally, based on DOE's interviews with the manufacturers of distribution transformers, DOE does not expect any plant closings or significant loss of employment.

C. National Benefits

DOE's analyses indicate that today's standards would save a significant amount of energy. The lifetime savings for equipment purchased in the 30-year period that begins in the year of compliance with amended standards (2016–2045) amounts to 3.63 quads.

The cumulative net present value (NPV) of total customer costs and savings of today's standards for distribution transformers, in 2011$, ranges from $3.4 billion (at a 7-percent discount rate) to $12.9 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased equipment costs for equipment purchased in 2016–2045, discounted to 2012.

In addition, today's standards would have significant environmental benefits. The energy savings would result in cumulative emission reductions of 264.7 million metric tons (Mt) [5] of carbon dioxide (CO_2), 223.3.thousand tons of nitrogen oxides (NO_X), 182.9 thousand tons of sulfur dioxide (SO_2), and 0.6 ton of mercury (Hg).[6]

The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 (otherwise known as the Social Cost of Carbon, or SCC) developed by a recent interagency process. The derivation of the SCC values is discussed in section IV.M. DOE estimates the net present monetary value of the CO_2 emissions reduction is between $0.80 billion and $13.31 billion, expressed in 2011$ and discounted to 2012. DOE also estimates the net present monetary value of the NO_X emissions reduction, expressed in 2011$ and discounted to 2012, is $93.2 million at a 7-percent discount rate and $234.1 million at a 3-percent discount rate.[7]

Table I.9 summarizes the national economic costs and benefits expected to result from today's standards for distribution transformers.

TABLE I.9—SUMMARY OF NATIONAL ECONOMIC BENEFITS AND COSTS OF DISTRIBUTION TRANSFORMER ENERGY CONSERVATION STANDARDS

Category	Present value billion 2011$	Discount rate %
Benefits		
Operating Cost Savings	6.30	7

[4] For purposes of this document, the ''consumers'' of distribution transformers are referred to as ''customers.'' Customers refer to electric utilities in the case of liquid-immersed transformers, and to utilities and building owners in the case of dry-type transformers.

[5] A metric ton is equivalent to 1.1 short tons. Results for NO_X and Hg are presented in short tons.

[6] DOE calculated emissions reductions relative to the Annual Energy Outlook (AEO) 2011 Reference case, which incorporated projected effects of all emissions regulations promulgated as of January 31, 2011, including the Clean Air Interstate Rule (CAIR, 70 FR 25162 (May 12, 2005)). Subsequent regulations, including the CAIR replacement rule, the Cross-State Air Pollution Rule (76 FR 48208 (August 8, 2011)), do not appear in the projection.

[7] DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it monetizes Hg in its rulemakings.

TABLE I.9—SUMMARY OF NATIONAL ECONOMIC BENEFITS AND COSTS OF DISTRIBUTION TRANSFORMER ENERGY CONSERVATION STANDARDS—Continued

Category	Present value billion 2011$	Discount rate %
	18.2	3
CO_2 reduction monetized value ($4.9/t case) *	0.80	5
CO_2 reduction monetized value ($22.3/t case) *	4.38	3
CO_2 reduction monetized value ($36.5/t case) *	7.51	2.5
CO_2 reduction monetized value ($67.6/t case) *	13.31	3
NO_X reduction monetized value ($2,591/ton) **	0.09	7
	0.23	3
Total benefits †	10.77	7
	22.8	3
Costs		
Incremental installed costs	2.89	7
	5.22	3
Net Benefits		
Including CO_2 and NO_X reduction monetized value	7.88	7
	17.6	3

* The CO_2 values represent global monetized values of the SCC in 2011$ in 2011 under several scenarios. The values of $4.9, $22.3, and $36.5/per metric ton (t) are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6/t represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series used by DOE incorporate an escalation factor.

** The value represents the average of the low and high NO_X values used in DOE's analysis.

† Total benefits for both the 3% and 7% cases are derived using the series corresponding to SCC value of $22.3/t.

The benefits and costs of today's standards, for equipment sold in 2016–2045, can also be expressed in terms of annualized values. The annualized monetary values are the sum of: (1) The annualized national economic value of the benefits from customer operation of equipment that meets today's standards (consisting primarily of operating cost savings from using less energy, minus increases in equipment purchase and installation costs, which is another way of representing customer NPV), and (2) the annualized monetary value of the benefits of emission reductions, including CO_2 emission reductions.[8]

Although combining the values of operating cost savings and CO_2 emission reductions provides a useful perspective, two issues should be considered. First, the national operating cost savings are domestic U.S. customer monetary savings that occur as a result of market transactions, whereas the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and CO_2 savings are performed using different methods that employ different time frames for analysis. The national operating cost savings is measured for the lifetime of distribution transformers shipped in 2016–2045. The SCC values, on the other hand, reflect the present value of some future climate-related impacts resulting from the emission of one ton of carbon dioxide in each year. Those impacts continue well beyond 2100.

Estimates of annualized benefits and costs of today's standards are shown in Table I.10. The results under the primary estimate are as follows. (All monetary values below are expressed in 2011$.) Using a 7-percent discount rate for benefits and costs (other than CO_2 reduction, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/ton in 2011), the cost of the standards in today's rule is $266 million per year in increased equipment costs, while the benefits are $581 million per year in reduced equipment operating costs, $237 million in CO_2 reductions, and $8.60 million in reduced NO_X emissions. In this case, the net benefit amounts to $561 million per year. Using a 3-percent discount rate for all benefits and costs (and the SCC series corresponding to a value of $22.3/ton in 2011), the cost of the standards in today's rule is $282 million per year in increased equipment costs, while the benefits are $983 million per year in reduced operating costs, $237 million in CO_2 reductions, and $12.67 million in reduced NO_X emissions. In this case, the net benefit amounts to $950 million per year.

[8] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2012, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of three and seven percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table I.10. From the present value, DOE then calculated the fixed annual payment over a 30-year period (2016 through 2045) that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined is a steady stream of payments.

TABLE I.10—ANNUALIZED BENEFITS AND COSTS OF AMENDED STANDARDS FOR DISTRIBUTION TRANSFORMERS SOLD IN 2016–2045

	Discount rate %	Million 2011$/year		
		Primary estimate *	Low net benefits estimate *	High net benefits estimate *
Benefits				
Operating cost savings	7	581	559	590.
	3	983	930	1003.
CO_2 reduction monetized value ($4.9/t case) **	5	57.7	57.7	57.7.
CO_2 reduction monetized value ($22.3/t case) **	3	237	237	237.
CO_2 reduction monetized value ($36.5/t case) **	2.5	377	377	377.
CO_2 reduction monetized value ($67.6/t case) **	3	721	721	721.
NO_X reduction monetized value ($2,591/ton) **	7	8.60	8.60	8.60.
	3	12.67	12.67	12.67.
Total benefits†	7% plus CO_2 range	648 to 1311	625 to 1288	656 to 1319.
	7	827	805	836.
	3% plus CO_2 range	1053 to 1716	1000 to 1663	1074 to 1737.
	3	1233	1179	1253.
Costs				
Incremental equipment costs	7	266	300	257.
	3	282	325	271.
Net Benefits				
Total†	7% plus CO_2 range	381 to 1044	325 to 988	400 to 1063.
	7	561	504	579.
	3% plus CO_2 range	771 to 1434	675 to 1338	803 to 1466.
	3%	950	854	982.

* This table presents the annualized costs and benefits associated with transformers shipped in 2016–2045. These results include benefits to customers that accrue after 2045 from equipment purchased in 2016–2045. Costs incurred by manufacturers, some of which may be incurred in preparation for the rule, are not directly included, but are indirectly included as part of incremental equipment costs. The Primary, Low Benefits, and High Benefits estimates utilize projections of energy prices from the *AEO2012* Reference case, Low Estimate, and High Estimate, respectively. In addition, incremental equipment costs reflect a constant equipment price trend in the Primary Estimate, an increasing price trend in the Low Benefits Estimate, and a declining price trend in the High Benefits Estimate. The methods used to derive projected price trends are explained in section IV.F.2.

** The CO_2 values represent global monetized values of the SCC, in 2011$, in 2011 under several scenarios. The values of $4.9, $22.3, and $36.5 per metric ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6/t represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series used by DOE incorporate an escalation factor. The value for NO_X (in 2011$) is the average of the low and high values used in DOE's analysis.

† Total Benefits for both the 3% and 7% cases are derived using the series corresponding to SCC value of $22.3/t. In the rows labeled "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

D. Conclusion

Based on the analyses culminating in this final rule, DOE found the benefits to the nation of the standards (energy savings, consumer LCC savings, positive NPV of customer benefit, and emission reductions) outweigh the burdens (loss of INPV and LCC increases for some users of this equipment). DOE has concluded that the standards in today's final rule represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in significant conservation of energy.

II. Introduction

The following section briefly discusses the statutory authority underlying today's final rule, as well as some of the relevant historical background related to the establishment of today's amended standards.

A. Authority

Title III, Part B of the Energy Policy and Conservation Act of 1975 (EPCA or the Act), Public Law 94–163 (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for "Consumer Products Other Than Automobiles." Part C of Title III of EPCA (42 U.S.C. 6311–6317) established a similar program for "Certain Industrial Equipment," including distribution transformers.[9] The Energy Policy Act of 1992 (EPACT 1992), Public Law 102–486, amended EPCA and directed the Department of Energy to prescribe energy conservation standards for those distribution transformers for which DOE determines such standards would be technologically feasible, economically justified, and would result in significant energy savings. (42 U.S.C. 6317(a)) The Energy Policy Act of 2005 (EPACT 2005), Public Law 109–58, amended EPCA to establish energy conservation standards for low-voltage dry-type distribution transformers.[10] (42 U.S.C. 6295(y))

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

[10] EPACT 2005 established that the efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2007 shall be the Class I Efficiency Levels for distribution transformers specified in Table 4–2 of the "Guide for Determining Energy Efficiency for Distribution

For those distribution transformers for which DOE determines that energy conservation standards are warranted, the DOE test procedures must be the ''Standard Test Method for Measuring the Energy Consumption of Distribution Transformers'' prescribed by the National Electrical Manufacturers Association (NEMA TP 2–1998), subject to review and revision by the Secretary of Energy in accordance with certain criteria and conditions. (42 U.S.C. 6293(b)(10), 6314(a)(2)–(3) and 6317(a)(1)) Manufacturers of such covered equipment must use the prescribed DOE test procedure as the basis for certifying to DOE that their equipment complies with the applicable energy conservation standards adopted under EPCA and when making representations to the public regarding the energy use or efficiency of those types of equipment. (42 U.S.C. 6314(d)) The DOE test procedures for distribution transformers appear at title 10 of the Code of Federal Regulations (CFR) part 431, subpart K, appendix A.

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

1. The economic impact of the standard on manufacturers and customers of the equipment subject to the standard;

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

3. The total projected amount of energy, or as applicable, water, savings likely to result directly from the imposition of the standard;

4. Any lessening of the utility or the performance of the covered equipment 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 and water conservation; and

7. Other factors the Secretary of Energy (Secretary) considers relevant. (42 U.S.C. 6295(o)(2)(B)(i) and 6316(a))

EPCA, as codified, also contains what is known as an ''anti-backsliding'' provision, which prevents the Secretary from prescribing any amended standard that either increases the maximum allowable energy use or decreases the minimum required energy efficiency of a covered product. (42 U.S.C. 6295(o)(1) and 6316(a)) Also, the Secretary may not prescribe an amended or new standard if interested persons have established by a preponderance of the evidence that the standard is likely to result in the unavailability in the United States of any covered product type (or class) of performance characteristics (including reliability, features, sizes, capacities, and volumes) that are substantially the same as those generally available in the United States. (42 U.S.C. 6295(o)(4) and 6316(a))

Further, EPCA, as codified, establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the customer of purchasing equipment complying with an energy conservation standard level will be less than three times the value of the energy savings during the first year that the customer will receive as a result of the standard, as calculated under the applicable test procedure. See 42 U.S.C. 6295(o)(2)(B)(iii) and 6316(a).

Additionally, 42 U.S.C. 6295(q)(1), as applied to covered equipment under 42 U.S.C. 6316(a), specifies requirements when promulgating a standard for a type or class of covered equipment that has two or more subcategories. DOE must specify a different standard level than that which applies generally to such type or class of equipment for any group of covered equipment that has the same function or intended use if DOE determines that equipment within such group: (A) Consumes a different kind of energy from that consumed by other covered equipment within such type (or class); or (B) has a capacity or other performance-related feature which other equipment within such type (or class) does not have and such feature justifies a higher or lower standard. (42 U.S.C. 6295(q)(1) and 6316(a)) In determining whether a performance-related feature justifies a different standard for a group of equipment, DOE must consider such factors as the utility to the customer of such a feature and other factors DOE deems appropriate. *Id.* Any rule prescribing such a standard must include an explanation of the basis on which such higher or lower level was established. (42 U.S.C. 6295(q)(2) and 6316(a))

Federal energy conservation requirements generally supersede State laws or regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6297(a)–(c) and 6316(a)) DOE may, however, grant waivers of Federal preemption for particular State laws or regulations, in accordance with the procedures and other provisions set forth under 42 U.S.C. 6297(d)).

DOE has also reviewed this regulation pursuant to Executive Order (EO) 13563, issued on January 18, 2011 (76 FR 3281, January 21, 2011). EO 13563 is supplemental to and explicitly reaffirms the principles, structures, and definitions governing regulatory review established in EO 12866. To the extent permitted by law, agencies are required by EO 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing

Transformers'' published by the National Electrical Manufacturers Association (NEMA TP 1–2002).

information upon which choices can be made by the public.

DOE emphasizes as well that EO 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. For the reasons stated in the preamble, DOE believes that today's final rule is consistent with these principles, including the requirement that, to the extent permitted by law, benefits justify costs and that net benefits are maximized. Consistent with EO 13563, and the range of impacts analyzed in this rulemaking, the energy efficiency standard adopted herein by DOE achieves maximum net benefits.

B. Background

1. Current Standards

On August 8, 2005, EPACT 2005 amended EPCA to establish energy conservation standards for low-voltage dry-type distribution transformers (LVDTs).[11] (EPACT 2005, Section 135(c); 42 U.S.C. 6295(y)) The standard levels for low-voltage dry-type distribution transformers appear in Table II.1. See Table I.6 above for today's amended LVDT standards.

TABLE II.1—FEDERAL ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency %	kVA	Efficiency %
15	97.7	15	97.0
25	98.0	30	97.5
37.5	98.2	45	97.7
50	98.3	75	98.0
75	98.5	112.5	98.2
100	98.6	150	98.3
167	98.7	225	98.5
250	98.8	300	98.6
333	98.9	500	98.7
		750	98.8
		1,000	98.9

Note: Efficiencies are determined at the following reference conditions: (1) for no-load losses, at the temperature of 20 °C, and (2) for load losses, at the temperature of 75 °C and 35% of nameplate load.

DOE incorporated these standards into its regulations, along with the standards for several other types of products and equipment, in a final rule published on October 18, 2005. 70 FR 60407, 60416–60417. These standards appear at 10 CFR 431.196(a).

On October 12, 2007, DOE published a final rule that established energy conservation standards for liquid-immersed distribution transformers and medium-voltage dry-type distribution transformers, which are shown in Table II.2 and Table II.3, respectively. 72 FR 58190, 58239–40. These standards are codified at 10 CFR 431.196(b) and (c). See Tables I.5 and I.7 above for today's amended liquid-immersed and medium-voltage dry-type (MVDT) standards.

TABLE II.2—FEDERAL ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency %	kVA	Efficiency %
10	98.62	15	98.36
15	98.76	30	98.62
25	98.91	45	98.76
37.5	99.01	75	98.91
50	99.08	112.5	99.01
75	99.17	150	99.08
100	99.23	225	99.17
167	99.25	300	99.23
250	99.32	500	99.25
333	99.36	750	99.32
500	99.42	1,000	99.36
667	99.46	1,500	99.42
833	99.49	2,000	99.46
	....	2,500	99.49

Note: All efficiency values are at 50% of nameplate-rated load, determined according to the DOE test-procedure. 10 CFR part 431, subpart K, appendix A.

[11] EPACT 2005 established that the efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2007, shall be the Class I Efficiency Levels for distribution transformers specified in Table 4–2 of the ''Guide for Determining Energy Efficiency for Distribution Transformers'' published by the National Electrical Manufacturers Association (NEMA TP 1–2002).

TABLE II.3—FEDERAL ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

kVA	Single-phase			kVA	Three-phase		
	BIL*				BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency %	Efficiency %	Efficiency %		Efficiency %	Efficiency %	Efficiency %
15	98.10	97.86		15	97.50	97.18	
25	98.33	98.12		30	97.90	97.63	
37.5	98.49	98.30		45	98.10	97.86	
50	98.60	98.42		75	98.33	98.12	
75	98.73	98.57	98.53	112.5	98.49	98.30	
100	98.82	98.67	98.63	150	98.60	98.42	
167	98.96	98.83	98.80	225	98.73	98.57	98.53
250	99.07	98.95	98.91	300	98.82	98.67	98.63
333	99.14	99.03	98.99	500	98.96	98.83	98.80
500	99.22	99.12	99.09	750	99.07	98.95	98.91
667	99.27	99.18	99.15	1,000	99.14	99.03	98.99
833	99.31	99.23	99.20	1,500	99.22	99.12	99.09
				2,000	99.27	99.18	99.15
				2,500	99.31	99.23	99.20

* BIL means "basic impulse insulation level."

Note: All efficiency values are at 50% of nameplate rated load, determined according to the DOE test-procedure. 10 CFR part 431, subpart K, appendix A.

2. History of Standards Rulemaking for Distribution Transformers

In a notice published on October 22, 1997 (62 FR 54809), DOE stated that it had determined that energy conservation standards were warranted for electric distribution transformers, relying in part on two reports by DOE's Oak Ridge National Laboratory (ORNL). In 2000, DOE issued and took comment on its Framework Document for Distribution Transformer Energy Conservation Standards Rulemaking, describing its proposed approach for developing standards for distribution transformers, and held a public meeting to discuss the framework document. The document is available at: *http://www.regulations.gov/#!docketDetail;dct=FR%252BPR%252BN%252BO%252BSR;rpp=10;po=0;D=EERE-2006-STD-0099*.

On July 29, 2004, DOE published an advance notice of proposed rulemaking (ANOPR) for distribution transformer standards.[12] 69 FR 45375. In August 2005, DOE issued draft analyses on which it planned to base the standards for liquid-immersed and medium-voltage dry-type distribution transformers, along with supporting documentation.[13]

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

On August 4, 2006, DOE published a NOPR in which it proposed energy conservation standards for distribution transformers (the 2006 NOPR). 71 FR 44355. Concurrently, DOE also issued a technical support document (TSD) that incorporated the analyses it had performed for the proposed rule.[14]

Some commenters asserted that DOE's proposed standards might adversely affect replacement of distribution transformers in certain space-constrained (e.g., vault) installations. In response, DOE issued a notice of data availability and request for comments on this and another issue. 72 FR 6186 (February 9, 2007) (the NODA). In the NODA, DOE sought comment on whether it should include in the LCC analysis potential costs related to size constraints of distribution transformers installed in vaults, and requested comments on linking energy efficiency levels for three-phase liquid-immersed units with those of single-phase units. 72 FR 6189. Based on comments on the 2006 NOPR and the NODA, DOE created new TSLs to address the treatment of three-phase units and single-phase units and incorporated increased installation costs for pole-mounted and vault transformers. In October 2007, DOE published a final rule that created the current energy conservation standards for liquid-immersed and medium-voltage dry-type distribution transformers. 72 FR 58190 (October 12, 2007) (the 2007 Final Rule) (codified at 10 CFR 431.196(b)–(c)). The preamble to the rule included additional, detailed background information on the history of that rulemaking. 72 FR 58194–96.

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

[12] The ANOPR published in July 2004 is available at: *http://www.regulations.gov/#!documentDetail;D=EERE-2006-STD-0099-0069*.

[13] These analyses are available in the docket folder at: *http://www.regulations.gov/#!docketDetail;D=EERE-2006-STD-0099*.

[14] The NOPR TSD published in August 2006 is available at: *http://www.regulations.gov/#!documentDetail;D=EERE-2006-STD-0099-0140*.

immersed and medium-voltage dry-type distribution transformers. Under the original settlement agreement, DOE was required to publish by October 1, 2011, either a determination that the standards for those distribution transformers do not need to be amended or a NOPR that includes any new proposed standards and that meets all applicable requirements of EPCA and NEPA. Under an amended settlement agreement, the October 1, 2011, deadline for a DOE determination or proposed rule was extended to February 1, 2012. If DOE finds that amended standards are warranted, DOE agreed to publish a final rule containing such amended standards by October 1, 2012. Today's final rule satisfies the amended settlement agreement.

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

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

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

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

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

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

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

For medium-voltage dry-type distribution transformers, the subcommittee arrived at consensus and recommended a proposed standard of EL2 for DLs 11 and 12, from which the proposed standards for DLs 9, 10, 13A, and 13B would be scaled. Transcripts of the all subcommittee meetings (for all transformer types) and all data and materials presented at the subcommittee meetings are available via a link under the DOE Web site at: *http://www.regulations.gov/#!docketDetail;D=EERE-2010-BT-STD-0048*.

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

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

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

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

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

DOE published a NOPR on February 10, 2012, which proposed amended standards for all three transformer types. 77 FR 7282. Medium-voltage dry-type distribution transformers were proposed at the negotiating committee's consensus level. Liquid-immersed distribution transformers were proposed at TSL 1. Low-voltage dry-type distribution transformers were proposed at TSL 1. In the NOPR, DOE sought comment on a number of issues related to the rulemaking.[15]

Following publication of the NOPR, DOE received several comments expressing a desire to see some of the NOPR suggestions extended and analyzed for liquid-immersed distribution transformers. In response, DOE generated a supplementary NOPR analysis with three additional TSLs. The three TSLs presented were based on possible new equipment classes for pole-mounted distribution transformers, network/vault-based distribution transformers, and those with high basic impulse level (BIL) ratings. On June 4, 2012 DOE published a notice announcing the availability of this supplementary analysis[16] and of a public meeting to be held on June 20, 2012 to present and receive feedback on it. DOE also generated an additional TSL in a June 18, 2012 analysis published on DOE's Web site.

III. General Discussion

A. Test Procedures

DOE published its test procedure for distribution transformers in the **Federal Register** as a final rule on April 27, 2006. 71 FR 24972. Section 7(c) of the Process Rule[17] indicates that DOE will issue a final test procedure, if one is needed, prior to issuing a proposed rule for energy conservation standards. Under 42 U.S.C. 6314(a)(1), at least every seven years, DOE must evaluate whether to amend test procedures for each class of commercial equipment based on whether an amended test procedure would more accurately or fully comply with the requirements that test procedures be reasonably designed to produce test results that reflect energy efficiency, energy use, and estimated operating costs during a representative average use cycle, and that the test procedures are not unduly burdensome to conduct.[18] Any determination that a test procedure amendment is not required under this standard must be published in the **Federal Register**. (42 U.S.C. 6314(a)(1)(A)(ii))

As detailed below, in today's notice, DOE determines that an amended test procedure is not necessary because the 2006 test procedure is reasonably designed to produce test results that reflect energy efficiency and energy use, and an amended test procedure that more precisely measures energy efficiency and energy use for every possible distribution transformer configuration would be unduly burdensome to conduct.

1. General

Several parties commented on the test procedure for distribution transformers. The California Investor Owned Utilities (CA IOUs) commented that DOE should not modify the test procedure. (CA IOUs, No. 189 at p. 1) Today's rule contains no test procedure amendments, but the rule does clarify the test procedure's application in response to comments. DOE may revisit the issue of test procedures in a future proceeding.

NEMA commented that because of variability in process, materials, and testing, manufacturers must ''overdesign'' transformers in order to have confidence that their products will meet standards. (NEMA, No. 170 at p. 3) DOE notes that its compliance procedures already contain allowances for statistical variation as a result of measurement, laboratory, and testing procedure variability. Manufacturers are also required to take certification sampling plans and tolerances into account when developing their certified ratings after testing a sample of minimum units from the production of a basic model. The represented efficiency equation essentially allows a manufacturer to ''represent'' a basic model of distribution transformer as having achieved a higher efficiency than calculated through testing the minimum sample for certification. DOE is not adopting any modifications to its certification or enforcement sampling procedures in this final rule, but it may further address them in a separate proceeding at a later date if it finds such practices to be overly strict or generous.

Additionally, Schneider Electric commented that DOE's test procedure is inadequate or ambiguous in several areas, including test environment drafts, ambient method internal temperatures, test environment ambient temperature variation, ambient method test delays,

[15] On February 24, 2012, DOE published a technical correction to the NOPR, amending and adding values in certain tables in the NOPR. 77 FR 10997.

[16] 77 FR 32916.

[17] The Process Rule provides guidance on how DOE conducts its energy conservation standards rulemakings, including the analytical steps and sequencing of rulemaking stages (such as test procedures and energy conservation standards). (10 CFR Part 430, subpart C, appendix A).

[18] In addition, if the test procedure determines estimated annual operating costs, such procedure must meet additional requirements at 42 U.S.C. 6314(a)(3).

coordination of coil and ambient test methods, temperature data records, and application of voltage or current. (Schneider, No. 180 at p. 12) DOE examined the test procedure components identified by Schneider Electric and determined that, at this time, no change to the test procedure is necessary to address the issues raised. Further, the existing, statutorily-prescribed test procedure is an industry standard familiar to manufacturers. DOE continues to believe that the procedure is reasonably designed to produce test results that reflect energy efficiency and energy use without being unduly burdensome to conduct.

Finally, DOE's present sampling plans require a minimum number of units be tested in order to calculate the represented efficiency of a basic model. (10 CFR 429.47 (a)). Prolec-GE commented that DOE's compliance protocols allow too small a statistical variation, particularly because silicon steel sees a greater variation in losses than does the amorphous variety. (Prolec-GE, No. 177 at p. 17) To the extent Prolec-GE is concerned about the variability in their production, DOE notes that the statistical sampling plans allow for manufacturers to increase the sample size, which should help better characterize the variability association with the production. DOE's existing sampling plans are a balance between manufacturing burden associated with testing and accurately characterizing the efficiency of a given basic model based on a sample of the production. While DOE is not adopting any changes to its existing sampling plans in today's final rule, DOE welcomes data showing the production variability for different types and efficiencies of distribution transformers to help better inform any changes that may be considered in a separate and future proceeding.

2. Multiple kVA Ratings

The current test procedure is not specific regarding which kVA rating should be used to assess compliance in the case of distribution transformers that have more than one rating. Though less common in distribution transformers than in other types of transformers (e.g., ''power'' or ''substation'' transformers), active cooling measures such as fans or pumps are sometimes used to aid cooling. Greater heat dissipation capacity means that the transformer can be safely operated at higher loading levels for longer periods of time. Active cooling components generally carry much shorter lifetimes than the transformer itself, however, and the failure of any cooling component would expose the transformer at-large to premature failure due to elevated temperatures. Accordingly, distribution transformers rarely contain such components and, when they do, rarely make use of them except in occasional overload situations. As a result, they play little role in the design of the transformer or in a transformer's ability to operate efficiently even when equipped.

Apart from ratings corresponding to active cooling, transformers may also carry additional ratings (i.e., above the ''base rating'') corresponding to passive cooling and reflecting different temperature rises. A transformer would be rated for higher kVA if allowed to rise to a greater temperature and, by extension, dissipate more energy.

DOE sought comment on whether the test procedure needs greater specificity with respect to multiple kVA ratings. No party argued that distribution transformers should comply with standards at any ratings corresponding to active cooling, for the reasons discussed above. Four manufacturers (Howard Industries, Cooper Power Systems, Prolec-GE, and Schneider Electric), one trade organization (NEMA), and one utility (Progress Energy) all commented that compliance should be based exclusively on a transformer's ''base'' rating, or the rating that corresponds to the lowest temperature rise. (Prolec-GE, No. 177 at p. 6; Schneider, No. 180 at p. 2; PEMCO, No. 183 at p. 2; PE, No. 192 at p. 3; HI, No. 151 at p. 12; NEMA, No. 170 at pp. 6–7) ABB argued that compliance should be based on a transformer's base rating and on any others (if any) corresponding to passive cooling. (ABB, No. 158 at pp. 2–4) HVOLT commented that the term ''passive cooling'' may not be sufficient to clarify DOE's intent because some transformers have more than one rating which may be achieved with passive cooling. (HVOLT, No. 146 at p. 49)

Though prevalent in certain types of larger transformers, active cooling is not a significant feature in the design or operation of distribution transformers. Distribution transformers are seldom equipped with active cooling features or designed to make use of them. Additionally, units which are equipped with such features are rarely operated using them. As a result, active cooling features bear little influence on transformer efficiency and are not appropriate for use in measuring energy efficiency. Similarly, transformers with more than one rating corresponding to passive cooling will experience reduced equipment lifetime when operated at those high ratings and are therefore best evaluated at their lowest, ''base'' rating. DOE clarifies today that manufacturers should use a transformer's base kVA rating to assess compliance. For distribution transformers with more than one kVA rating, base kVA rating means the kVA rating that corresponds to the lowest temperature rise that actively removes heat from the distribution transformer without engagement of any fans, pumps, or other equipment. It is the base kVA rating and the base kVA rating only, which manufacturers should base their certified ratings on and on which DOE will assess compliance. In no case should a distribution transformer be certified using any kVA rating corresponding to heat removal or enhanced convection by auxiliary equipment.

3. Dual/Multiple Basic Impulse Level

Distribution transformers may be built such that different winding configurations carry different BIL ratings. In the past, MVDT transformers were placed into equipment classes by BIL rating (among other criteria) and the question arose of which rating (if there were more than one) should be used to assess compliance. Currently, DOE requires distribution transformers to comply with standards using the BIL rating of the winding configuration that produces the greatest losses. (10 CFR part 431, subpart K, appendix A)

BIL rating offers additional utility in the form of increased resistance to large voltage transients arising, for example, from lightning strikes, but requires some design compromises that affect efficiency, primarily with respect to winding clearances. A transformer rated for a given BIL must be designed as such, even if the windings may be reconfigured such that they carry a lower rating. For this reason, Progress Energy, PEMCO, NEMA, Cooper Power Systems, Power Partners, and Howard Industries all commented that transformers with multiple BIL ratings should comply only at the highest BIL for which they are rated. (HI, No. 151 at p. 12; Power Partners, No. 155 at p. 1–2; Cooper, No. 165 at p. 2; NEMA, No. 170 at p. 7; Prolec-GE, No. 177 at p. 6; PEMCO, No. 183 at p. 2; PE, No. 192 at p. 3) ABB commented that transformers should meet the efficiency levels of all of its rated BILs, because there is no way to know in advance how a transformer will be operated over its lifetime. (ABB, No. 158 at p. 4)

Although DOE agrees there is no way to be sure how a distribution transformer will be operated over its lifetime, it does not believe multiple BIL ratings currently present an energy conservation standards circumvention risk. Designing transformers to higher BIL ratings adds cost and consumers would be unlikely to utilize them unless genuinely required by the application.

DOE clarifies that transformers may be certified at any BIL for which they are rated, including the highest BIL ratings. This does nothing to change DOE's requirement that distribution transformers comply in the configuration that produces the greatest losses, however, even if that configuration itself does not carry the highest BIL rating. For example, a MVDT distribution transformer may have two winding configurations, respectively BIL rated at 60 kV and 125 kV. Although the distribution transformer must meet only the 125 kV standards, it may produce greater losses (and thus need to be certified) in the 60 kV configuration.

4. Dual/Multiple-Voltage Primary Windings

Currently, DOE requires manufacturers to comply with energy conservation standards while the distribution transformer's primary windings (''primaries'') are in the configuration that produces the highest losses. (10 CFR part 431, subpart K, appendix A)

DOE understands that, in contrast to the secondary windings, reconfigurable primaries typically exhibit a larger variation in efficiency between series and primary connections. Such transformers are often purchased with the intent of upgrading the local power grid to a higher operating voltage and lowered overall system losses.

Several parties commented on the matter of primary winding configurations in response to the NOPR. Kentucky Association of Electric Cooperatives (KAEC), Cooper Power Systems, NEMA, and Progress Energy commented that it is least burdensome for manufacturers if they can report losses in the same configuration in which the transformers are shipped, which by Institute of Electrical and Electronics Engineers (IEEE) standards must be the series configuration. (KAEC, No. 149 at p. 2; NEMA, No. 170 at p. 6; PE, No. 192 at p. 10; PE, No. 192 at p. 2; Prolec-GE, No. 177 at p. 5; Schneider, No. 180 at p. 2; Schneider, No. 180 at p. 8; Cooper Power Systems, No. 222 at p. 3) Howard Industries and Prolec-GE commented that manufacturers should be allowed to test distribution transformers with their primaries in any configuration. (HI, No. 151 at p. 12; Prolec-GE, No. 177 at p. 5) Utilities Baltimore Gas and Electric and Commonwealth Edison supported testing in the configuration in which the transformer will ultimately be used. (BG&E, No. 182 at p. 2; ComEd, No. 184 at p. 2)

ABB submitted comments and data explaining that the ratios of the losses of different winding positions varied considerably and, as a result, that there was no reliable way to predict which configuration would carry the lowest losses. ABB and the California IOUs supported maintaining the test procedure's current requirements. (ABB, No. 158 at p. 2; CA IOUs, No. 189 at pp. 1–2)

DOE is concerned that the primary winding configuration can have a significant impact on energy consumption and that by relaxing the restriction of compliance in the configuration producing the highest losses, any forecasted energy savings may be diminished. DOE is not modifying any test procedure requirements in today's rule, but may reexamine the topic in a dedicated test procedure rulemaking in the future.

5. Dual/Multiple-Voltage Secondary Windings

DOE understands that some distribution transformers may be shipped with reconfigurable secondary windings, and that certain configurations may have different efficiencies. Currently, DOE requires distribution transformers to be tested in the configuration that exhibits the highest losses. Whereas the IEEE standard [19] requires a distribution transformer to be shipped with the windings in series, a manufacturer testing for compliance might need to disassemble the unit, reconfigure the windings, and reassemble the unit for shipping at added time and expense.

Several parties commented on the matter of reconfigurable secondary windings. Cooper Power Systems, KAEC, NEMA, Progress Energy, and Schneider Electric supported conducting testing with windings in series, as is the IEEE convention and as would produce the highest voltage. (Cooper, No. 165 at pp. 1–2, 6 No. 222 at p. 3; HI, No. 151 at p. 12; KAEC, No. 149 at p. 2; NEMA, No. 170 at p. 6; PE, No. 192 at p. 10; PE, No. 192 at p. 2; Schneider, No. 180 at p. 2; Schneider, No. 180 at p. 8)

Power Partners and Prolec-GE commented that testing should be permitted in any winding configuration at the discretion of the manufacturer. (Power Partners, No. 155 at p. 1; Prolec-GE, No. 177 at pp. 3–4)

Additionally, ABB and the California IOUs commented that there was no way of knowing which position would produce the greatest losses and, therefore, the test procedure should remain unchanged with respect to winding configuration requirements. (ABB, No. 158 at p. 2; CA IOUs, No. 189 at p. 1–2)

DOE is concerned that secondary windings may have significantly different losses in various configurations and that, furthermore, there is no reliable way to predict in which configuration the transformer will be operated over the majority of its lifetime. Just as with dual/multiple primary windings, changing the requirement of testing in the configuration producing the highest losses, may diminish forecasted energy savings. As a result, DOE is not modifying any test procedure requirements in today's rule, but may reexamine the topic in a dedicated test procedure rulemaking in the future.

6. Loading

Currently, DOE requires that both liquid-immersed and medium-voltage dry-type distribution transformers comply with standards at 50 percent loading and that low-voltage dry-type distribution transformers comply at 35 percent loading. DOE wishes to clarify that the loading discussed herein pertains only to that which manufacturers must use to test their equipment. DOE's economic analysis uses loading distributions that attempt to reflect the most recent understanding of the United States electrical grid. DOE does not believe that all (or the average of all) customers utilize transformers at the required test procedure loading values.

Several parties commented on the appropriateness of these test loading values. ABB, ComEd, Cooper, EEI, Howard, KAEC, NEMA, NRECA, PEMCO, Prolec-GE, and Schneider all commented that the values were appropriate and should continue to be used. (ABB, No. 158 at p. 5; ComEd, No. 184 at p. 2; Cooper, No. 165 at p. 2; EEI, No. 185 at p. 4; HI, No. 151 at p. 12; KAEC, No. 149 at p. 3; NEMA, No. 170 at p. 12; NRECA, No. 172 at p. 4; PEMCO, No. 183 at p. 2; Prolec-GE, No. 177 at p. 7; Schneider, No. 180 at p. 3)

Progress Energy commented that it believed the current values suffice for the present but that DOE should further explore the topic in the future. (PE, No. 192 at p. 3) BG&E commented that utilities had oversized transformers in the past due to lack of ability to accurately monitor loading and that loading will increase in the future. (BG&E, No. 182 at p. 3) Finally, MGLW and the Copper Development

[19] IEEE C57.12.00–2010.

Association commented that DOE should use a test procedure that requires measurements at several loading levels and reporting of efficiency as a weighted average of those. (MLGW, No. 133 at p. 2; CDA, No. 153 at p. 4)

DOE understands that distribution transformers experience a range of loading levels when installed in the field. DOE understands that the majority of stakeholders, including manufacturers and utilities, support retention of the current testing requirements and DOE determined that its existing test procedure provides results that are representative of the performance of distribution transformers in normal use. Although DOE may examine the topic of potential loading points in a dedicated test procedure rulemaking in the future, at this time, DOE does not believe that the potential improvement in testing precision outweighs the complexity and the burden of requiring testing at different loadings depending on each individual transformer's characteristics.

B. Technological Feasibility

1. General

In each standards rulemaking, DOE conducts a screening analysis based on information it has gathered on all current technology options and prototype designs that could improve the efficiency of the products that are the subject of the rulemaking. As the first step in such analysis, DOE develops a list of technology options for consideration in consultation with manufacturers, design engineers, and other interested parties. DOE then determines which of these means for improving efficiency are technologically feasible. DOE considers technologies incorporated in commercially available products or in working prototypes to be technologically feasible. 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i) There are distribution transformers available at all of the energy efficiency levels considered in today's final rule. Therefore, DOE believes all of the energy efficiency levels adopted by today's final rulemaking are technologically feasible.

Once DOE has determined that particular technology options are technologically feasible, it further evaluates each of them in light of the following additional screening criteria: (1) Practicability to manufacture, install, or service; (2) adverse impacts on product utility or availability; and (3) adverse impacts on health or safety. For further details on the screening analysis for this rulemaking, see chapter 4 of the final rule TSD.

2. Maximum Technologically Feasible Levels

When DOE considers an amended standard for a type or class of covered equipment, it must determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible for that equipment. (42 U.S.C. 6295(p)(1); 42 U.S.C. 6316(a)) While developing the energy conservation standards for liquid-immersed and medium-voltage dry-type distribution transformers that were codified under 10 CFR 431.196, DOE determined the maximum technologically feasible (max-tech) energy efficiency level through its engineering analysis. The max-tech design incorporates the most efficient materials, such as core steels and winding materials, and applied design parameters that create designs at the highest efficiencies achievable at the time. 71 FR 44362 (August 4, 2006) and 72 FR 58196 (October 12, 2007). DOE used those designs to establish max-tech levels for its LCC analysis, then scaled them to other kVA ratings within a given design line to establish max-tech efficiencies for all the distribution transformer kVA ratings. For today's rule, DOE determined max-tech in exactly the same manner.

C. Energy Savings

1. Determination of Savings

For each TSL, DOE projected energy savings from the products that are the subject of this rulemaking purchased in the 30-year period that begins in the year of compliance with amended standards (2016–2045). The savings are measured over the entire lifetime of products purchased in the 30-year period.[20] DOE quantified the energy savings attributable to each TSL as the difference in energy consumption between each standards case and the base case. The base case represents a projection of energy consumption in the absence of amended mandatory efficiency standards, and considers market forces and policies that affect demand for more efficient products.

DOE used its national impact analysis (NIA) spreadsheet model to estimate energy savings from amended standards for the products that are the subject of this rulemaking. The NIA spreadsheet model calculates energy savings in site electricity, which is the energy directly consumed by transformers at the locations where they are used. DOE reports national energy savings on an annual basis in terms of the primary energy savings, which is the savings in the energy that is used to generate and transmit the site electricity. To convert site electricity to primary energy, DOE derived annual conversion factors from the model used to prepare the Energy Information Administration's (EIA) *Annual Energy Outlook 2012* (*AEO 2012*). Recent data suggests that electricity related losses, which includes conversion from the primary fuel source and the transmission of electricity, is about twice that of site electricity use.

2. Significance of Savings

As noted above, 42 U.S.C. 6295(o)(3)(B) prevents DOE from adopting a standard for covered equipment if such a standard would not result in significant energy savings. While EPCA does not define the term ''significant,'' the U.S. Court of Appeals for the District of Columbia, in *Natural Resources Defense Council* v. *Herrington,* 768 F.2d 1355, 1373 (DC Cir. 1985), indicated that Congress intended ''significant'' energy savings in this context to be savings that were not ''genuinely trivial.'' The energy savings for all of the TSLs considered in this rulemaking are non-trivial and, therefore, DOE considers them significant within the meaning of EPCA section 325(o).

D. Economic Justification

1. Specific Criteria

As noted previously, EPCA requires DOE to evaluate seven factors to determine whether a potential energy conservation standard is economically justified. (42 U.S.C. 6295(o)(2)(B)(i)) The following sections describe how DOE has addressed each of the seven factors in this rulemaking.

a. Economic Impact on Manufacturers and Consumers

In determining the impacts of an amended standard on manufacturers, DOE first determines the quantitative impacts using an annual cash-flow approach. This includes both a short-term assessment, based on the cost and capital requirements during the period between the issuance of a regulation and when entities must comply with the regulation, and a long-term assessment for a 30-year analysis period. The

[20] In the past DOE presented energy savings results for only the 30-year period that begins in the year of compliance. In the calculation of economic impacts, however, DOE considered operating cost savings measured over the entire lifetime of products purchased in the 30-year period. Because some transformers sold in 2045 will reach the maximum transformer lifetime of 60 years, DOE calculated economic impacts through 2105. DOE has chosen to modify its presentation of national energy savings to be consistent with the approach used for its national economic analysis.

industry-wide impacts analyzed include INPV (which values the industry on the basis of expected future cash flows), cash flows by year, changes in revenue and income. Second, DOE analyzes and reports the impacts on different types of manufacturers, paying particular attention to impacts on small manufacturers. See section VI.B for further discussion. Third, DOE considers the impact of standards on domestic manufacturer employment and manufacturing capacity, as well as the potential for standards to result in plant closures and loss of capital investment. Finally, DOE takes into account cumulative impacts of various DOE regulations and other regulatory requirements on manufacturers.

For individual customers, measures of economic impact include the changes in LCC and the PBP associated with new or amended standards. The LCC, which is separately specified in EPCA as one of the seven factors to be considered in determining the economic justification for a new or amended standard (42 U.S.C. 6295(o)(2)(B)(i)(II)), is discussed in the following section. For customers in the aggregate, DOE also calculates the national NPV of the economic impacts on customers over the forecast period applicable to a particular rulemaking.

b. Life-Cycle Costs

The LCC is the sum of the purchase price of a type of equipment (including its installation) and the operating expense (including energy and maintenance and repair expenditures) discounted over the lifetime of the equipment. The LCC savings for the considered energy efficiency levels are calculated relative to a base case that reflects likely trends in the absence of amended standards. The LCC analysis requires a variety of inputs, such as equipment prices, equipment energy consumption, energy prices, maintenance and repair costs, equipment lifetime, and customer discount rates. DOE assumed in its analysis that customers will purchase the considered equipment in 2016.

To account for uncertainty and variability in specific inputs, such as equipment lifetime and discount rate, DOE uses a distribution of values with probabilities attached to each value. A distinct advantage of this approach is that DOE can identify the percentage of customers estimated to receive LCC savings or experience an LCC increase, in addition to the average LCC savings associated with a particular standard level. In addition to identifying ranges of impacts, DOE evaluates the LCC impacts of potential standards on identifiable subgroups of customers that may be disproportionately affected by a national standard.

c. Energy Savings

Although significant conservation of energy is a separate statutory requirement for imposing an energy conservation standard, EPCA requires DOE, in determining the economic justification of a standard, to consider the total energy savings that are expected to result directly from the standard. (42 U.S.C. 6295(o)(2)(B)(i)(III)) DOE uses the NIA spreadsheet results in its consideration of total projected energy savings.

d. Lessening of Utility or Performance of Equipment

In establishing classes of equipment, and in evaluating design options and the impact of potential standard levels, DOE sought to develop standards for distribution transformers that would not lessen the utility or performance of the equipment. (42 U.S.C. 6295(o)(2)(B)(i)(IV)) None of the TSLs presented in today's final rule would lessen the utility or performance of the equipment under consideration in the rulemaking.

e. Impact of Any Lessening of Competition

EPCA directs DOE to consider any lessening of competition that is likely to result from standards. It also directs the Attorney General of the United States (Attorney General) to determine the impact, if any, of any lessening of competition likely to result from a proposed standard and to transmit such determination to the Secretary, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii)) DOE transmitted a copy of its proposed rule and NOPR TSD to the Attorney General with a request that the Department of Justice (DOJ) provide its determination on this issue. DOJ's response, that the proposed energy conservation standards are unlikely to have a significant adverse impact on competition, is reprinted at the end of this final rule.

f. Need for National Energy Conservation

Certain benefits of the amended standards for distribution transformers are likely to be reflected in improvements to the security and reliability of the Nation's energy system. Reductions in the demand for electricity may also result in reduced costs for maintaining the reliability of the Nation's electricity system. DOE conducted a utility impact analysis, described in section IV.K to estimate how standards may affect the Nation's needed power generation capacity. (See 42 U.S.C. 6295(o)(2)(B)(i)(VI))

Energy savings from the amended standards are also likely to result in environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases associated with energy production. DOE reports the environmental effects from today's standards, and from each TSL it considered, in chapter 15 of the TSD for the final rule. DOE also reports estimates of the economic value of emissions reductions resulting from the considered TSLs (see section IV.M of this final rule).

g. Other Factors

EPCA allows the Secretary of Energy, in determining whether a standard is economically justified, to consider any other factors that the Secretary of Energy considers relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VII)) Under this provision, DOE has also considered the matter of electrical steel availability. This factor is discussed further in sections IV.C.9. and IV.I.5.a.

2. Rebuttable Presumption

As set forth in 42 U.S.C. 6295(o)(2)(B)(iii), EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the customer of a type of equipment that meets the standard is less than three times the value of the first-year of energy savings resulting from the standard, as calculated under the applicable DOE test procedure. DOE's LCC and PBP analyses generate values used to calculate the PBP for consumers of potential amended energy conservation standards. These analyses include, but are not limited to, the three-year PBP contemplated under the rebuttable presumption test. However, DOE routinely conducts an economic analysis that considers the full range of impacts to the customer, manufacturer, Nation, and environment, as required under 42 U.S.C. 6295(o)(2)(B)(i). The results of that analysis serve as the basis for DOE to definitively evaluate the economic justification for a potential standard level (thereby supporting or rebutting the results of any three-year PBP analysis). The rebuttable presumption payback calculation is discussed in sections IV.F.3.j and V.B.1.c of this final rule.

IV. Methodology and Discussion of Related Comments

DOE used two spreadsheet tools to estimate the impact of today's amended standards. The first spreadsheet calculates LCCs and PBPs of potential new energy conservation standards. The second provides shipments forecasts and calculates impacts of potential new energy conservation standards on national NES and NPV. DOE also assessed manufacturer impacts, largely through use of the Government Regulatory Impact Model (GRIM). The two spreadsheets are available online at the rulemaking Web site: *http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/66*.

Additionally, DOE estimated the impacts of energy conservation standards for distribution transformers on utilities and the environment using a version of the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS) for the utility and environmental analyses. The NEMS model simulates the energy sector of the U.S. economy. EIA uses NEMS to prepare its Annual Energy Outlook (*AEO),* a widely known energy forecast for the United States. The version of NEMS used for appliance standards analysis, called NEMS–BT,[21] is based on the *AEO* version with minor modifications.[22] The NEMS–BT offers a sophisticated picture of the effect of standards because it accounts for the interactions between the various energy supply and demand sectors and the economy as a whole.

A. Market and Technology Assessment

For the market and technology assessment, DOE develops information that provides an overall picture of the market for the equipment concerned, including the purpose of the equipment, the industry structure, and market characteristics. This activity includes both quantitative and qualitative assessments, based primarily on publicly available information. The subjects addressed in the market and technology assessment for this rulemaking included scope of coverage, definitions, equipment classes, types of equipment sold and offered for sale, and technology options that could improve the energy efficiency of the equipment under examination. Chapter 3 of the TSD contains additional discussion of the market and technology assessment.

1. Scope of Coverage

This section addresses the scope of coverage for today's final rule, stating what equipment will be subject to amended standards.

a. Definitions

Today's standards rulemaking concerns distribution transformers, which include three categories: Liquid-immersed, low-voltage dry-type (LVDT), and medium-voltage dry-type (MVDT). The definition of a distribution transformer was presented in EPACT 2005, then further refined by DOE when it was codified into 10 CFR 431.192 by the April 27, 2006, final rule for distribution transformer test procedures (71 FR 24972).

Additional detail on the definitions of each of these excluded transformers, which are defined at 10 CFR 431.192, can found in chapter 3 of the TSD.

Many stakeholders expressed support for the defined scope of coverage presented in the NOPR. (ABB, No. 158 at p. 5; Cooper, No. 165 at p. 2; HI, No. 151 at p. 12; KAEC, No. 149 at p. 4; NEMA, No. 170 at p. 8; PEMCO, No. 183 at p. 2; Prolec-GE, No. 177 at p. 7) NRECA pointed out that while some of its members might purchase distribution transformers outside the scope of coverage so few of these types of transformers are made it does not warrant a change in coverage. (NRECA, No. 172 at p. 4–5) Progress Energy agreed, noting that while utilities will occasionally purchase transformers outside of this range, it is a very small percentage of the total number of distribution transformers purchased. (PE, No. 192 at p. 4) EEI was not aware of any of member that purchased units outside of the current defined kVA range. (EEI, No. 185 at p. 5) Finally, BG&E and ComEd noted that DOE has spent a significant amount of time developing efficiency levels for each kVA size and that therefore they supported the current scope. (BG&E, No. 182 at p. 3; ComEd, No. 184 at p. 3) Power Partners was also in support of the current scope, but noted that if separate product classes were established for overhead transformers and network/vault transformers the kVA scope for those product classes should be aligned with the specific requirements for those product standards. (Power Partners, No. 155 at p. 3)

Several stakeholders expressed that additional kVA ranges should be added to the scope of coverage. Specifically, Schneider Electric requested that for LVDT products, the following kVA ranges would add value to the national impact benefits: 1kVA through 500kVA single phase and 3kVA through 1500kVA three phase. (Schneider, No. 180 at p. 4) Similarly, CDA requested an increased range, urging DOE to extend its kVA coverage to sizes about 2,500 kVA. (CDA, No. 153 at p. 2)

Earthjustice expressed concern over sealed and non-ventilating transformers. It felt that these products represented a potential loophole for smaller transformers in DL7 and noted that DOE should revise its definition to ensure these units do not displace covered units. (Earthjustice, No. 195 at p. 6) Similarly, Earthjustice noted revisions to the definition of ''uninterruptible power supply transformer might be necessary'' as some manufacturers are selling exempt UPS units, that are otherwise not covered, for general purpose applications at a cost of 30–40 percent lower than covered transformers. (Earthjustice, No. 195 at p. 6) CDA requested that DOE seek legislation to expand its scope to include power transformers. (CDA, No. 153 at p. 2)

Schneider Electric requested that DOE reevaluate several definitions in its scope of coverage. First, it asked that DOE address its tap ranges and the determination of covered equipment versus products versus exempt equipment to possibly capture further energy savings. Second, it requested that DOE re-evaluate special impedance transformers and ranges. Finally, it noted that because low voltage is limited to 600 volts and below, market conditions have created multiple voltages in the 1.2kV class of equipment, but current standards[23] require this equipment to be evaluated as medium voltage or excluded since the secondary voltage is limited to less than 600 volts. (Schneider, No. 180 at p. 12) Schneider believes that these equipment groups and definitions require reconsideration to prevent circumvention of standards and capture further energy savings.

DOE appreciates the comment on its scope of coverage. With respect to kVA, DOE's current standards are consistent with several NEMA publications. For liquid-immersed and medium-voltage dry-type transformers, both DOE coverage and that of NEMA's TP–1 standard extends to 833 kVA for single-phase units and 2500 kVA for three-phase units. For low-voltage dry-type units, both DOE coverage and that of NEMA's Premium specification extends to 333 kVA for single-phase units and

[21] BT stands for DOE's Building Technologies Program (*http://www1.eere.energy.gov/buildings/*).

[22] The EIA allows the use of the name ''NEMS'' to describe only an AEO version of the model without any modification to code or data. Because the present analysis entails some minor code modifications and runs the model under various policy scenarios that deviate from AEO assumptions, the name ''NEMS–BT'' refers to the model as used here. For more information on NEMS, refer to The National Energy Modeling System: An Overview, DOE/EIA–0581 (98) (Feb. 1998), available at: *http://tonto.eia.doe.gov/FTPROOT/forecasting/058198.pdf.*

[23] *See* 10 CFR 431.196.

1000 kVA for three-phase units. DOE cites these documents as evidence that its kVA scope is consistent with industry understanding. DOE may revise its understanding in the future as the market evolves, but for today's rule maintains the kVA scope proposed in the NOPR.

For sealed and nonventilating transformers, uninterruptible power supply transformers, special impedance transformers, and those with tap ranges of greater than twenty percent, DOE notes that these types of equipment are specifically excluded from standards under EPCA, as amended, 42 USC 6291 (35)(B)(ii)), as codified at 10 CFR 431.192.

Cooper Power systems requested clarification on several points relating to scope of coverage. Some transformers are built with the ability to output at multiple voltages, any number of which may fall within DOE's scope of coverage. For transformers having multiple nominal voltage ratings that straddle the present boundaries of DOE's scope of coverage (i.e., a secondary voltage of 600/1200 volts), Cooper recommended that DOE clarify whether the entire distribution transformer is exempt from efficiency standards. Cooper felt it was unclear if both configurations would have to meet the efficiency standard, neither would meet the standard, or only the secondary voltage of 600 would have to meet the standard. (Cooper Power Systems, No. 222 at p. 3) Second, for three-phase transformers with wye-connected phase windings or single-phase transformers that are rated for externally connecting in a wye configuration, where the phase-to-phase voltage exceeds the present boundaries of the definition of distribution transformer, Cooper requested that DOE clarify that these units are exempt from the standard because the secondary voltage exceeds 600 volts. (Cooper Power Systems, No. 222 at p. 3)

DOE clarifies that the definition of distribution transformer refers to a transformer having an output voltage of 600 volts or less, not having only an output voltage of less than 600 volts. If the transformer has an output of 600 volts or below and meets the other requirements of the definition, DOE considers it to be a distribution transformer within the scope of coverage and therefore subject to standards. This applies equally to transformers with split secondary windings (as in Cooper's first example) and to three-phase transformers where the delta connection may fall below 601 volts and the wye connection may not. DOE also clarifies that once it is determined that a transformer is subject to standards, DOE's test procedure requires that a transformer comply with the standard when tested in the configuration that produces the greatest losses, regardless of whether that configuration alone would have placed the transformer at-large within the scope of coverage under 10 CFR 431.192.

b. Underground and Surface Mining Transformer Coverage

In the October 12, 2007, final rule on energy conservation standards for distributions transformers, DOE codified into 10 CFR 431.192 the definition of an underground mining distribution transformer as follows:

Underground mining distribution transformer means a medium-voltage dry-type distribution transformer that is built only for installation in an underground mine or inside equipment for use in an underground mine, and that has a nameplate which identifies the transformer as being for this use only. 72 FR 58239.

In that same final rule, DOE also clarified that although it believed those transformers were within its scope of coverage, it was not establishing energy conservation standards for underground mining transformers. At the time, DOE recognized that the mining transformers were subject to unique and extreme dimensional constraints that impact their efficiency and performance capabilities. Therefore, DOE established a separate equipment class for mining transformers and stated that it might consider energy conservation standards for such transformers at a later date. Although DOE did not establish energy conservation standards for such transformers, it also did not add underground mining transformers to the list of excluded transformers in the definition of a distribution transformer. DOE maintained that it had the authority to cover such equipment if, during a later analysis, it found technologically feasible and economically justified energy conservation standard levels. 72 FR 58197.

Several stakeholders commented on DOE's definition for mining transformers during the current rulemaking. Joy Global Surface Mining recommended that surface mining transformers be added to the exemption list under the following definition: ''Surface mining transformer is a medium-voltage dry-type distribution transformer that is built only for installation in a surface mine, on-board equipment for use in a surface mine or for equipment used for digging or drilling above ground. It shall have a nameplate which identifies the transformer as being for this use only.'' (Joy Global Surface Mining, No. 214 at p. 1) ABB and PEMCO agreed that ordinary (i.e., non-surface) mining transformers should be moved to the exclusion list in 10 CFR 431.192 (5). (ABB, No. 158 at p. 5; PEMCO, No. 183 at p. 2) PEMCO felt strongly that underground mining transformers should be in the list of transformers excluded from the efficiency standard, pointing out that ''underground mining transformers require the use of much heavier cores and thus have an even larger reason to be excluded than some product types already excluded.'' (PEMCO, No. 183 at p. 2) NEMA commented that all underground mining transformers should be made exempt from the DOE energy efficiency regulation for MVDT due to the special circumstances they must operate under; dimensions and weight are critical for these products, and to reduce the weight and size these transformers are operated near full load, therefore, compliance with DOE regulation will not optimize efficiency. (NEMA, No. 170 at p. 11) Cooper Power suggested that DOE expand the definition of mining transformers to include both liquid filled and dry-type transformers, and specify that this only applies to transformers used inside the mine itself; Cooper supports the exclusion of these transformers from efficiency standards. (Cooper, No. 165 at p. 2) ABB asserted that the definition of mining transformers should be expanded to include transformers used for digging or tunneling. Furthermore, ABB asserted that such equipment should be moved to the exclusion list in 10 CFR 431.192 (5). (ABB, No. 158 at p. 6)

DOE has learned from comments received throughout the rulemaking that mining transformers are subject to several constraints that are not usually concerns for transformers used in general power distribution. Because space is critical in mines, an underground mining transformer may be at a considerable disadvantage in meeting an efficiency standard. Underground mining transformers are further disadvantaged by the fact that they must supply power at several output voltages simultaneously. For today's rule, DOE will again set no standards for underground mining transformers but expands this treatment to include surface mining transformers. Moreover, as commenters point out, surface mining transformers are used to operate specialized machinery which carries space constraints of its own. Furthermore, mining transformers in general perform a role that may differ from general power distribution in many regards, including lifetime, loading, and often the need to supply power at several voltages simultaneously. As DOE had intended its prior determination regarding mining transformers to apply to all mining activities, for today's rule, DOE will again set no standards for underground mining transformers but clarify that this determination also applies to surface mining transformers. Thus, DOE has amended the definition of ''mining transformer'' to include surface mining transformers.

In view of the above, DOE recognizes a potential means to circumvent energy efficiency standards requirements for distribution transformers. Therefore, DOE continues to leave both underground and surface mining transformers off of the list of distribution transformers that are not covered under 10 CFR 431.192, but instead reserve a separate equipment class for mining transformers. DOE may set standards in the future if it believes that underground or surface mining transformers are being purchased as a way to circumvent energy conservation standards for distribution transformers otherwise covered under 10 CFR 431.192.

c. Step-Up Transformers

In the 2012 NOPR, DOE proposed to continue to not set standards for step-up transformers, as these transformers are not ordinarily considered to be performing a power distribution function. However, DOE was aware that step-up transformers may be able to be used in place of step-down transformers (i.e., by operating them backwards) and may represent a potential means to circumvent any energy efficiency requirements as standards increase. In the NOPR, DOE requested comment regarding this issue.

Many stakeholders expressed support for adding step-up transformers to the scope of coverage. Howard Industries commented that there is no practical reason for excluding these transformers, and that DOE should require step-up transformers to meet the same efficiency as step-down, as long as either the output or input voltage is 600 volts or less. They expressed concern that eliminating these transformers would present a potential loophole. (HI, No. 151 at p. 12) Prolec-GE agreed, noting that to eliminate this loophole, step-up transformers should at least indicate their purpose on their nameplates. (Prolec-GE, No. 146 at pp. 55–56) However, Earthjustice commented that simply requiring nameplates for these transformers would be unlikely to deter some users from installing step-up transformers in place of covered transformers. They expressed their concern that DOE had not addressed potential loopholes that had been identified in the rulemaking. (Earthjustice, No, 195 at pp. 5–6) Advocates agreed with comments made during negotiations arguing that step-up transformers should be covered by new standards due to similarities to distribution transformer that could easily lead to substitution and circumvention. (Advocates, No. 186 pp. 5–6) Finally, Berman Economics commented that because step-up transformers had not been included in the 2007 final rule, leaving them uncovered may lead to unintended circumvention. (Berman Economics, No. 221 at p. 7)

Other stakeholders expressed their support for DOE's decision to not separately define and set standards for step-up transformers. (Cooper, No. 165 at p. 2; NEMA, No. 170 at p. 8; BG&E, No. 182 at p. 3) APPA and EEI agreed, pointing out that while in emergency conditions one can occasionally see a step-up transformer used as a step-down transformer, these situations are rare and overall do not result in significant transformer efficiency loss. (APPA, No. 191 at p. 6; EEI, No. 185 at p. 5–6) Progress Energy commented similarly, noting that they do not purchase step-up transformers for use as step-down transformers. (PE, No. 192 at p. 4) ABB and Prolec-GE agreed with the decision to not set separate standards for step-up transformers but requested that these transformers be identified on their nameplate uniformly across the industry. (ABB, No. 158 at p. 6; Prolec-GE, No. 177 at p. 7) PEMCO commented that no action was necessary as the product class falls outside the current definition of a distribution transformer. (PEMCO, No. 183 at p. 2) Schneider Electric sought clarification given the existing definition in section 431.192 and noted that the current standards do not exclude step-up LVDT transformers as written. (Schneider, No. 180 at p. 4)

For today's rule, DOE continues to consider step-up transformers as equipment that is not covered, because they do not perform a function traditionally viewed as power distribution. Transformer coverage is not determined simply based on whether the transformer is stepping voltage up or down. DOE clarifies that liquid-immersed step-up transformers usually fall outside of the rulemaking scope of coverage because of limits on input and output voltage, and not because they are excluded per se. Liquid-immersed and medium-voltage dry-type transformers tend to fall within DOE's scope of coverage only if stepping down voltage because the input voltage upper limit (34.5 kV) is much greater than the output voltage limit (600 V). No such distinction exists for LVDT transformers, which are covered for input and output voltages of 600 V or below, regardless of whether stepping voltage up or down. Nonetheless, because of the circumvention risk, DOE will monitor the use of step-up transformers and consider establishing standards for them, if warranted.

d. Low-Voltage Dry-Type Distribution Transformers

10 CFR 431.192 defines the term ''low-voltage dry-type distribution transformer'' to be a distribution transformer that has an input voltage of 600 V or less; is air-cooled; and does not use oil as a coolant.

Because EPACT 2005 prescribed standards for LVDTs, which DOE incorporated into its regulations at 70 FR 60407 (October 18, 2005) (codified at 10 CFR 431.196(a)), LVDTs were not included in the 2007 standards rulemaking. As a result, the settlement agreement following the publication of the 2007 final rule does not affect LVDT standards. Without regard to whether DOE may have a statutory obligation to review standards for LVDTs, DOE has analyzed all three transformer types and is proposing standards for each in this rulemaking.

e. Negotiating Committee Discussion of Scope

Negotiation participants noted that both network/vault transformers and ''data center'' transformers may experience disproportionate difficulty in achieving higher efficiencies because of certain features that may affect consumer utility. (ABB, Pub. Mtg. Tr., No. 89 at p. 245) In the NOPR, DOE reprinted definitions for these terms, which were proposed at various points by committee members. 77 FR 7301. DOE sought comment in its NOPR about whether it would be appropriate to establish separate equipment classes for any of the following types and, if so, how such classes might be defined such that it was not financially advantageous for customers to purchase transformers in either class for general use. Please see IV.A.2.c for further discussion of DOE's equipment classes in today's final rule.

2. Equipment Classes

DOE divides covered equipment into classes by: (a) The type of energy used; (b) the capacity; and/or (c) any performance-related features that affect consumer utility or efficiency. (42 U.S.C. 6295(q)) Different energy conservation standards may apply to different equipment classes (ECs). For the preliminary and NOPR analyses, DOE analyzed the same 10 ECs as were used in the previous distribution transformers energy conservation standards rulemaking.[24] These 10 equipment classes subdivided the population of distribution transformers by:

(a) Type of transformer insulation—liquid-immersed or dry-type,

(b) Number of phases—single or three,

(c) Voltage class—low or medium (for dry-type units only), and

(d) Basic impulse insulation level (for medium-voltage dry-type units only).

On August 8, 2005, the President signed into law EPACT 2005, which contained a provision establishing energy conservation standards for two of DOE's equipment classes—EC3 (low-voltage, single-phase dry-type) and EC4 (low-voltage, three-phase dry-type). With standards thereby established for low-voltage dry-type distribution transformers, DOE no longer considered these two equipment classes for standards during the 2007 final rule. In today's rulemaking, however, DOE has decided to address all three types of distribution transformers and is establishing new standards for all three types of distribution transformers, including low-voltage dry-type distribution transformers. Table IV.1 presents the ten equipment classes proposed in the NOPR and finalized in this rulemaking and provides the associated kVA range with each.

TABLE IV.1—DISTRIBUTION TRANSFORMER EQUIPMENT CLASSES

EC	Insulation	Voltage	Phase	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	15–833 kVA
6	Dry-type	Medium	Three	20–45kV	15–2500 kVA
7	Dry-type	Medium	Single	46–95kV	15–833 kVA
8	Dry-type	Medium	Three	46–95kV	15–2500 kVA
9	Dry-type	Medium	Single	≥ 96kV	75–833 kVA
10	Dry-type	Medium	Three	≥ 96kV	225–2,500 kVA

a. Less-Flammable Liquid-Immersed Transformers

During the previous rulemaking, DOE solicited comments about how it should treat distribution transformers filled with an insulating fluid of higher flash point than that of traditional mineral oil. 71 FR 44369 (August 4, 2006). Known as ''less-flammable, liquid-immersed'' (LFLI) transformers, these units are marketed to some applications where a fire would be especially costly and traditionally served by the dry-type market, such as indoor applications.

During preliminary interviews with manufacturers, DOE was informed that LFLI transformers might offer the same utility as dry-type transformers since they were unlikely to catch fire. Manufacturers also stated that LFLI transformers could have a minor efficiency disadvantage relative to traditional liquid-immersed transformers because their more viscous insulating fluid requires more internal ducting to properly circulate.

In the October 2007 standards final rule, DOE determined that LFLI transformers should be considered in the same equipment class as traditional liquid-immersed transformers. DOE concluded that the design of a transformer (i.e., dry-type or liquid-immersed) was a performance-related feature that affects the energy efficiency of the equipment and, therefore, dry-type and liquid-immersed should be analyzed separately. Furthermore, DOE found that LFLI transformers could meet the same efficiency levels as traditional liquid-immersed units. As a result, DOE did not separately analyze LFLI transformers, but relied on the analysis for the mineral oil liquid-immersed transformers. 72 FR 58202 (October 12, 2007).

DOE revisited the issue in this rulemaking in light of additional research on LFLI transformers and conversations with manufacturers and industry experts. DOE first considered whether LFLI transformers offered the same utility as dry-type equipment, and came to the same conclusion as in the last rulemaking. While LFLI transformers can be used in some applications that historically use dry-type units, there are applications that cannot tolerate a leak or fire. In these applications, customers assign higher utility to a dry-type transformer. Since LFLI transformers can achieve higher efficiencies than comparable dry-type units, combining LFLIs and dry-types into one equipment class may result in standard levels that dry-type units are unable to meet. Therefore, DOE decided not to analyze LFLI transformers in the same equipment classes as dry-type distribution transformers.

Similarly, DOE revisited the issue of whether or not LFLI transformers should be analyzed separately from traditional liquid-immersed units. DOE concluded, once again, that LFLI transformers could achieve any efficiency level that mineral oil units could achieve. Although their insulating fluids are slightly more viscous, this disadvantage has little efficiency impact and diminishes as efficiency increases and heat dissipation requirements decline. Furthermore, at least one manufacturer suggested that LFLI transformers might be capable of higher efficiencies than mineral oil units because their higher temperature tolerance may allow the unit to be downsized and run hotter than mineral oil units. For these reasons, DOE believes that LFLI transformers would not be disproportionately affected by standards set in the liquid-immersed equipment classes. Therefore, DOE did not consider LFLI in a separate equipment class.

b. Pole-Mounted Liquid-Immersed Distribution Transformers

During negotiations and in response to the NOPR, several parties raised the question of whether pole-mounted, pad-mounted, and possibly other types of

[24] See chapter 5 of the TSD for further discussion of equipment classes.

liquid-immersed transformers should be considered in separate equipment classes. For example, pole-mounted distribution transformers may carry differential incremental cost characteristics and face different size and weight constraints than transformers mounted on the ground. They may also have different features, and experience different loading conditions than some other transformer types. These type of questions led DOE to request comment in the NOPR on whether pole-mounted distribution transformers warranted consideration in a separate equipment classes. A number of parties responded. In response to suggestions in these comments, DOE gave more detailed consideration to separating pole-mounted distribution transformers in a supplementary NOPR analysis, announced in a June 4, 2012, Notice of Public Meeting and Data Availability. 77 FR 32916.

APPA, ASAP, BG&E, ComEd, Howard, Progress Energy, Pepco, and Power Partners all supported separation of pole-mounted transformers into separate equipment classes for the above-mentioned reasons. Size and weight was the most commonly-cited reason. (APPA, No. 191 at p. 7, No. 237 at p. 3; ASAP, No. 146 at pp. 69–70; BG&E, No. 146 at p. 69, No. 182 at p. 4; ComEd, No. 184 at p. 8, No. 227 at p. 2; HI, No. 151 at p. 4, No. 226 at p. 1; PE, No. 192 at p. 5, Pepco, No. 146 at p. 68, No. 145 at pp. 2–3; Power Partners, No. 155 at p. 2)

ABB, NEMA, Berman Economics, Cooper, EEI, AK Steel, and KAEC stated that the increase in standards did not warrant separate treatment of pole-mounted transformers, stating that separation adds complexity to the regulation and does not allow manufacturers of both pole-mounted and other types of liquid-immersed distribution transformers to standardize manufacturing and design practices across product lines. (ABB, No. 158 at p. 6; Berman Economics, No. 150 at p. 19, No. 221 at p. 4; Cooper, No. 165 at p. 3; EEI, No. 229 at p. 2; AK Steel, No. 230 at p. 3; KAEC, No. 149 at p. 4; NEMA, No. 170 at p. 12)

The Advocates, NEMA, and Prolec-GE commented that separation may be warranted but only if DOE opted for higher standards than were proposed in the NOPR. (Advocates, No. 158 at p. 13; Prolec-GE, No. 177 at p. 3; NEMA, No. 170 at p. 14)

NEMA further noted that the matter was complicated and that there were advantages to both approaches. (NEMA, No. 225 at p. 4) Finally, EEI and NRECA commented that DOE should explore the matter but in the next rulemaking for distribution transformers. (EEI, No. 185 at p. 7; NRECA, No. 172 at p. 7) NRECA supported the concept of separation, but this support was qualified by concerns that DOE might raise the efficiency levels. (NRECA, No. 172 at pp. 5–6)

Based on the array of views on this issue and the potential energy and cost savings to weigh, DOE conducted further analysis of this of liquid-immersed transformers issue and presented the findings of its supplementary analysis at a public meeting on June 20, 2012. 77 FR 32916 (June 4, 2012). In today's rule, DOE has chosen not to separate pad and pole-mounted transformers. DOE's concerns about steel competitiveness and availability were not resolved through comments in response to both the NOPR and the supplemental analysis. Moreover, the comments did not demonstrate that establishing standards for transformers separated by those on pads and those on poles was superior to the approach taken in the proposed rule. Therefore, DOE chose not to finalize separate standards for pad-mounted transformers in today's final rule. However, DOE appreciates the concerns about allowing manufacturers to standardize manufacturing and design practices across product lines. DOE may consider establishing separate equipment classes for pole-mounted distribution transformers in the future, but at present believes the equipment class structure proposed in the NOPR to be justified for today's final rule.

c. Network and Vault Liquid-Immersed Distribution Transformers

During negotiations, several parties raised the question of whether network, vault, and possibly other types of liquid-immersed transformers should be considered in separate equipment classes. In the 2012 NOPR, DOE considered separating these types of transformers and sought comment from manufacturers on this matter.

In response to the NOPR, many stakeholders commented on separation of network and vault transformers into new equipment classes. Several stakeholders expressed support for separate equipment classes for network and vault transformers, noting that they agreed with the definition put forth by the negotiations working group. (ABB, No. 158 at p. 6; Adams Electrical Coop, No. 163 at p. 2; APPA, No. 191 at p. 6; BG&E, No. 182 at p. 3; BG&E, No. 223 at p. 2; CFCU, No. 190 at p. 1; ConEd, No. 184 at p. 4; EEI, No. 229 at p. 2; KAEC, No. 149 at p. 4; NEMA, No. 146 at p. 67; NEMA, No. 170 at p. 11; NRECA, No. 172 at p. 5; NRECA, No. 228 at pp. 2–3; Power Partners, No. 155 at p. 2) Stakeholders felt that this separate equipment class should have efficiency standards that are unchanged from the levels that have been in effect since January 1, 2010, set in the 2007 final rule. (Cooper, No. 165 at p. 3; Cooper Power Systems, No. 222 at p. 4; EEI, No. 185 at p. 3; NEMA, No. 170 at p. 8; PE, No. 192 at p. 5; Prolec-GE, No. 177 at pp. 7, 12; PE, No. 192 at p. 8)

Many manufacturers noted that network/vault transformers should be separated based on the tight size and space restrictions placed on them. (NEMA, No. 225 at p. 3; Prolec-GE, No. 146 at p. 15; ABB, No. 158 at p. 9) In many cases, manufacturers stated that higher efficiency transformers cannot fit into existing vaults and still maintain required safety and maintenance clearance. (NEMA, No. 170 at p. 3) Stakeholders argued that any increase in size due to increased efficiency standards would eliminate any economic benefit from higher efficiency due to the extremely high costs of modifying existing vault or other underground infrastructure in urban areas. (Adams Electric Coop, No. 163 at p. 2; BG&E, No. 223 at pp. 2–3; ConEd, No. 184 at p. 4; NRECA, No. 172 at p. 3; Pepco, No. 145 at p. 23; ABB, No. 158 at p. 9; Howard Industries, No. 226 at pp. 1–2; APPA, No. 191 at p. 4; Pepco, No. 145 at p. 3; ConEd, No. 236 at pp. 1–2) Others pointed out that expansion of vaults and manholes in city environments is sometimes even physically impossible due to space constraints. (ConEd, No. 184 at p. 4) Howard Industries noted that often American National Standards Institute (ANSI) standards govern the sizes of these types of transformers based on established maximum dimensional constraints due to vault sizing. (HI, No. 151 at p. 3) Prolec-GE commented that the application of these transformers not only requires them to be compact, but also built to a much higher level of ruggedness and durability. (Prolec-GE, No. 238 at pp. 1–2)

Con Edison, who is the largest user of network- and vault-based distribution transformers in the United States, pointed out that while it agrees with separation of network-based transformers, modifications were needed to the definition presented in Appendix 1–A to include transformers purchased by Con Edison, who is the largest user of network- and vault-based distribution transformers in the United States. (ConEd, No. 236 at p. 2)

Other stakeholders noted that while network and vault transformers could experience dimensional problems at higher efficiencies, these problems are diminished at lower levels. Berman Economics notes that ''the *de minimis* increase in efficiency proposed by DOE in this NOPR do not appear to warrant any such special treatment.'' (Berman Economics, No. 150 at p. 21) ASAP agreed, noting that if the final rule efficiency levels stayed as modest as those in the NOPR then separation was not necessary. (ASAP, No. 146 at pp. 66–67)

Multiple stakeholders expressed hesitation about separating vault transformers. Berman Economics recommended that DOE consider a separate class for network transformers only, as the additional electronics and protections required of a networked transformer likely would make it an uneconomic substitute for a non-networked transformer, an argument that could not be made for vault transformers. (Berman Economics, No. 221 at p. 5) Furthermore, Advocates pointed out that vault transformers may be a compliance loophole/risk and, at minimum, nameplate marking that reads ''For installation in a vault only,'' should be required for this equipment. (Advocates, No. 235 at p. 4) Others noted that the idea of vault transformers being used as substitutes for pad-mounted transformers is ''fraught with over-simplifications and faulty assumptions.'' (APPA, No. 237 at pp. 2–3) They believed that substitution would not occur if DOE defined and carved out network and vault transformers per the IEEE definitions. (APPA, No. 237 at pp. 2–3) It was also pointed out that utilities pay as much as two times as much for a vault transformer as for pad-mounted units of similar capacity. (EEI, No. 229 at p. 5)

DOE appreciates the attention and depth of thought given by stakeholders to this nuanced rulemaking issue. At this time, DOE believes that establishing a new equipment class for network and vault based transformers is unnecessary. It is DOE's understanding that there is no technical barrier that prevents network and vault based transformers from achieving the same levels of efficiency as other liquid-immersed distribution transformers. However, DOE does understand that there are additional costs, besides those to the physical transformer, which may be incurred when a replacement transformer is significantly larger than the original transformer and does not allow for the necessary space and maintenance clearances. Rather than establishing a new equipment class, DOE has considered the costs for such vault replacements in the NIA. Please see section X. Therefore, as stated, DOE is not establishing a new equipment class for these transformer types, but may consider doing so in a future rulemaking.

d. BIL Ratings in Liquid-Immersed Distribution Transformers

During negotiations, several parties raised the question of whether liquid-immersed distribution transformers should have standards set according to BIL rating, as do medium-voltage dry-type distribution transformers. (ABB, Pub. Mtg. Tr., No. 89 at p. 218) Other parties responded in response to the NOPR with suggestions about how to address BIL ratings in liquid-immersed distribution transformers. NEMA pointed out that as BIL increases, a greater volume of core material is needed, adding both expense and no-load losses. (NEMA, No. 170 at p. 4) Cooper agreed with separation by BIL, pointing out that ''standards by BIL level will help differentiate transformers that require more insulation and that are less efficient by nature.'' (Cooper, No. 165 at p. 3) Howard Industries opined that it felt 200 kV BIL and higher transformers should have their own category whose efficiency levels were capped at those set in the 2007 Final Rule. It noted that high BIL ratings require additional insulation to meet American National Standards Institute (ANSI) requirements and such additional insulation limits the achievable efficiency for these transformers. (HI, No. 151 at p. 12) Berman Economics supported separation, and commented that DOE could split at 200 kV if these transformers would not be cheaper than 150 BIL transformers at the newly set standard. (Berman Economics, No. 221 at p. 6) BG&E does not purchase 200 kV BIL transformers but supported maintaining the current 2007 Final Rule efficiency levels for these transformers due to construction and weight limitations. (BG&E, No. 223 at p. 2)

Several stakeholders felt that separate standards should be set for all transformers with a BIL of 150 kV or higher. (NRECA, No. 228 at p. 3; Advocates No. 235 at pp. 4–5; EEI, No. 229 at pp. 5–6; APPA, No. 237 at p. 3) Stakeholders who supported a split at 150 kV felt that all transformers with BILs above this level should not have increasing standards in this rule; the standards should remain at efficiency levels set in the 2007 final rule. (NEMA, No. 225 at p. 3–4; Howard Industries, No. 226 at p. 2) Prolec-GE pointed out that a class of only 200 kV and above is of extremely limited volume and provides no benefit, stating that there is a significant step up in cost for higher efficiencies at 150 kV BIL. (Prolec-GE, No. 238 at p. 2) ''To prevent substitution of higher BIL rated transformers as a means of circumventing the efficiency standard, Cooper recommends using coil voltage as a defining criterion for the 150 kV BIL class. Transformers having an insulation system designed to withstand 150 kV BIL and either a line-to-ground or line-to-neutral voltage that is 19 kV (e.g. 34500GY/19920 or 19920 Delta) or greater would be required to qualify as a true 150 kV BIL distribution transformer.'' (Cooper Power Systems, No. 222 at pp. 3–4)

NEMA and KAEC recommended that the efficiency levels proposed in the NOPR be set for liquid-immersed transformers at 95 kV BIL and below only, while all other BILs remain at the current standard. (NEMA, No. 170 at p. 10; KAEC, No. 149 at p. 5) Prolec-GE agreed that the liquid-immersed transformers should be separated at 95 kV BIL and below and above 95 kV. It also suggested that DOE add more design lines for these equipment classes, as it did not believe the scaling was accurate. (Prolec-GE, No. 177 at p. 8) Power Partners commented that there should be several BIL divisions for liquid-immersed distribution transformers and suggested that DOE have equipment classes for the following: 7200/12470Y 95BIL, 14400/2490Y 125BIL, 19920/34500Y 150BIL, and 34500 200 BIL. (Power Partners, No. 155 at p. 3)

Several stakeholders supported the concept of exploring how BIL affects efficiency but felt that it was not a significant enough issue to delay publication of this rule. They proposed that DOE investigate this concept in the next rulemaking. (PE, No. 192 at p. 6; NRECA, No. 172 at p. 6; EEI, No. 185 at p. 8; ComEd, No. 184 at p. 10; BG&E, No. 182 at p. 5; APPA, No. 191 at p. 7) Similarly, ABB commented that at the current proposed levels, ABB does not recommend moving to a separate BIL range for liquid-immersed transformers. If efficiency levels were to increase, ABB would support a change, but did not feel it is warranted with the proposed levels. (ABB, No. 158 at p. 7) HVOLT agreed that at proposed levels, separating by BIL was likely not needed, and pointed out that efficiency impacts of varied BIL were smaller in liquid-immersed transformers than in dry-type transformers. (HVOLT, No. 146 at p. 73)

DOE appreciates all of the input regarding separating standards for different BIL ratings of liquid-immersed distribution transformers. Similar to network- and vault-based transformers, DOE may give strong consideration to establishing equipment classes by BIL rating when considering increased future standards, but does not perceive a strong technological need for such separation at the efficiency levels under consideration in today's rule and does not, therefore, establish separate equipment classes for liquid-immersed distribution transformers by BIL rating.

e. Data Center Transformers

During negotiations, participants noted that data center transformers may experience disproportionate difficulty in achieving higher efficiencies due to certain features that may affect consumer utility. In the NOPR, DOE proposed the definition below for data center transformers and sought comment both on the definition itself, and whether to separate data center transformers into their own equipment class. It noted that separation, the equipment classes must be defined such that it would not be financially advantageous for consumers to purchase data center transformers for general use.

i. Data center transformer means a three-phase low-voltage dry-type distribution transformer that—

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

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

1. during energizing of the transformer without external devices attached to the transformer that can reduce inrush current;

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

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

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

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

1. Listed as a Nationally Recognized Testing Laboratory (NRTL), under the Occupational Safety and Health Administration, U.S. Department of Labor, for a K-factor rating greater than K–4, as defined in Underwriters Laboratories (UL) Standard 1561: 2011 Fourth Edition, Dry-Type General Purpose and Power Transformers;

2. temperature rise less than 130°C with class 220 [25] insulation or temperature rise less than 110°C with class 200 [26] insulation;

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

4. copper primary and secondary windings;

5. an electrostatic shield; or

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

Several stakeholders responded to the request for comment on data center transformers. HVOLT agreed with the idea of creating a separate equipment class for data center transformers, but noted that ''the concept of the inrush current held to four times rating is not accurate.'' (HVOLT, No. 146 at p. 65) NEMA and KAEC supported the establishment of a separate equipment class for data center transformers as well as the definition developed by the working group and recommended that the efficiency levels for this new class remain at EL0, which is equivalent to the levels of NEMA's standard TP–1 2002. (NEMA, No. 170, at p. 9; KAEC, No. 149 at p. 4 NEMA, No. 170 at p. 5) ABB agreed, noting that it supported the definition developed by the working group and a separate equipment class for LVDT data center transformers. (ABB, No. 158 at p. 6) Cooper Power supported the definition, and recommended that the efficiency level for these transformers remain at the baseline. (Cooper, no. 165 at p. 3) NRECA noted that few of its members serve data centers and that it does not have any data on load factors and peak responsibility factors for data centers, but pointed to Uptime Institute and Lawrence Berkeley National Laboratories as sources that may have such data available. (NRECA, No. 172 at p. 5) Howard Industries commented that this proposal would not directly affect it or its products and until further information is given it could give no response on whether or, so had not there is a necessity for establishing a separate equipment class at this time. (HI, No. 151 at p. 3) Finally, Cooper power suggested that, if a separate definition for data center transformers is adopted, a 75 percent load level should be used in the test procedure. (Cooper, No. 165 at p. 3)

DOE appreciates the comments received about data center transformers. In today's rule, DOE is not establishing separate equipment classes for data center transformers for several reasons. First, after reviewing the proposed definition with technical experts, DOE has come to believe that not all of the listed clauses in the definition are directly related to efficiency as it would pertain to the specific operating environment of a data center. For example, the requirement for copper windings would seem generally to aid efficiency rather than hinder it. Second, DOE believes that there may be risk of circumvention of standards and that a transformer may be built to satisfy the data center definition without significant added expense. Third, DOE understands that operators of data centers are generally themselves interested in equipment with high efficiencies because they often face large electricity costs. If that were true, they may be purchasing at or above today's standard and be unaffected by the rule. Finally, DOE understands that the most significant technical requirement of data center transformers to be related to inrush current. In the worst possible case, DOE understands that operators of data center transformers can (and perhaps already do) take measures to limit inrush current external to the transformer. For these reasons, DOE is not establishing a separate equipment class for data center transformers in today's rule.

f. Noise and Vibration

Progress Energy recommended to DOE that ''any change in efficiency requirements fully investigates the impact of higher sound levels and/or vibration.'' (PE No, 92 at p. 10) Progress Energy noted that higher sound or vibration levels or both will be of significant concern where users are nearby. (PE, No. 192 at p. 10) Southern California Edison reported that it had experienced ferroresonance issues with amorphous core transformers in the past. Further, it expressed ferroresonance concerns about lower loss designs with M2 core steel. (Southern California Edison, No. 239 at p. 1) However, neither EEI nor APPA were aware of vibration or acoustic noise issues associated with higher efficiency transformers but conceded that, if there were to be ferroresonance issues with higher efficiency transformers, it could impact customer satisfaction, especially in residential areas. (EEI, No. 185 at p. 19; APPA, No. 191 at p. 13–14) Cooper Power Systems

[25] International Electrotechnical Commission Standard 60085 Electrical Insulation—Thermal Evaluation and Designation, *3rd edition, 2004, page 11 table 1.*

[26] International Electrotechnical Commission Standard 60085 Electrical Insulation—Thermal Evaluation and Designation, *3rd edition, 2004, page 11 table 1.*

commented that it did not expect that the new standards as proposed will have any negative effect on performance or increase vibration or acoustic noise. (Cooper, No. 165 at p. 6)

DOE understands that, in certain applications, noise, and vibration, or harshness (NVH) could be especially problematic. However, based on comments, DOE does not believe that NVH concerns would be significant under the efficiency levels proposed and it does not propose to establish equipment classes using NVH as criteria for today's rule. DOE notes that several manufacturers offer technologies that reduce NVH in cases where it may be of unusual concern.

g. Multivoltage Capability

As discussed in section IIII.A, many distribution transformers have primary and secondary windings that may be reconfigured to accommodate multiple voltages. In some configurations, the transformer may operate less efficiently.

NEMA commented that DOE should exclude from further consideration transformers with multiple primary windings, because they are disadvantaged in meeting higher efficiencies. (NEMA, No. 225 at p. 6) On the other hand, Prolec-GE commented that dual voltage distribution transformers should be included and treated the same as high BIL units, and expressed concern about 7200 X 14400 volt transformers where it could be less expensive for a user to purchase the dual voltage unit than to purchase a 14400 volt single voltage unit. Further, Prolec-GE believes that this issue is limited to simpler dual voltage ratings where the ratio of the two primary voltages is exactly 2:1, and that this potential loophole was not intended under the proposed regulations. (Prolec-GE, No. 238 at p. 2)

For the reason outlined in view of this Prolec-GE comment, DOE is not establishing equipment classes by multivoltage capability in today's final rule. Nevertheless, DOE may consider doing so in future rulemakings, or consider modification of the test procedure as discussed in III.A.4, Dual/Multiple-Voltage Primary Windings.

h. Consumer Utility

A primary consideration in establishment of equipment classes is whether or not the equipment under consideration offers differential utility to the consumer. DOE sought comment on the establishment of a number of equipment classes, including pole-mounted, data-center, network/vault-based, and high BIL distribution transformers to explore whether stakeholders believed equipment utility could be affected. ABB commented that the levels proposed in the NOPR were unlikely to reduce equipment performance or utility. (ABB, No. 158 at p. 10)

Although most stakeholder discussion of space-constrained applications centered around network/vault-based distribution transformers, Howard Industries mentioned another compact application—''ranchrunners''—and requested a separate equipment class for such units (HI, No. 151 at p. 5) Based on the limited data submitted, DOE does not understand ranchrunners to be used in applications where even minimal size increases would necessarily trigger great cost increases. Furthermore, DOE does not believe large size or weight increases are likely at the standard levels under consideration. DOE may consider further consideration of the impact of increased size and weight in future rulemakings, but is not establishing separate equipment classes for ranchrunners in today's final rule.

3. Technology Options

The technology assessment provides information about existing technology options to construct more energy-efficient distribution transformers. There are two main types of losses in transformers: No-load (core) losses and load (winding) losses. Measures taken to reduce one type of loss typically increase the other type of losses. Some examples of technology options to improve efficiency include: (1) Higher-grade electrical core steels, (2) different conductor types and materials, and (3) adjustments to core and coil configurations.

In consultation with interested parties, DOE identified several technology options and designs for consideration. These technology options are presented in Table IV.2 Further detail on these technology options can be found in chapter 3 of the final rule TSD.

TABLE IV.2—OPTIONS AND IMPACTS OF INCREASING TRANSFORMER EFFICIENCY

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

* Amorphous core materials would result in higher load losses because flux density drops, requiring a larger core volume.
** Sometimes referred to as a "hexa-transformer" design.

HYDRO-Quebec (IREQ) notified DOE that a new iron-based amorphous alloy ribbon for distribution transformers was developed that has enhanced magnetic properties while remaining ductile after annealing. Further, IREQ noted that a distribution transformer assembly using this technology has been developed. (IREQ, No. 10 at pp. 1–2)

In response to the NOPR, HYDRO-Quebec offered more information on their iron-based amorphous alloy ribbon. It noted that it has two technologies to produce this amorphous ribbon: (1) A continuous in-line annealing of an amorphous ribbon moving forward at several meters per second and giving a curved shape to the ribbon that remains flexible afterwards and can easily be wound into a toroidal core with excellent soft magnetic properties, and (2) a new kernel topology for an electrical distribution transformer compromising a magnetic core made by rolling up the flexible annealed amorphous metal ribbon around the coil. (HQ, No. 125 at p. 1) Hydro-Quebec explains that production of this rolled-up-core transformer technology is automated, and the automated continuous production process makes the product cost competitive with foreign production. ''As for Hydro-Quebec's flexible ribbon, the annealing technology is compatible with implementation of compact, high-throughput, automated, and continuous production processes directly at the casting plant and would thereby benefit from the same advantages pertaining to amorphous steels.'' (HQ, No. 125 at p. 2)

DOE understands that Hydro-Quebec and others worldwide are conducting research on cost-effective manufacture of amorphous core transformers, and believes that such efforts may ultimately save energy and economically benefit consumers. At the present, however, DOE does not understand such technology to necessarily enable achievement of higher efficiency levels. Furthermore, DOE did not attempt to model such technology in its engineering analysis because it could not obtain data on what such technology costs when applied at commercial scales.

a. Core Deactivation

As noted previously, core deactivation technology employs the concept that a system of smaller transformers can replace a single, larger transformer. For example, three 25 kVA transformers operating in parallel could replace a single 75 kVA transformer.

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

In response to the NOPR, Progress Energy noted that the response time of core deactivation systems might impair power quality by increasing the transformer impedance during the initial cycles of motor starting events. (PE, No. 171 at p. 1) DOE spoke with a company that is developing a core deactivation technology. Noting that many dry-type transformers are operated at very low loadings a large percentage of the time (e.g., a building at night), the company seeks to reduce core losses by replacing a single, traditional transformer with two or more smaller units that could be activated and deactivated in response to load demands. In response to load demand changes, a special unit controls the transformers and activates and/or deactivates them in real-time.

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

In response to the NOPR, Progress Energy Carolinas, Inc. commented that core deactivation is not a proven technology and would subject utility customers to lower reliability.

DOE acknowledges that operating a core deactivation bank of transformers instead of a single unit may save energy and lower LCC for certain consumers. At present, however, DOE is adopting the position that each of the constituent transformers must comply with the energy conservation standards under the scope of the rulemaking.

b. Symmetric Core

DOE understands that several companies worldwide are commercially producing three-phase transformers with symmetric cores—those in which each leg of the transformer is identically connected to the other two. The symmetric core uses a continuously wound core with 120-degree radial symmetry, resulting in a triangularly shaped core when viewed from above. In a traditional core, the center leg is magnetically distinguishable from the other two because it has a shorter average flux path to each leg. In a symmetric core, however, no leg is magnetically distinguishable from the other two.

One manufacturer of symmetric core transformers cited several advantages to its design. These include reduced weight, volume, no-load losses, noise, vibration, stray magnetic fields, inrush current, and power in the third harmonic. Thus far, DOE has seen limited cost and efficiency data for only a few symmetric core units from testing done by manufacturers. DOE has not seen any designs for symmetric core units modeled in a software program.

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

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

DOE understands that symmetric core designs are more challenging to manufacture and require specialized equipment that is currently uncommon in the industry. However, DOE did not find a reasonable basis to screen this technology option out of the analysis, and is aware of at least one manufacturer producing dry-type symmetric core designs commercially in the United States.

For the preliminary analysis, DOE lacked the data necessary to perform a thorough engineering analysis of symmetric core designs. To generate a cost-efficiency relationship for symmetric core design transformers, DOE made several assumptions. DOE adjusted its traditional core design models to simulate the cost and efficiency of a comparable symmetric core design. To do this, DOE reduced core losses and core weight while increasing labor costs to approximate the symmetric core designs. These adjustments were based on data received from manufacturers, published literature, and through conversations with manufacturers. Table IV.3 indicates the range of potential adjustments for each variable that DOE considered and the mean value used in the analysis.

TABLE IV.3—SYMMETRIC CORE DESIGN ADJUSTMENTS

Range	[Percentage changes]		
	Core losses *W*	Core weight *lb*	Labor hours
.			
Minimum	−0.0	−12.0	+10.0
Mean	−15.5	−17.5	+55.0
Maximum	−25.0	−25.0	+100.0

DOE applied the adjustments to each of the traditional three-phase transformer designs to develop a cost-efficiency relationship for symmetric core technology. DOE did not model a tertiary winding for the wye-wye connected liquid-immersed design lines (DLs). Based on its research, DOE believes that the losses associated with the tertiary winding may offset the benefits of the symmetric core design and that the tertiary winding will add cost to the design. Therefore, DOE modeled symmetric core designs for the three-phase liquid-immersed design lines without a tertiary winding to examine the impact of symmetric core technology on the subgroup of applications that do not require the tertiary winding.

DOE attempts to consider all designs that are technologically feasible and practicable to manufacture and believes that symmetric core designs can meet these criteria. However, DOE was not able to obtain or produce sufficient data to modify its analysis of symmetric cores after the preliminary analysis. For this reason, DOE did not consider symmetric core designs as part of the NOPR analysis.

In response to the NOPR, several manufacturers expressed support for excluding symmetric core designs from DOE's analysis. ComEd, EEI, Progress Energy, NRECA, and APPA all commented that they were pleased to see symmetric core designs excluded from the NOPR analysis. (ComEd, No. 184 at p. 11; EEI, No. 185 at p. 9; APPA, No. 191 at p. 9; PE, No. 192 at p. 7; NRECA, No. 172 at p. 7) BG&E recommended that symmetric core designs not be included in the final rule based on previous comments that highlighted significant issues with the proposed designs. (BG&E, No. 182 at p. 5) Cooper Power pointed out that symmetric core designs have not proven themselves in the market place, and therefore should be excluded in terms of their technological feasibility. (Cooper, No. 165 at p. 4) Similarly, Prolec-GE saw many issues with the use of symmetric core in medium-voltage liquid-filled transformers, and did not believe that this technology offered benefits. (Prolec-GE, No. 177 at p. 10)

ABB and NEMA both observed that any information regarding symmetric core technology for distribution transformers is currently considered strategic and proprietary and cannot be entered into the public record at this time. (ABB, No. 158 at p. 7) NEMA argued further that while it is important for DOE to understand the potential of emerging technologies, such technologies should not be introduced into the regulation until they have proven themselves in the marketplace; symmetric core designs are currently of low penetration in the industry and have not been proven to offer potential for efficiency improvement. (NEMA, No. 170 at p. 11)

Howard Industries commented that symmetric core technology is not appropriate for the majority of the U.S. distribution transformer market, noting that this style of design results in much deeper tanks and larger pads as well as a new winding configuration. It also pointed out that symmetric core designs are patented by Hexaformer AB, in Sweden, and manufacturing this technology requires a license from Hexaformer. Overall, they feel that the cost to adapt to this technology would be large, impractical, and time consuming. (HI, No. 151 at p. 12) Progress Energy Carolinas, Inc. concurred with Howard Industries that the winding configuration for symmetric core designs would be problematic. They pointed out that the delta tertiary winding needed will be subject to thermal failure, and increase the losses of the transformer. Furthermore, they pointed out that the presence of a delta tertiary winding on a wye-wye three-phase distribution transformer will provide a source for zero-sequence currents to ground faults on the source distribution system, resulting in backfeed and, consequently, a potentially hazardous situation. (PE, No. 171 at p. 1)

Finally, Schneider Electric asserted that the efficiency levels proposed in the NOPR are not high enough to lead manufacturers to evaluate symmetric core technology. It commented that, to fully explore these and other technologies, the implementation time and efficiency levels must be increased. It was Schneider Electric's opinion that further, increasing the levels in small increments and only giving four years to transition does not allow for proper research and development to be completed to properly comment on any new technology. (Schneider, No. 180 at p. 5)

In response to the NOPR, DOE did not receive any data that would force reconsideration of the symmetric core analysis conducted during the preliminary analysis. Stakeholders expressed support for the exclusion of this technology from the NOPR analysis. For all of the above reasons, DOE does not consider symmetric core designs as part of the final rule analysis.

c. Intellectual Property

In setting standards, DOE seeks to analyze the efficiency potentials of commercially available technologies and working prototypes, as well as the availability of those technologies to the market at-large. If certain market participants own intellectual property that enables them to reach efficiencies that other participants practically cannot, amended standards may reduce the competitiveness of the market.

In the case of distribution transformers, stakeholders have raised potential intellectual property concerns surrounding both symmetric core technology and amorphous metals in particular. DOE currently understands that symmetric core technology itself is not proprietary, but that one of the more commonly employed methods of production is the property of the Swedish company Hexaformer AB. However, Hexaformer AB's method is not the only one capable of producing symmetric cores. Moreover, Hexaformer AB and other companies owning intellectual property related to the manufacture of symmetric core designs have demonstrated an eagerness to license such technology to others that are using it to build symmetric core transformers commercially today.

DOE understands that symmetric core technology may ultimately offer a lower-cost path to higher efficiency, at least in certain applications, and that few symmetric cores are produced in the United States. However, DOE notes again that it has been unable to secure data that are sufficiently robust for use as the basis for an energy conservation standard, but encourages interested parties to submit data that would assist in DOE's analysis of symmetric core technology in future rulemakings.

d. Core Construction Technique

DOE examines a number of core construction techniques in its engineering analysis, including butt-lapping, full mitering, step-lap mitering, and distributed gap wound construction. Particularly in the low-voltage dry-type market, where some smaller manufacturers may not own large mitering machines, core construction methodology is of concern. In the NOPR, DOE did not examine butt-lapped core construction as a design option for design line 7 for steel grades above M6 and, as a result, found only butt-lapped designs are feasible through EL 2. Since the NOPR, however, DOE has reassessed the assumption that butt-lapping is not possible beyond EL 2. For design lines 6 and 8, the topic of butt-lapping is less consequential. All of DOE's design line 6 analysis is centered around butt-lapping,[27] while the use of mitering for larger LVDT units (represented by design line 8) is prevalent in both the market and DOE's analysis.

DOE received several comments on core construction method as it relates to design line 7. During the negotiated rulemaking, ASAP commented that DOE should further explore whether butt-lapping was possible beyond EL 2. (ASAP, No. 146 at p. 135, pp. 25–26) HVOLT, a power and distribution transformer consulting company, commented that butt-lapping could probably get very close to EL 3, but not be the most cost competitive choice at that level. (HVOLT, No. 146 at p. 135) ASAP also commented that DOE should explore more design options in the interest of creating a smoother curve, and that butt-lapped options should be among them. (ASAP, No. 146 at pp. 24–25)

In response to the NOPR, ASAP, two manufacturers of LVDTs, and California Investor-Owned Utilities urged DOE to reconsider the technological assumptions (including butt-lapping capabilities at higher TSLs) behind its TSL 1 proposal. ASAP stated that it believed a more careful consideration of the record and a more thorough investigation of the impacts on small, domestic manufacturers would lead DOE to TSL 3, noting that many manufacturers supported at least TSL 2 during the negotiated rulemaking and believed that TSL 2 could be attained using butt-lapping. (ASAP, No. 186 at pp. 3, 7–8) Eaton generally recommended that DOE standardize efficiency levels to EL 3 (i.e., NEMA Premium®), stating that such efficiency levels are realistic using current technology and are very close to the standards DOE proposed in the NOPR. (Eaton, No. 157 at p. 2) The California IOUs commented that DOE should revise its analysis to reflect that core construction techniques are currently used to produce efficiencies higher than TSL 1 for both small and large manufacturers. (CA IOUs, No. 189 at p. 2) The group of utilities also stated that NEMA lists 11 manufacturers committed to delivering LVDTs at NEMA Premium® efficiency levels, including both large and small manufacturers. (CA IOUs, No. 189 at p. 2) Schneider Electric reiterated its support of efficiency levels higher than those proposed in the NOPR. (Schneider, No. 180 at p. 1)

DOE understands that the ability to produce transformers using a variety of construction techniques is important to preserving design flexibility. After receiving the above-referenced comments on the NOPR, DOE consulted with technical design experts and learned that butt-lapping is technologically feasible for DL 7 through EL 3. DOE revises its understanding of the limits of butt-lapped core construction in today's rule to extend through EL 3 in DL 7.

B. Screening Analysis

DOE uses the following four screening criteria to determine which design options are suitable for further consideration in a standards rulemaking:

1. *Technological feasibility.* Technologies incorporated in commercial products or in working prototypes will be considered to be technologically feasible.

2. *Practicability to manufacture, install, and service.* If mass production of a technology in commercial products and reliable installation and servicing of the technology could be achieved on the scale necessary to serve the relevant market at the time of the effective date of the standards, then that technology will be considered practicable to manufacture, install, and service.

3. *Impacts on product utility to consumers.* 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 United States at the time, it will not be considered further.

4. *Safety of technologies.* If it is determined that a technology will have significant adverse impacts on health or safety, it will not be considered further. (10 CFR part 430, subpart C, appendix A)

In the preliminary analysis, DOE identified the technologies for improving distribution transformer efficiency that were under consideration. DOE developed this initial list of design options from the technologies identified in the technology assessment. Then DOE reviewed the list to determine if the

[27] Except for the amorphous design options, because DOE eliminates consideration of amorphous cores in butt-lapped and other stacked configurations in its screening analysis.

design options are practicable to manufacture, install, and service; would adversely affect equipment utility or equipment availability; or would have adverse impacts on health and safety. In the engineering analysis, DOE only considered those design options that satisfied the four screening criteria. The design options that DOE did not consider because they were screened out are summarized in Table IV.4.

TABLE IV.4—DESIGN OPTIONS SCREENED OUT OF THE ANALYSIS

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

Chapter 4 of the TSD discusses each of these screened-out design options in more detail. The chapter also includes a list of emerging technologies that could impact future distribution transformer manufacturing costs.

1. Nanotechnology Composites

DOE is aware that materials science research is being conducted into the use of nanoscale engineering to improve certain properties of materials used in transformers. Nanotechnology is the manipulation of matter on an atomic and molecular scale. Such materials have small-scale structures created through novel manufacturing techniques that may give rise to improved properties (e.g., higher resistivity in steel) not natively present in the bulk material. At present, DOE has not learned of any such materials that meet DOE's criteria of being practicable to manufacture and does not consider nanotechnology composites in its engineering analysis.

Many stakeholders were supportive of DOE's decision to exclude nanotechnology from their analysis in the NOPR. Howard Industries and Cooper Power both expressed that nanotechnology is not a proven technology in the field of distribution transformers; nanotechnology is still in the research phase and further development would be required prior to being viable in the distribution transformer field. (HI, No. 151 at p. 12; Cooper, No. 165 at p. 4) Prolec-GE agreed, pointing out that this technology is ''still in its infancy and there is not enough public information to make a practicable analysis if benefits exist.'' (Prolec-GE, No. 177 at p. 11) While NRECA, EEI and APPA all expressed interest in the development of advanced technologies that could result in more efficient transformers, they agree with the above stakeholders that this technology is not currently available for distribution transformers. (NRECA, No. 172 at p. 7; APPA, no. 191 at p. 9; EEI, No. 185 at p. 9; BG&E, No. 182 at p. 5) ComEd and Progress Energy noted that, due to lack of availability, nanotechnology composites should not be included in DOE's final rule. (ComEd, No. 184 at p. 11; PE, No. 192 at p. 7)

Stakeholders also noted that information on nanotechnology is not currently readily available. ABB pointed out that any information regarding the application and design of nanotechnology in distribution transformers is considered strategic and proprietary and that these composites are not currently commercially available in the distribution transformer market. (ABB, No. 158 at p. 7) NEMA agreed, stating, ''this technology is in its infancy. Information regarding an individual manufacturer's application of this technology is considered strategic and proprietary and cannot be divulged in the public record at this time.'' (NEMA, No. 170 at p. 11)

DOE understands that the nanotechnology field is actively researching ways to produce bulk material with desirable features on a molecular scale. Some of these materials may have high resistivity, high permeability, or other properties that make them attractive for use in electrical transformers. DOE knows of no current commercial efforts to employ these materials in distribution transformers and no prototype designs using this technology. Therefore, DOE does not consider nanotechnology composites in the today's rulemaking.

C. Engineering Analysis

The engineering analysis develops cost-efficiency relationships for the equipment that are the subject of a rulemaking by estimating manufacturer costs of achieving increased efficiency levels. DOE uses manufacturing costs to determine retail prices for use in the LCC analysis and MIA. In general, the engineering analysis estimates the efficiency improvement potential of individual design options or combinations of design options that pass the four criteria in the screening analysis. The engineering analysis also determines the maximum technologically feasible (''max-tech'') energy efficiency level.

DOE must consider those distribution transformers that are designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy determines to be technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) Therefore, an important role of the engineering analysis is to identify the maximum technologically feasible efficiency level. The maximum technologically feasible level is one that can be reached by adding efficiency improvements and/or design options, both commercially feasible and in prototypes, to the baseline units. DOE believes that the design options comprising the maximum technologically feasible level must have been physically demonstrated in a prototype form to be considered technologically feasible.

In general, DOE can use three methodologies to generate the manufacturing costs needed for the engineering analysis. These methods are:

(1) The design-option approach—reporting the incremental costs of adding design options to a baseline model;

(2) the efficiency-level approach—reporting relative costs of achieving improvements in energy efficiency; and

(3) the reverse engineering or cost assessment approach—involving a ''bottom up'' manufacturing cost

assessment based on a detailed bill of materials derived from transformer teardowns.

DOE's analysis for this rulemaking is based on the design-option approach, in which design software is used to assess the cost-efficiency relationship between various design option combinations. This is the same approach that was taken in the 2007 final rule for distribution transformers.

1. Engineering Analysis Methodology

When developing its engineering analysis for distribution transformers, DOE divided the covered equipment into equipment classes. As discussed, distribution transformers are classified by insulation type (liquid immersed or dry type), number of phases (single or three), primary voltage (low voltage or medium voltage for dry-type distribution transformers) and basic impulse insulation level (BIL) rating (for dry types). Using these transformer design characteristics, DOE developed ten equipment classes. Within each of these equipment classes, DOE further classified distribution transformers by their kilovolt-ampere (kVA) rating. These kVA ratings are essentially size categories, indicating the power handling capacity of the transformers. For DOE's rulemaking, there are over 100 kVA ratings across all ten equipment classes.

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

After developing its DLs, DOE then selected one representative unit from each DL for study, greatly reducing the number of units for direct analysis. For each representative unit, DOE generated hundreds of unique designs by contracting with Optimized Program Services, Inc. (OPS), a software company specializing in transformer design since 1969. The OPS software used three primary inputs that it received from DOE: (1) A design option combination, which included core steel grade, primary and secondary conductor material, and core configuration; (2) a loss valuation combination; and (3) material prices. For each representative unit, DOE examined anywhere from 8 to 16 design option combinations and for each design option combination, the OPS software generated 518 designs based on unique loss valuation combinations. These loss valuation combinations are known in industry as A and B evaluation combinations and represent a customer's present value of future losses in a transformer core and winding, respectively. For each design option combination and A and B combination, the OPS software generated an optimized transformer design based on the material prices that were also part of the inputs. Consequently, DOE obtained thousands of transformer designs for each representative unit. The performance of these designs ranged in efficiency from a baseline level, equivalent to the current distribution transformer energy conservation standards, to a theoretical max-tech efficiency level.

After generating each design, DOE used the outputs of the OPS software to help create a manufacturer selling price (MSP). The material cost outputs of the OPS software, along with labor estimates, were marked up for scrap factors, factory overhead, shipping, and non-production costs to generate a MSP for each design. Thus, DOE obtained a cost versus efficiency relationship for each representative unit. Finally, after DOE had generated the MSPs versus efficiency relationship for each representative unit, it extrapolated the results to the other, unanalyzed, kVA ratings within that same engineering design line.

PEMCO commented that DOE generated too many designs, and that many were impractical or unlikely to sell. (PEMCO, No. 183 at p. 1) EMS Consulting made an opposite remark, that DOE's chosen methodology omits many possible solutions. (EMS, No. 178 at p. 5) Finally, NEMA commented that the ''steepness'' of some of DOE's curves were lower than was shown by some manufacturers, ABB in particular. (NEMA, No. 170 at p. 4, p. 3) In other words, NEMA questioned whether cost might rise more quickly with efficiency than DOE's analysis suggested. Conversely, ATI Allegheny commented that DOE did excellent work on the engineering analysis. (ATI, No. 181 at p. 1)

DOE acknowledges both that it may not have analyzed every possible design and that, conversely, some designs would be unlikely to be considered by many purchasers, but notes that the goal of the engineering analysis is to both explore the limits of design possibility and establish a cost/efficiency behavior. The Life-Cycle Cost and Payback Period Analysis, in turn, examines which of the designs would be cost-effective for individual purchasers. It would not be practical to attempt to analyze every possible physical design. Regarding NEMA's comments, DOE is always seeking constructive feedback to aid in the accuracy of its engineering analysis, but cautions that comparisons between designs must be made carefully in order to be sure that they remain valid across a wide variety of market forces and construction techniques. A manufacturer's cost of producing higher-efficiency units in today's market may be different than the cost of meeting those same efficiencies after establishment of energy conservation standards, which may lead to production at higher volumes.

2. Representative Units

For the preliminary analysis, DOE analyzed 13 DLs that cover the range of equipment classes within the distribution transformer market. Within each DL, DOE selected a representative unit to analyze in the engineering analysis. A representative unit is meant to be an idealized unit typical of those used in high volume applications.

In view of comments received from stakeholders throughout the analysis period, DOE slightly modified its representative units for the NOPR analysis. For the NOPR, DOE analyzed the same 13 representative units as in the preliminary analysis, but also added a design line, and therefore representative unit, by splitting the former design line 13 into two new design lines, 13A and 13B. This new representative unit allows DOE's analysis to better reflect the behavior of high kVA, high BIL medium-voltage dry-type units and is shown in Table IV.5. The representative units selected by DOE were chosen because they comprise high volume segments of the market for their respective design lines and also provide, in DOE's view, a reasonable basis for scaling to the unanalyzed kVA ratings. DOE chooses certain designs to analyze as representative of a particular design line or design lines because it is impractical to analyze all possible designs in the scope of coverage for this rulemaking.

DOE also notes that as a part of the negotiations process, DOE worked directly with multiple interested parties to develop a new scaling methodology for the NOPR that addresses some of the interested party concerns regarding scaling.

TABLE IV.5—ENGINEERING DESIGN LINES (DLS) AND REPRESENTATIVE UNITS FOR NOPR ANALYSIS

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

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

3. Design Option Combinations

There are many different combinations of design options that could be considered for each representative unit DOE analyzes. While DOE cannot consider all the possible combinations of design options, DOE attempts to select design option combinations that are common in the industry while also spanning the range of possible efficiencies for a given DL. For each design option combination chosen, DOE evaluates 518 designs based on different A and B factor [28] combinations. For the engineering analysis, DOE reused many of the design option combinations that were analyzed in the 2007 final rule for distribution transformers. 72 FR 58190 (October 12, 2007).

For the preliminary analysis, DOE considered a design option combination that uses an amorphous steel core for each of the dry-type design lines, whereas DOE's 2007 final rule did not consider amorphous steel designs for the dry-type design lines. Instead, DOE had considered H–0 domain refined (H–0 DR) steel as the maximum-technologically feasible design. However, DOE is aware that amorphous steel designs are now used in dry-type distribution transformers. Therefore, DOE considered amorphous steel designs for each of the dry-type transformer design lines in the preliminary analysis.

During preliminary interviews with manufacturers, DOE received comment that it should consider additional design option combinations using aluminum for the primary conductor rather than copper. While manufacturers commented that copper is still used for the primary conductor in many distribution transformers, they noted that aluminum has become relatively more common. This is due to the relative prices of copper and aluminum. In recent years, copper has become even more expensive compared to aluminum.

DOE also noted that certain design lines were lacking a design to bridge the efficiency values between the lowest efficiency amorphous designs and the next highest efficiency designs. In an effort to close that gap for the preliminary analysis, DOE evaluated ZDMH and M2 core steel as the highest efficiency designs below amorphous for the liquid-immersed design lines. Similarly, DOE evaluated H–0 DR and M3 core steel as the highest efficiency designs below amorphous for dry-type design lines.

DOE incorporated these supplementary designs into the reference case (i.e., DOE's default set of assumptions without any sensitivity analysis) for the NOPR analysis. Additionally, DOE aimed to consider the most popular design option combinations, and the design option combinations that yield the greatest improvements in efficiency. While DOE was unable to consider all potential design option combinations, it did consider multiple designs for each representative unit and considered additional design options in its NOPR analysis based on stakeholder comments.

As for wound core designs, DOE did consider analyzing them for all of its dry-type representative units that are

[28] A and B factors correspond to loss valuation and are used by DOE to generate distribution transformers with a broad range of performance and design characteristics.

300 kVA or less in the NOPR. However, based on limited availability in the United States, DOE did not believe that it was feasible to include these designs in their final engineering results. For similar availability reasons, DOE chose to exclude its wound core ZDMH and M3 designs from its low-voltage dry-type analysis. Based on how uncommon these designs are in the current market, DOE believes that it would be unrealistic to include them in engineering curves without major adjustments.

DOE did not consider wound core designs for DLs 10, 12, and 13B because they are 1500 kVA and larger. DOE understands that conventional wound core designs in these large kVA ratings will emit an audible ''buzzing'' noise, and will experience an efficiency penalty that grows with kVA rating such that stacked core is more attractive. DOE notes, however, that it does consider a wound core amorphous design in each of the dry-type design lines.

DOE did opt to add two design option combinations that incorporate M-grade steels that have become popular choices at the current standard levels. For all medium-voltage dry-type design lines (9–13B), DOE added a design option combination of an M4 step-lap mitered core with aluminum primary and secondary windings. For design line 8, DOE added a design option combination of an M6 fully mitered core with aluminum primary and secondary windings. DOE understands both combinations to be prevalent baseline options in the present transformer market.

For the NOPR analysis, DOE also made the decision to remove certain high flux density designs from DL7 to be consistent with designs submitted by manufacturers.[29] There is a variety of reasons that manufacturers would choose to limit flux density (e.g., vibration, noise). Further detail on this change can be found in chapter 5 of the TSD. The design remains that way for today's final rule.

In response to the NOPR, Eaton noted that this rule provides many design options, and allows for the use of various designs and different grades of steel, but encouraged DOE to standardize the efficiency levels to NEMA Premium® (i.e., EL 3). (Eaton, No. 157 at p. 2) Although Schneider supported the LVDT efficiency levels proposed by DOE in the NOPR, the company stated in its NOPR comments that it still supports efficiency levels higher than those proposed in the NOPR (as evidenced by discussions during the negotiated rulemaking meetings.) (Schneider, No. 180 at p. 1)

ASAP commented that it perceived there to be a ''gap'' in the DL 7 data, and that DOE should seek to fill that gap by exploring other design option combinations corresponding to butt-lapped core construction. (ASAP, No. 146 at p. 24–25, 135) In response, DOE first generated analysis for two additional design option combinations: An M4 core with aluminum windings and an M3 core with copper windings. DOE includes both sets of results in its final rule engineering analysis. In general, DOE notes that preservation of a number of design options was a strong consideration in selection of the final standard. Second, given these two new design lines discussed above, DOE revisited the question of whether DL 7 for LVDTs was achievable by manufacturers with butt lapping techniques in order to avoid purchasing mitering equipment. Specifically, DOE consulted with technical design experts, and they confirmed butt-lapping was technically feasible through EL 3. In addition, as detailed in section IV.A.3, DOE received public comment supporting this conclusion and did not receive public comments directly refuting this conclusion. (See, e.g., ASAP, No. 186 at pp. 3, 7–8; Eaton, No. 157 at p. 2; CA IOUs, No. 189 at p. 2)

Consequently, DOE modified the LVDT standard proposed from TSL 1 to TSL 2 in today's final rule.

DL 7 analysis illustrating the possibility of constructing butt-lapped cores at EL3 led DOE to reconsider the impacts to small manufacturers. DOE originally assumed that a small manufacturer without the equipment needed to construct mitered cores would have to either invest in such equipment at considerable expense, source cores from a third party, or exit that market. As explained in Section IV.I.1, DOE calculates the net present value of the industry (''INPV'') in attempting to quantify impacts to manufacturers under different scenarios. During the NOPR, DOE calculated LVDT INPV to be between $200 million and $235 million (in 2011$). In today's final rule, that figure rises to $227 million to $249 million (in 2011$).

In addition, as described in the NOPR and as DOE confirmed for the final rule, DOE understands that the majority of the LVDT market volume is currently imported, much of it from large, well-capitalized manufacturers in Mexico. Furthermore, many small businesses operating inside the United States cater to niches outside of DOE's scope of coverage, and would not be directly affected by the rule. Finally, DOE spoke with several small domestic manufacturers and learned that some are already able to miter cores, and would make the decision to butt-lap or miter at EL3 based on economics and without facing large capital investment decisions. More detail can be found in Section IV.I.5.b.

4. A and B Loss Value Inputs

As discussed, one of the primary inputs to the OPS software is an A and B combination for customer loss evaluation. In the preliminary analysis, DOE generated each transformer design in the engineering analysis based upon an optimized lowest total owning cost evaluation for a given combination of A and B values. Again, the A and B values represent the present value of future core and coil losses, respectively and DOE generated designs for over 500 different A and B value combinations for each of the design option combinations considered in the analysis.

DOE notes that the designs created in the engineering analysis span a range of costs and efficiencies for each design option combination considered in the analysis. This range of costs and efficiencies is determined by the range of A and B factors used to generate the designs. Although DOE does not generate a design for every possible A and B combination, because there are infinite variations, DOE believes that its 500-plus combinations have created a sufficiently broad design space. By using so many A and B factors, DOE is confident that it produces the lowest first cost design for a given efficiency level and also the lowest total owning cost design. Furthermore, although all distribution transformer customers do not purchase based on total owning cost, the A and B combination is still a useful tool that allows DOE to generate a large number of designs across a broad range of efficiencies and costs for a particular design line. Finally, OPS noted at the public meeting that its design software requires A and B values as inputs. (OPS, Pub. Mtg. Tr., No. 34 at p. 123) For all of these reasons, DOE continued to use A and B factors from the NOPR to generate the range of designs for the final rule engineering analysis.

5. Materials Prices

In distribution transformers, the primary materials costs come from electrical steel used for the core and the aluminum or copper conductor used for

[29] During the negotiations process, DOE's subcontractor, Navigant Consulting, Inc. (Navigant), participated in a bidirectional exchange of engineering data with industry representatives in an effort to validate the OPS designs generated for the engineering analysis.

the primary and secondary winding. As these are commodities whose prices frequently fluctuate throughout a year and over time, DOE attempted to account for these fluctuations by examining prices over multiple years. For the preliminary analysis, DOE conducted the engineering analysis analyzing materials price information over a five-year time period from 2006–2010, all in constant 2010$. Whereas DOE used a five-year average price in the 2007 final rule for distribution transformers, for the preliminary analysis in this rulemaking, DOE selected one year from its five-year time frame as its reference case, namely 2010. Additionally, DOE considered high and low materials price sensitivities from that same five-year time frame, 2008 and 2006 respectively.

DOE decided to use current (2010) materials prices in its analysis for the preliminary analysis because of feedback from manufacturers during interviews. Manufacturers noted the difficulty in choosing a price that accurately projects future materials prices due to the recent variability in these prices. Manufacturers also commented that the previous five years had seen steep increases in materials prices through 2008, after which prices declined as a result of the global economic recession. Further detail on these factors can be found in appendix 3A. Due to the variability in materials prices over this five-year timeframe, manufacturers did not believe a five-year average price would be the best indicator, and recommended using the current materials prices.

To estimate its materials prices, DOE spoke with manufacturers, suppliers, and industry experts to determine the prices paid for each raw material used in a distribution transformer in each of the five years between 2006 and 2010. While prices fluctuate during the year and can vary from manufacturer to manufacturer depending on a number of variables, such as the purchase quantity, DOE attempted to develop an average materials price for the year based on the price a medium to large manufacturer would pay.

With the onset of the negotiations, DOE was presented with an opportunity to implement a 2011 materials price case based on data it had gathered before and during the negotiation proceedings. Relative to the 2010 case, the 2011 prices were lower for all steels, particularly M2 and lower grade steels.

For the NOPR, DOE reviewed its materials prices during interviews with manufacturers and industry experts and revised its materials prices for copper and aluminum conductors. DOE derived these prices by adding a processing cost increment to the underlying index price. DOE determined the current 2011 index price from the LME and COMEX, two well-known commodities benchmarks. These indices only had current 2011 values available, so DOE used the producer price index for copper and aluminum to convert the 2011 index price into prices for the time period of 2006–2010. DOE then applied a unique processing cost adder to the index price for each of its conductor groupings. To derive the adder price, DOE compared the difference in the LME index price to the 2011 price paid by manufacturers, and applied this difference to the index price in each year. DOE inquired with many manufacturers, both large and small, to derive these prices. Materials price cases for the final rule are identical to those of the NOPR. Further detail can be found in chapter 5 of the TSD.

DOE reviewed core steel prices with manufacturers and industry experts and found them to be accurate within the range of prices paid by manufacturers in 2010. However, based on feedback in negotiations, DOE adjusted steel prices for M4 grade steels and lower grade steels.

Several stakeholders commented on the material prices used in the NOPR. ABB, NRECA, and NEMA all noted that the material costs appeared to be too low, both for 2010 and 2011. (ABB, No. 158 at pp. 7–8; NEMA, No. 170 at p. 11; NRECA, No. 146 at p. 159) Similarly, Prolec-GE pointed out that, as the economy recovers, demand for these materials will increase, as will their prices. They agreed that DOE's material price projections were too low. (Prolec-GE, No. 177 at p. 11) ATI specifically noted that DOE's price for M3 steel was too low in the 2011 price scenario, and commented that this price is a very important one in the analysis. (ATI, No. 146 at pp. 74–75) Progress Energy concurred, noting that the price of silicon core steel in DOE's analysis was lower than actual prices, and recommended that DOE revise all their material prices. (PE, No. 192 at p. 7) Cooper and HI agreed with these stakeholders that DOE's material prices were too low, specifically pointing out that surcharges need to be included to more accurately reflect real world prices. (Cooper, No. 165 at p. 4; HI, No. 151 at p. 12)

APPA did not disagree with DOE's material prices, but pointed out that if DOE choose to update them, they should update wholesale electric prices to the most recent year available as well. (APPA, No. 191 at p. 9) BG&E and ComEd agreed, pointing out ''base costs, for both material and wholesale energy, should reflect from the most recent published data for the most recent year.'' (BG&E No. 182 at p. 5; ComEd, No. 184 at p. 11) ASAP commented that DOE should re-optimize its engineering analysis with respect to the new pricing to find the most accurate results. (ASAP, No. 146 at p. 153)

DOE notes that because it analyzes such a large breadth of designs, its engineering analysis is less sensitive to changes in materials prices than it otherwise would be. DOE performed a sensitivity analysis during the preliminary analysis phase of the rulemaking in order to understand the magnitude of the effect of a change in material prices and found it to be very small. The differential pricing between the designs, upon which the LCC, NIA, and other economics results are based, are even less sensitive. DOE believes its conclusions would not vary between either case.

DOE appreciates the above-listed feedback from commenters, however, for today's rule, DOE continues to use the 2010 and 2011 materials prices that were first included in the NOPR as reference case scenarios, which is the most recent and accurate information available to DOE. DOE presents both cases as recent examples of how the steel market fluctuates and uses both to derive economic results. It also considered high and low price scenarios based on the 2008 and 2006 materials prices, respectively, but adjusted the prices in each of these years to consider greater diversity in materials prices. For the high price scenario, DOE increased the 2008 prices by 25 percent, and for the low price scenario, DOE decreased the 2006 prices by 25 percent as additional sensitivity analyses. DOE believes that these price sensitivities accurately account for any pricing discrepancies experienced by smaller or larger manufacturers, and adequately consider potential price fluctuations.

For the engineering analysis, DOE did not attempt to forecast future materials prices. DOE continued to use the 2010 materials price in the reference case scenario, added a 2011 reference scenario, and also considered high and low sensitivities to account for any potential fluctuations in materials prices. The LCC and NIA consider a scenario, however, in which transformer prices increase in the future based on increasing materials prices, among other variables. Further detail on this scenario can be found in chapter 8 of the TSD.

6. Markups

DOE derived the manufacturer's selling price for each design in the engineering analysis by considering the full range of production costs and non-production costs. The full production cost is a combination of direct labor, direct materials, and overhead. The overhead contributing to full production cost includes indirect labor, indirect material, maintenance, depreciation, taxes, and insurance related to company assets. Non-production cost includes the cost of selling, general and administrative items (market research, advertising, sales representatives, and logistics), research and development (R&D), interest payments, warranty and risk provisions, shipping, and profit factor. Because profit factor is included in the non-production cost, the sum of production and non-production costs is an estimate of the manufacturer's selling price. DOE utilized various markups to arrive at the total cost for each component of the distribution transformer. These markups are outlined in greater detail in chapter 5 of the TSD.

DOE interviewed manufacturers of distribution transformers and related products to learn about markups, among other topics, and observed a number of very different practices. In absence of a consensus, DOE attempted to adapt manufacturer feedback to inform its current modeling methodology while acknowledging that it may not reflect the exact methodology of many manufacturers. DOE feels that it is necessary to model markups, however, since there are costs other than material and labor that affect final manufacturer selling price. The following sections describe various facets of DOE's markups for distribution transformers.

a. Factory Overhead

DOE uses a factory overhead markup to account for all indirect costs associated with production, indirect materials and energy use (e.g., annealing furnaces), taxes, and insurance. In the preliminary analysis, DOE derived the cost for factory overhead by applying a 12.5 percent markup to direct material production costs.

In the preliminary analysis, DOE applied the same factory overhead markup to its prefabricated amorphous cores as it did to its other design options where the manufacturer was assumed to produce the core. Since the factory overhead markup accounts for indirect production costs that are not easily tied to a particular design, it was applied consistently across all design types. DOE did not find that there was sufficient substantiation to conclude that manufacturers would apply a reduced overhead markup for a design with a prefabricated core.

For today's rule, DOE continued to apply the same factory overhead markup to prefabricated amorphous cores as to other cores built in-house. This approach is consistent with the suggestion of the manufacturers, and DOE notes that factory overhead for a given design applies to many items aside from the core production. Furthermore, since DOE already accounts for decreased labor hours in its designs using prefabricated amorphous cores, but also considers an increased core price based on a prefabricated core rather than the raw amorphous material, it already accounts for the tradeoffs associated with developing the core in-house versus out-sourced.

During negotiations, DOE learned from both manufacturers of transformers and manufacturers of transformer cores that mitering and, to a greater extent, step-lap mitering result in a per-pound cost of finished cores higher than the per-pound cost of butt-lapped units built to the same specifications. (ONYX, Pub. Mtg. Tr., No. 30 at p. 43) In view of the manufacturer comments, DOE understands that butt-lapping is common at baseline efficiencies in today's low-voltage market.

In response, DOE opted to increase mitering costs for both low- and medium-voltage dry-type designs. In the medium-voltage case, DOE incorporated a processing cost of 10 cents per core pound for step-lap mitering. In the low-voltage case, DOE incorporated a processing cost of 10 cents per core pound for ordinary mitering and 20 cents per core pound for step-lap mitering. DOE used different per pound adders for step-lap mitering for medium-voltage and low-voltage units because the base case design option for each is different. For low-voltage units, DOE modeled butt-lapped designs at the baseline efficiency level whereas ordinary mitering was modeled at the baseline for medium-voltage. Therefore, using a step-lap mitered core represents a more significant change in technology for low-voltage dry-type transformers than for medium-voltage transformers, necessitating higher markup.

b. Labor Costs

In the preliminary analysis, DOE accounted for additional labor and material costs for large (≥1500 kVA), dry-type designs using amorphous metal. The additional labor costs accounted for special handling considerations, since the amorphous material is very thin and can be difficult to work with in such a large core. They also accounted for extra bracing that is necessary for large, wound core, dry-type designs in order to prevent short circuit problems.

In response to interested party feedback, DOE applied an incremental increase in core assembly time to amorphous designs in the liquid-immersed design line 5 (1500 kVA). This additional core assembly time of 10 hours is consistent with DOE's treatment of amorphous designs in large, dry-type design lines. However, DOE did not account for additional hardware costs for bracing in the liquid-immersed designs using amorphous cores. This is because DOE already accounts for bracing costs for all of its liquid-immersed designs, which use wound cores, in its analysis. DOE determined that it adequately accounted for these bracing costs in the smaller kVA sizes using amorphous designs, and thus only made the change to the large (≥1500 kVA) design lines. DOE did not model varying incremental cost increases starting with zero for large amorphous designs, as the Northwest Energy Efficiency Alliance (NEEA) and Northwest Power and Conservation Council (NPCC) suggested, noting that the impact of these incremental costs are often very minor for large, expensive transformer designs. (NEEA, No. 11 at p. 7) Following discussion with Federal Pacific and other manufacturers of medium- and low-voltage transformers, DOE explored its estimates of labor hours and increased those relating to core assembly for design lines 6–13B. Details on the specific values of the adjustments can be found in chapter 5 of the TSD.

c. Shipping Costs

During its interviews with manufacturers in the preliminary analysis, DOE was informed that manufacturers often pay shipping (freight) costs to the customer. Manufacturers indicated that they absorb the cost of shipping the units to the customer and that they include these costs in their total cost structure when calculating profit markups. As such, manufacturers apply a profit markup to their shipping costs just like any other cost of their production process. Manufacturers indicated that these costs typically amount to anywhere from four to eight percent of revenue.

In the 2007 final rule, DOE accounted for shipping costs exclusively in the LCC analysis. These costs were paid by the customer, and thus did not include a markup from the manufacturer based on its profit factor. In the preliminary analysis, DOE included shipping costs in the manufacturer's cost structure, which is then marked up by a profit factor. These shipping costs account for delivering the units to the customer, who may then bear additional shipping costs to deliver the units to the final end-use location. As such, DOE accounts for the first leg of shipping costs in the engineering analysis and then any subsequent shipping costs in the LCC analysis. The shipping cost was estimated to be $0.22 per pound of the transformer's total weight. DOE derived the $0.22 per pound by relying on the shipping costs developed in its 2007 final rule, when DOE collected a sample of shipping quotations for transporting transformers. In that rulemaking, DOE estimated shipping costs as $0.20 per pound based on an average shipping distance of 1,000 miles. For the preliminary analysis, DOE updated the cost to $0.22 per pound based on the price index for freight shipping between 2007 and 2010. Additional detail on these shipping costs can be found in chapter 5 and chapter 8 of the TSD.

For the NOPR, DOE revised its shipping cost estimate to account for the rising cost of diesel fuel. DOE adjusted its previous shipping cost of $0.20 (in 2006 dollars) from the 2007 final rule to a 2011 cost based on the producer price index for No. 2 diesel fuel. This yielded a shipping cost of $0.28 per pound. DOE also retained its shipping cost calculation based on the weight of the transformer to differentiate the shipping costs between lighter and heavier, typically more efficient, designs.

In the preliminary analysis, DOE applied a non-production markup to all cost components, including shipping costs, to derive the MSP. DOE based this cost treatment on the assumption that manufacturers would mark up the shipping costs when calculating their final selling price. The resulting shipping costs were, as stated, approximately four to eight percent of total MSP.

Based on comments received and DOE's additional research into the treatment of shipping costs through manufacturer interviews, DOE decided to retain the shipping costs in its calculation of MSP, but not to apply any markups to the shipping cost component. Therefore, shipping costs were added separately into the MSP calculation, but not included in the cost basis for the non-production markup. The resulting shipping costs were still in line with the estimate of four to eight percent of MSP for all the dry-type design lines. For the liquid-immersed design lines, the shipping costs ranged from six to twelve percent of MSP and averaged about nine percent of MSP. This practice was retained for the final rule.

7. Baseline Efficiency and Efficiency Levels

DOE analyzed designs over a range of efficiency values for each representative unit. Within the efficiency range, DOE developed designs that approximate a continuous function of efficiency. However, DOE only analyzes incremental impacts of increased efficiency by comparing discrete efficiency benchmarks to a baseline efficiency level. The baseline efficiency level evaluated for each representative unit is the existing energy conservation standard level of efficiency for distribution transformers established either in DOE's 2007 final rule for medium-voltage transformers or by EPACT 2005 for low-voltage transformers. The incrementally higher efficiency benchmarks are referred to as ''efficiency levels'' (ELs) and, along with MSP values, characterize the cost-efficiency relationship above the baseline.

For today's rule, DOE considered several criteria when setting ELs. First, DOE harmonized the efficiency values across single-phase transformers and the per-phase kVA equivalent three-phase transformers. For example, a 50 kVA single-phase transformer would have the same efficiency requirement as a 150 kVA three-phase transformer. This approach is consistent with DOE's methodology from the 2007 final rule and from the preliminary analysis of this rulemaking. Therefore, DOE selected equivalent ELs for several of the representative units that have equivalent per-phase kVA ratings.

Second, DOE selected equally spaced ELs by dividing the entire efficiency range into five to seven evenly spaced increments. The number of increments depended on the size of the efficiency range. This allowed DOE to examine impacts based on an appropriate resolution of efficiency for each representative unit.

Finally, DOE adjusted the position of some of the equally spaced ELs and examined additional ELs. These minor adjustments to the equally spaced ELs allowed DOE to consider important efficiency values based on the results of the software designs. For example, DOE adjusted some ELs slightly up or down in efficiency to consider the maximum efficiency potential of non-amorphous design options. Other ELs were added to consider important benchmark efficiencies, such as the NEMA Premium® efficiency levels for LVDT distribution transformers. Last, DOE considered additional ELs to characterize the maximum-technologically feasible design for representative units where the harmonized per-phase efficiency value would have been unachievable for one of the representative units.

Although DOE's current test procedure specifies a load value at which to test transformers, DOE recognizes that different consumers see real-world loadings that may be higher or lower. In those cases, consumers may choose a transformer offering a lower LCC even when faced with a higher first cost. If DOE's cost/efficiency design cloud were redrawn to reflect loadings other than those specified in the test procedure, different designs would migrate to the optimum frontier of the cloud. Additionally, although DOE's engineering analysis reflects a range of transformers costs for a given EL, the LCC analysis only selects transformer designs near the lowest cost point.

8. Scaling Methodology

a. kVA Scaling

For today's rule, DOE performed a detailed analysis on each representative unit and then extrapolated the results of its analysis from the unit studied to the other kVA ratings within that same engineering design line. DOE performed this extrapolation to develop inputs to the national impacts analysis. The technique it used to extrapolate the findings of the representative unit to the other kVA ratings within a design line is referred to as ''the 0.75 scaling rule.'' This rule states that, for similarly designed transformers, costs of construction and losses scale with the ratio of their kVA ratings raised to the 0.75 power. The relationship is valid where the optimum efficiency loading points of the two transformers being scaled are the same. DOE used the same methodology to scale its findings during the 2007 final rule on distribution transformers.

Because it is not practical to directly analyze every combination of design options and kVAs under the rulemaking's scope of coverage, DOE selected a smaller number of units it believed to be representative of the larger scope. Many of the current design lines use representative units retained from the 2007 final rule with minor modifications. To generate efficiency values for kVA values not directly analyzed, DOE employed a scaling methodology based on physical principles (overviewed in Appendix 5B) and widely used by industry in various forms. DOE's scaling methodology is an approximation and, as with any approximation, can suffer in accuracy as it is extended further from its reference value.

Additionally, DOE modified the way it splices extrapolations from each representative unit to cover equipment classes at large. Previously, DOE extrapolated curves from individual data points and blended them near the boundaries to set standards. Currently, DOE fits a single curve through all available data points in a space and believes that the resulting curve is smoother and offers a more robust scaling behavior over the covered kVA range.

DOE received a number of comments on the matter of scaling across kVA ranges. Cooper Power Systems supported the use of the .75 exponent, though noted that it may not hold for higher kVA values. (Cooper, No. 165 at p. 4) MGLW commented that for single-phase pad-mounted distribution transformers the exponent may approach .75, but that it was not accurate for single-phase pole-mounted distribution transformers, whose curve would be of polynomial form. (MLGW, No. 127 at p. 1) PEMCO proposed to use a curve in logarithmic space, which would create an even more complex behavior in linear coordinates. (PEMCO, No. 183 at p. 2) Progress Energy commented that DOE should avoid scaling altogether, and instead use data from vendors. (PE, No. 192 at p. 6) ABB, APPA, BG&E, EEI, Howard, NEMA, NRECA, Power Partners, Prolec-GE, Commonwealth Edison, and Schneider all commented that DOE's general approach was sound, but that the accuracy of the procedure may be improved with more data-validated modeling. (ABB, No. 158 at p. 7; APPA, No. 191 at pp. 7–8; APPA, No. 237 at p. 3; BG&E, No. 182 at p. 5; EEI, No. 185 at p. 9; HI, No. 151 at p. 12; NEMA, No. 170 at p. 10; NRECA, No. 172 at p. 6; Power Partners, No. 155 at p. 3; Prolec-GE, No. 146 at pp. 82–83; Prolec-GE, No. 177 at p. 10; ComEd, No. 184 at p. 10; Schneider, No. 180 at p. 5)

In the case of equipment class 1, which addresses single-phase liquid-immersed distribution transformers, some stakeholders expressed confusion on the scaling. Because this equipment class contains three design lines and because DOE is deriving a standard using a straight line in logarithmic space, it is possible that the three ELs, one from each design line) may not fall exactly in-line. In that case, as occurred for equipment class one with TSL 1, DOE best fit a straight line through three points. APPA, EEI, Berman Economics, NRECA, Pepco, and the Advocates both commented that because DOE did not propose a standard that aligned with each of these ELs, the economic results were not exact. (APPA, No. 191 at p. 3; Berman Economics, No. 150 at p. 2; NRECA, No. 2; Pepco, No. 145 at pp. 1–2; Advocates, No. 186 at pp. 9–10) DOE thanks the commenters for making that clear, and has revised its presentation of final rule economic results accordingly.

For today's rule, DOE finds the NOPR methodology well-supported by a large number of stakeholders and continues to employ it. DOE believes transformers are approximately well-modeled as power-law devices. In other words, attributes of the devices should grow in proportion to the size raised to a constant power. The ideal, mathematically derived value of that exponent is .75, but in practice transformers may not be constructed ideally and other effects may drive the exponent above or below .75. DOE believes allowing the exponent to float from .75 where justified may help to account for certain size-dependent effects not always well captured by the theoretical .75 result.

b. Phase Count Scaling

In the 2007 final rule, DOE covered both single- and three-phase transformers and harmonized standards across phases. More specifically, DOE set standards such that a single-phase transformer of a certain type (e.g., liquid immersed) and kVA rating (e.g., 100) would be required to meet the same standard as would a three-phase transformer of the same type and three times the kVA rating (in this example, 300 kVA liquid immersed). In certain cases, DOE believes there is sound technological basis for doing so. For example, three-phase liquid-immersed distribution transformers mounted on poles are frequently constructed using three single-phase cores inside of a single housing. Although miscellaneous losses may vary slightly (e.g., bus losses) across three- and single-phase pole-mounted units, one would expect the core-and-coil efficiencies to be identical for a similar construction choices such as steel grade, winding grade, core geometry, etc.

In many other cases, however, there may not be a strong technical basis for strongly coupling single- and three-phase standards. Several parties commented on the matter in response to the NOPR.

Howard Industries and Power Partners both supported linking single- and three-phase standards, as was done in the 2007 final rule. (HI, No. 151 at p. 12; Power Partners, No. 155 at p. 3) ABB, APPA, Cooper, NEMA, Progress Energy, Prolec-GE, and Schneider, however, argued that construction differences resulted in there being no logical reason to link the two standards, and that any standards should be derived from independent analysis of each. (ABB, No. 158 at p. 7; APPA, No. 191 at p. 7; Cooper, No. 165 at p. 3; NEMA, No. 170 at p. 10; NEMA, No. 170 at p. 3; PE, No. 192 at p. 6; Prolec-GE, No. 146 at p. 85; Prolec-GE, No. 177 at p. 9; Schneider, No. 180 at p. 5)

In today's rule, DOE follows the convention of the NOPR and does not impose the constraint that single- and three-phase efficiencies must be linked. DOE notes, however, that standards were harmonized across phase counts in the case of single-phase MVDT equipment classes, where market volume is minimal and direct analysis of such units a lower priority.

9. Material Availability

Throughout this rulemaking, DOE received several comments expressing concern over the availability of materials, including core steel and conductors, needed to build energy efficient distribution transformers. These issues pertain to a global scarcity of materials as well as issues of materials access for small manufacturers.

DOE is aware that many core steels, including amorphous steels, have constraints on their supply and presents an analysis of global steel supply in TSD appendix 3–A.

10. Primary Voltage Sensitivities

DOE understands that primary voltage and the accompanying BIL may increasingly affect efficiency of liquid-immersed transformers as standards rise. DOE may conduct primary voltage sensitivity analysis in order to better quantify the effects of BIL and primary voltage on efficiency, and may use such information to consider establishing equipment classes by BIL rating for liquid-immersed distribution transformers.

11. Impedance

In the engineering analysis, DOE only considered transformer designs with impedances within the normal impedance ranges specified in Table 1 and Table 2 of 10 CFR 431.192. These impedances represent the typical range of impedance that is used for a given liquid-immersed or dry-type transformer based on its kVA rating and whether it is single-phase or three-phase.

Several stakeholders expressed concern over efficiency standards that could potentially cause changes in impedance. Progress Energy, BG&E, NEMA and ComEd all commented that the increased efficiency levels in the 2010 standards resulted in changes in impedance values. (PE, No. 192 at p. 11;

BG&E, No. 182 at p.10; ComEd, No. 184 at p. 15; NEMA, No. 170 at pp. 18–19) ''Manufacturers are already having challenges with transformer designs that meet the efficiencies required in the Final Rule dated October 12, 2007, the minimum impedance requirement of 5.3% and weight limit of 3,600 lbs * * * for select ComEd designs * * * only one of five suppliers from which ComEd is currently purchasing can meet the efficiency, impedance and weight requirements.'' (ComEd, No. 184 at p. 15) Howard Industries concurred that changes in efficiency standards may also change impedance, commenting that for SPS type designs higher efficiency levels typically bring lower impedance which leads to short circuit let-through current. (HI, No. 151 at p. 12) BG&E also noted that if higher efficiency standards drive impedance ranges outside of the IEEE required range, utilities will be forced to change out a whole block of transformers, even if only one is directly affected, to ensure matching impedances and a safe, reliable installation. (BG&E, No. 182 at p. 10) NRECA and APPA second this point, noting that transformers must meet IEEE standards concerning impedance values while simultaneously meeting or exceeding the DOE minimum efficiency standards. (NRECA, No. 172 at p. 11; APPA, No. 191 at p. 14) Schneider Electric pointed out that changes in impedance levels impact the voltage drop of the system and potential increased impedance due to higher efficiency designs could impact overall energy conservation; the impact in line losses from the increased impedance could offset any benefits obtained in the transformer. (Schneider, No. 180 at p. 11) ABB expressed concern that the X/R ratio could rise with increasing standards which could result in higher losses in the distribution system as a whole. It is ABB's opinion that if there is an applicable industry standard for a specific transformer then the X cannot be adjusted as easily and will result in an increased X/R. (ABB, No. 158 at p. 10) Furthermore, it noted that as efficiency increases, resistance decreases, causing a higher X/R ratio. They commented that if there is no applicable industry standard on a specific transformer for impedance values, the X could be offset to correlate with the change in R, however, this would lead to an increase in the percent [voltage] regulation [30] and higher losses in the transformer. If there is an industry standard, the X cannot be adjusted as easily and will result in an increased X/R. (ABB, No. 158 at p. 10) ConEd also pointed out that higher efficiencies may lead to higher inrush currents, which may require installation of more robust and costly distribution components to be installed which would increase costs. (ConEd, No. 236 at p. 4)

On the other hand, various stakeholders claimed that there was no direct relationship between impedance and efficiency levels. EEI commented that they would be concerned if higher standards would make it more difficult for manufacturers to meet the necessary requirements for impedance, inrush current and X/R ratio, but noted that they are not currently aware of any existing direct relationship. (EEI, No. 185 at p. 20) Prolec-GE agreed, noting that they did not see any issues with inrush, X/R ratios, or impedance at the levels proposed in the NOPR. (Prolec-GE, No. 177 at p. 16)

For today's rule, DOE continued to consider only designs within the normal impedance ranges used in the preliminary analysis. DOE believes that this demonstrates the possibility of manufacturing a variety of impedances at efficiencies well in excess of those adopted in today's rule. While certain applications may have specifications that are more stringent than these normal impedance ranges, DOE believes that the majority of applications are able to tolerate impedances within these ranges. Since DOE considers a wide array of designs within the normal impedance ranges, it adequately accounts for the cost considerations of higher and lower impedance tolerances. Furthermore, DOE believes the standards under consideration in the NOPR to be of modest enough increase to minimize serious concern with respect to impedance and X/R ratio.

12. Size and Weight

In the preliminary analysis, DOE did not constrain the weight of its designs. DOE accounted for the full weight of each design generated by the optimization software based on its materials and hardware. Similarly, DOE let several dimensional measurements of its designs vary based on the optimal core/coil dimensions plus space factors. However, DOE did hold certain tank and enclosure dimensions constant for its design lines. Most notably, DOE fixed the height dimension on all of its rectangular tank transformers. For each design that had variable dimensions, DOE accounted for the additional cost of installing the unit, where applicable.

For today's engineering analysis, DOE did not restrict its designs based on a limit for size or weight beyond the fixed height measurements it was already considering for the rectangular tank sizes. DOE understands that larger transformers may require additional installation costs such as a new pole change-out or vault expansion. To the extent that it had data on these additional costs, DOE accounted for them in its LCC analysis, as described in section IV.F. However, DOE did not choose to limit its design specifications based on a specific size or weight constraint.

Nonetheless, DOE notes that the majority of its designs are within weight constraints suggested by stakeholders. In design line 2, over 95 percent of DOE's designs are below 650 pounds. In design line 3, over 62 percent of DOE's designs are below 3,600 pounds, and when only the designs with the lowest first cost are considered, nearly 74 percent of the designs are less than 3,600 pounds. The majority of the designs that exceed 3,600 pounds are at the maximum efficiency levels using an amorphous core steel.

DOE worked with manufacturers to explore the magnitude of the effect of longer buses and leads and found it to be small relative to the gap between efficiency levels. Nonetheless, DOE made small upward adjustments to bus and lead losses of all medium-voltage dry-type design lines. Details on the specific values of the adjustments made can be found in chapter 5 of the TSD.

D. Markups Analysis

The markups analysis develops appropriate markups in the distribution chain to convert the estimates of manufacturer selling price derived in the engineering analysis to customer prices. In the preliminary analysis, DOE determined the distribution channels for distribution transformers, their shares of the market, and the markups associated with the main parties in the distribution chain, distributors, contractors and electric utilities.

Based on comments from interested parties, for the NOPR DOE added a new distribution channel to represent the direct sale of transformers to utilities, which account for approximately 80 percent of liquid-immersed transformer shipments. Howard Industries and Prolec-GE agreed with DOE's estimate that 80 percent of transformers are sold by manufacturers to utilities. (HI, No. 151 at p. 8; Prolec-GE, No. 177 at p. 13) For the final rule, DOE retained this distribution channel.

DOE developed average distributor and contractor markups by examining the installation and contractor cost estimates provided by *RS Means*

[30] In other words, how well a transformer maintains output voltage as load increases.

Electrical Cost Data 2011.[31] DOE developed separate markups for baseline equipment (baseline markups) and for the incremental cost of more-efficient equipment (incremental markups). Incremental markups are coefficients that relate the change in the installation cost due to the increase equipment weight of some higher-efficiency models.

Chapter 6 of the final rule TSD provides additional detail on the markups analysis.

E. Energy Use Analysis

The energy use analysis produced energy use estimates and end-use load shapes for distribution transformers. The energy use estimates enable evaluation of energy savings from the operation of distribution transformer equipment at various efficiency levels, while the end-use load characterization allows evaluation of the impact on monthly and peak demand for electricity.

The energy used by distribution transformers is characterized by two types of losses. The first are no-load losses, which are also known as core losses. No-load losses are roughly constant and exist whenever the transformer is energized (*i.e.,* connected to live power lines). The second are load losses, which are also known as resistance or I^2R losses. Load losses vary with the square of the load being served by the transformer.

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

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

Transformer loading is an important factor in determining which types of transformer designs will deliver a specified efficiency, and for calculating transformer losses. For the NOPR, DOE estimated a range of loading for different types of transformers based on analysis done for the 2007 final rule. During the negotiations the load distributions were presented and found to be reasonable by the parties. In addition, data submitted by Moon Lake Electric during the negotiations were used to validate the load models for single-phase liquid-immersed distribution transformers.

For the NOPR, higher-capacity three-phase liquid-immersed and medium-voltage dry-type transformers were loaded at 20 to 66 percent, and smaller capacity single-phase medium-voltage liquid-immersed transformers were loaded at 20 to 60 percent. Low-voltage dry-type transformers were loaded at 3 to 45 (mean of 25) percent.

Cooper stated that the average loading used for liquid-filled transformers was underestimated, and historical utility evaluation factors suggest 50 percent loading for single-phase liquid-immersed transformers and closer to 60 percent for three-phase liquid-immersed transformers. (Cooper, No. 165 at p. 5) EEI stated that higher capacity three-phase distribution transformers are likely to be serving large industrial facilities with higher loading factors. (EEI, No. 185 at p. 14) Utilities stakeholders responded with a wide range of average loading values that they have on their distribution transformers: ComEd stated that its aggregated load factors range from approximately 40 to 70 percent depending on the customer class. (ComEd, No. 184 at p. 2) MLGW stated that its average aggregated load factor was approximately 17 percent across its distribution system. (MLGW, No. 133 at p. 1) PEPCO agreed that the average aggregate load factors presented in the NOPR were a good compromise and that they should not be changed. (PEMCO, No.183 at p. 2)

As previously mentioned, DOE was able to validate its load models for single-phase liquid-immersed transformers using submitted data, so it retained the loading used in the NOPR for the final rule. For three-phase liquid-immersed transformers, DOE believes that the comment from Cooper does not provide an adequate basis for changing the loading range that was viewed as reasonable by the parties to the negotiation and the loading values provided by utilities comport with DOE's estimated loadings.

Dry-type distribution transformers are primarily installed on buildings and owned by the building owner/operator. Commercial and industrial (C&I) utility customers are typically billed monthly, with the bill based on both electricity consumption and demand. Hence, the value of improved transformer efficiency depends on both the load impacts on the customer's electricity consumption and demand and the customer's marginal prices.

The customer sample of dry-type distribution transformer owners was taken from the EIA Commercial Buildings Energy Consumption Survey (CBECS) databases.[32] Survey data for the years 1992 and 1995 were used, as these are the only years for which monthly customer electricity consumption (kWh) and peak demand (kW) are provided. To account for changes in the distribution of building floor space by building type and size, the weights defined in the 1992 and 1995 building samples were rescaled to reflect the distribution in the most recent (2003) CBECS survey. CBECS covers primarily commercial buildings, but a significant fraction of transformers are shipped to industrial building owners. To account for this in the sample, data from the 2006 Manufacturing Energy Consumption Survey (MECS)[33] were used to estimate the amount of floor space of buildings that might use the type of transformer covered by the rulemaking. The statistical weights assigned to the building sample were rescaled to reflect this additional floor space. Only the weighting of large buildings were rescaled.

[31] RSMeans Electrical Cost Data 2011; 2010; J.H. Chiang, C. Babbitt.

[32] 1992 Commercial Building Energy Consumption and Expenditures Survey (CBECS); 1995; U.S. Department of Energy—Energy Information Administration; *http://www.eia.doe.gov/emeu/cbecs/microdat.html.*

[33] Manufacturing Energy Consumption Survey (MECS); 2006 U.S. Department of Energy—Energy Information Administration; *http://www.eia.gov/emeu/mecs/contents.html.*

F. Life-Cycle Cost and Payback Period Analysis

DOE conducts LCC and PBP analyses to evaluate the economic impacts on individual customers of potential energy conservation standards for distribution transformers.[34] The LCC is the total customer expense over the life of a type of equipment, consisting of purchase and installation costs plus operating costs (expenses for energy use, maintenance and repair). To compute the operating costs, DOE discounts future operating costs to the time of purchase and sums them over the lifetime of the equipment. The PBP is the estimated amount of time (in years) it takes customers to recover the increased purchase cost (including installation) of a more efficient type of equipment through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost (normally higher) due to a more stringent standard by the change in average annual operating cost (normally lower) that results from the standard.

For any given efficiency level, DOE measures the PBP and the change in LCC relative to an estimate of the base-case efficiency levels. The base-case estimate reflects the market in the absence of amended energy conservation standards, including the market for equipment that exceeds the current energy conservation standards.

Equipment price, installation cost, and baseline and standard affect the installed cost of the equipment. Transformer loading, load growth, power factor, annual energy use and demand, electricity costs, electricity price trends, and maintenance costs affect the operating cost. The compliance date of the standard, the discount rate, and the lifetime of equipment affect the calculation of the present value of annual operating cost savings from a proposed standard. Table IV.16 below summarizes the major inputs to the LCC and PBP analysis, and whether those inputs were revised for the final rule.

DOE calculated the LCC and PBP for a representative sample (a distribution) of individual transformers. In this manner, DOE's analysis explicitly recognized that there is both variability and uncertainty in its inputs. DOE used Monte Carlo simulations to model the distributions of inputs. The Monte Carlo process statistically captures input variability and distribution without testing all possible input combinations. Therefore, while some atypical situations may not be captured in the analysis, DOE believes the analysis captures an adequate range of situations in which transformers operate.

TABLE IV.6—KEY INPUTS FOR THE LCC AND PBP ANALYSIS

Inputs	NOPR description	Changes for the final rule
Affecting Installed Costs		
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, DOE used manufacturer selling price plus small distributor markup plus sales tax. Shipping costs were included for both types of transformers.	No change.
Installation cost	Includes a weight-specific component derived from *RS Means Electrical Cost Data 2011* and a markup to cover installation labor, pole replacement costs for design line 2 and equipment wear and tear.	Added pole replacement cost for design line 3.
Baseline and standard design selection.	The selection of baseline and standard-compliant transformers depends on customer behavior. The fraction of purchases evaluated was 10% for liquid-immersed transformers, 2% for low-voltage dry-type and 2% for medium-voltage dry-type transformers.	No change.
Affecting Operating Costs		
Transformer loading	Modeled loading as a function of transformer capacity and utility customer density.	No change.
Load growth	0.5% per year for liquid-immersed and 0% per year for dry-type transformers.	No change.
Power factor	Assumed to be unity	No change.
Annual energy use and demand	Derived from a statistical hourly load simulation for liquid-immersed transformers, and estimated from the 1992 and 1995 *Commercial Building Energy Consumption Survey* data for dry-type transformers using factors derived from hourly load data. Load losses varied as the square of the load and were equal to rated load losses at 100% loading.	No change.
Electricity costs	Derived from tariff-based and hourly based electricity prices. Capacity costs provided extra value for reducing losses at peak.	No change.
Electricity price trend	Obtained from *Annual Energy Outlook 2011* (*AEO2011*)	Updated to AEO 2012. Price trends for liquid-immersed transformers are based on a mix of generating fuel prices.
Maintenance cost	Annual maintenance cost did not vary as a function of efficiency	No change.
Compliance date	Assumed to be 2016	No change.
Discount rates	Mean real discount rates ranged from 3.7% for owners of liquid-immersed transformers to 4.6% for dry-type transformer owners.	No change.
Lifetime	Distribution of lifetimes, with mean lifetime for both liquid and dry-type transformers assumed to be 32 years.	No change.

[34] Customers refer to electric utilities in the case of liquid-immersed transformers, and to utilities and building owners in the case of dry-type transformers.

The following sections contain brief discussions of comments on the inputs and key assumptions of DOE's LCC and PBP analysis and explain how DOE took these comments into consideration.

1. Modeling Transformer Purchase Decision

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

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

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

DOE used evaluation rates as follows: 10 percent of liquid-immersed transformers were evaluated, 2 percent of low-voltage dry-type transformers were evaluated, and 2 percent of medium-voltage dry-type transformers were evaluated. The transformer selection approach is discussed in detail in chapter 8 of the final rule TSD.

2. Inputs Affecting Installed Cost

a. Equipment Costs

In the LCC and PBP analysis, the equipment costs faced by distribution transformer purchasers are derived from the MSPs estimated in the engineering analysis and the overall markups estimated in the markups analysis.

To forecast a price trend for the NOPR, DOE derived an inflation-adjusted index of the PPI for electric power and specialty transformer manufacturing from 1967 to 2010. These data show a long-term decline from 1975 to 2003, and then a steep increase since then. DOE believes that there is considerable uncertainty as to whether the recent trend has peaked, and would be followed by a return to the previous long-term declining trend, or whether the recent trend represents the beginning of a long-term rising trend due to global demand for distribution transformers and rising commodity costs for key transformer components. Given the uncertainty, DOE chose to use constant prices (2010 levels) for both its LCC and PBP analysis and the NIA. For the NIA, DOE also analyzed the sensitivity of results to alternative transformer price forecasts.

DOE did not receive comments on the most appropriate trend to use for real transformer prices, and it retained the approach used for the NOPR for today's final rule.

b. Installation Costs

Higher efficiency distribution transformers tend to be larger and heavier than less efficient designs. The degree of weight increase depends on how the design is modified to improve efficiency. In the NOPR analysis, DOE estimated the increased cost of installing larger, heavier transformers based on estimates of labor cost by transformer capacity from Electrical Cost Data 2011 Book by RSMeans.[35] DOE retained the same approach for the final rule. DOE's analysis of increase in installation labor costs as transformer weight increases is described in detail in chapter 6 of the final rule TSD.

For pole-mounted transformers, represented by design lines (DL) 2 and 3, the increased weight may lead to situations where the pole needs to be replaced to support the additional weight of the transformer. This in turn leads to an increase in the installation cost. To account for this effect in the analysis, three steps are needed:

The first step is to determine whether the pole needs to be changed. This depends on the weight of the existing transformer compared to the weight of the transformer under a proposed efficiency level, and on assumptions about the load-bearing capacity of the pole. In the NOPR analysis, it was assumed that a pole change-out will only be necessary if the weight increase is larger than 15 percent of the weight of the baseline unit, which DOE used to represent the existing transformer, and more than 150 pounds heavier for a design line 2 transformer, and 1,418 pounds heavier for a design line 3 transformer. While EEI stated that it may take less than a 1,418 pound increase for a design line 3 distribution transformer to require a pole change out (EEI, No. 229 at p. 2), neither EEI nor its members provided comments to support a different value. Therefore, DOE believes there is not a compelling reason to change from the approach used in the NOPR. Utility poles are primarily made of wood. Both ANSI[36] and the National Electrical Safety Code (NESC)[37] provide guidelines on how to estimate the strength of a pole based on the tree species, pole circumference and other factors. Natural variability in wood growth leads to a high degree of variability in strength values across a given pole class. Thus, NESC also provides guidelines on reliability, which result in an acceptable probability that a given pole will exceed the minimal required design strength. Because poles are sized to cope with large wind stresses and potential accumulation of snow and ice, this results in ''over-sizing'' of the pole relative to the load by a factor of two to four. Accounting for this ''over-sizing,'' DOE estimated that the total fraction of pole replacements would not exceed 25 percent of the total population. Chapter 6 of the final rule TSD explains the approach used to arrive at this figure.

HI commented that there very likely will be a sizeable number of situations where a new pole may be required, but it noted that DOE's assumption that up to 25 percent of the total pole-mounted transformer population may require pole replacements is probably a reasonable figure. (HI, No. 151 at p. 8) EEI, APPA and NRECA suggested that the pole change-out fraction be increased to as high as 50 percent to 75 percent of units located in cities with populations of at least 25,000. (EEI, No. 185 at p. 14; NRECA, No. 172 at p. 10; APPA, No. 191 at p. 12) EEI, NRECA, and APPA did not provide evidence or rationale to support their suggestion of a higher change-out fraction for urban utilities in their comments. Therefore, DOE believes there is not a compelling reason to change from the approach used in the NOPR.

The second step is to determine the cost of a pole change-out. In the NOPR phase, specific examples of pole change-out costs were submitted by the sub-committee. These examples were consistent with data taken from the

[35] J.H. Chiang, C. Babbitt ; RSMeans Electrical Cost Data 2011; 2010.

[36] American National Standards Institute (ANSI), Wood Poles—Specifications and Dimension, ANSI O5.1.2008, 2008.

[37] Institute of Electrical and Electronics Engineers (IEEE), 2012 National Electrical Safety Code (NESC), IEEE C2–2012, 2012.

RSMeans Building Construction Cost database.[38] Based on this information, for design line 2 with a capacity of 25 kVA, a triangular distribution was used to estimate pole change-out costs, with a lower limit at $2,025 and an upper limit at $5,999. For design line 3 with a capacity of 500 kVA, DOE used a similar distribution with a lower limit of $5,877 and an upper limit of $13,274 for pole replacement, and a distribution with a lower limit of $5,877 and an upper limit of $16,899 for multi-pole (platform) replacement. These costs are in addition to the weight-based installation cost described above.

Utility poles have a finite lifetime so, in some cases, pole change-out due to increased transformer weight should be counted as an early replacement of the pole; i.e., it is not correct to attribute the full cost of pole replacement to the transformer purchase. Equivalently, if a pole is changed out when a transformer is replaced, it will have a longer lifetime relative to the pole it replaces, which offsets some of the cost of the pole installation. To account for this effect, pole installation costs are multiplied by a factor *n/pole-lifetime,* which approximately represents the value of the additional years of life. The parameter *n* is chosen from a flat distribution between 1 and the pole lifetime, which is assumed to be 30 years.[39]

DOE received a number of comments on pole replacement costs. Westar stated that it costs them approximately $2,330 to replace an existing pole with a 50-foot Class 1 pole for a 100 kVA distribution transformer, which might be the new norm for residential areas. It added that whenever they replace a pole they would lose NESC grandfathering for that structure and have to redo everything on the pole to bring it up to the current NESC code, instead of merely switching out the transformer. This results in additional labor. (Westar, No. 169 at p. 2) BG&E commented that DOE's methodology may not reflect the true costs of pole change-outs, as pole replacement costs quoted by industry experts are either estimates or they reflect actual costs from previous years. In BG&E's experience, actual costs tend to exceed the estimates by a significant amount (20 to 60 percent). In 2011, its average pole replacement cost was $7,100, which includes the cost of the new pole along with any replacement material used during the installation. (BG&E, No. 223 at p. 2) ComEd also stated that DOE may have underestimated the cost of pole change-outs. At ComEd, the average pole replacement cost is in the range of $4,000–$5,000, which includes the cost of the new pole along with any replacement material and labor. (ComEd, No. 184 at p. 13) Progress Energy stated that it realized average pole replacement costs of $2,200 during 2011, but it noted that during the negotiated meetings, utilities reported pole replacement costs upwards of $12,000. Progress Energy recommended that DOE continue to use the pole replacement costs that they have been using so that the final rule will not be delayed. (Progress Energy, No. 192 at p. 9) EEI suggested that DOE increase the pole change-out cost estimates to a range of values (or a weighted average) provided by EEI member companies. (EEI, No. 185 at p. 14)

The information that DOE received regarding average pole replacement costs was of limited use because most of the utilities did not provide their average pole replacement costs for the transformer capacities used in the analysis. However, DOE notes that the pole replacement costs mentioned in the above comments fall within the range of costs that DOE used for its pole-mounted design lines (design lines 2 and 3). DOE recognizes that there may be some cases where the pole replacement cost may be outside this range, but these would account for a very small fraction of situations.

Westar stated that when mounting a bank of three-phase transformers on a pole, if the weight increased beyond 2,000 pounds per position (which wouldn't be out of the realm of possibility for a transformer using amorphous core steel), they would need to use a 500kVA pad mount. (Westar, No. 169 at p. 2) DOE recognizes that in some situations pole replacement may not be an acceptable option to utilities when replacing transformers. DOE believes that the range of installation costs that it used for pole replacement, in combination with the weight-based installation costs, captures the cost of situations where a pad mount would be needed.

Westar commented that a new design for a pad-mounted transformer could require larger fiberglass pads than they currently use, or they would have to start pouring a concrete pad for each pad mount. (Westar, No. 169 at p. 3) DOE believes that the installation costs it used for pad-mounted transformers, which range from $2,169 for design line 1 (at 50 kVA) to $8,554 for design line 5 (at 1500 kVA), encompass the situation described by Westar.

3. Inputs Affecting Operating Costs

a. Transformer Loading

DOE's assumptions about loading of different types of transformers are described in section IV.E. DOE generally estimated that the loading of larger capacity distribution transformers is greater than the loading on smaller capacity transformers.

b. Load Growth Trends

The LCC analysis takes into account the projected operating costs for distribution transformers many years into the future. This projection requires an estimate of how the electrical load on transformers will change over time. In the NOPR analysis, for dry-type transformers, DOE assumed no-load growth, while for liquid-immersed transformers DOE used as the default scenario a one-percent-per-year load growth. It applied the load-growth factor to each transformer beginning in 2016. To explore the LCC sensitivity to variations in load growth, DOE included in the model the ability to examine scenarios with zero percent, one percent, and two percent load growth.

DOE did not receive comments regarding its load-growth assumptions, and it retained the assumptions described above for the final rule analysis.

c. Electricity Costs

DOE used estimates of electricity prices and costs to place a value on transformer losses. For the NOPR, DOE performed two types of analyses. One investigated the nature of hourly transformer loads, their correlation with the overall utility system load, and their correlation with hourly electricity costs and prices. Another estimated the impacts of transformer loads and resultant losses on monthly electricity usage, demand, and electricity bills. DOE used the hourly analysis for liquid-immersed transformers, which are owned predominantly by utilities that pay costs that vary by the hour. DOE used the monthly analysis for dry-type transformers, which typically are owned by commercial and industrial establishments that receive monthly electricity bills.

For the hourly price analysis, DOE used marginal costs of electricity, which are the costs to utilities for the last kilowatt-hour of electricity produced. The general structure of the hourly marginal cost equation divides the costs

[38] J.H. Chiang, C. Babbitt; RSMeans Electrical Cost Data 2011; 2010.

[39] As the LCC represents the costs associated with purchase of a single transformer, to account for multiple transformers mounted on a single pole, the pole cost should also be divided by a factor representing the average number of transformers per pole. No data is currently available on the fraction of poles that have more than one transformer, so this factor is not included.

of electricity to utilities into capacity components and energy cost components, which are respectively applied as marginal demand and energy charges for the purpose of determining the value of transformer electrical losses. For each component, DOE estimated the economic value for both no-load losses and load losses.

Commenting on DOE's hourly price analysis, NRECA stated that marginal energy prices recover the system generation capacity costs, and demand charges are not needed to collect capacity charges. (NRECA, No. 156 at pp. 4–5) It added that use of demand charges introduces bias towards improved cost-effectiveness of more efficient transformers. (NRECA, No. 156 at p. 7)

DOE disagrees with NRECA's position that demand charges are not needed to collect capacity charges. DOE agrees that marginal energy prices in a single price-clearing auction can provide for recovery of some amount of generation capacity cost, but it is unlikely that an energy-only market (one that relies only on market incentives for investment) would provide for full recovery of system generation capacity costs.[40] Even with the addition of revenues from an ancillary services market, recovery would likely still fall below the full amount of generation capacity cost for a new generator. Indeed, recent market evaluation reports by the Midwest Independent System Operator (ISO) and California ISO (CAISO) demonstrate that energy and ancillary service market prices in those markets are far below the levels that would be necessary to fully compensate a new generation owner for their generation capacity cost.[41] PJM (a regional transmission operator in the eastern U.S.) addresses the gap between the full going-forward costs[42] and the revenues from energy and ancillary services markets through the addition of a separate capacity market.[43] Most other regions use similar capacity markets or require load serving entities (LSEs) to contract for specified amounts of capacity. Examples of operating regions that use capacity markets or require acquisition of specified levels of capacity include CAISO,[44] MISO,[45] and ISO New England.[46] NRECA acknowledges the existence of capacity markets, but implies that the capacity payments can be ignored because their purpose is to reduce price volatility. (NRECA, No. 156 at p. 5) DOE disagrees with this position because ISOs have stated that the capacity markets and contracts are needed to maintain system reliability, not just mitigate price volatility.[47]

Whether an area has a capacity market or capacity requirements, a reduction in electricity demand due to more efficient transformers would lower the amount of capacity purchases required by LSEs, which would lower capacity procurement costs. DOE's application of demand charges captures these lower procurement costs.

DOE acknowledges that not all electricity markets have structured capacity markets or capacity requirements. The Electric Reliability Council of Texas (ERCOT), an energy-only market without set requirements for generation capacity procurement, is premised on the energy market and the ancillary service markets being able to provide sufficient revenues to attract new market entrants as needed. The expectation is that as reserve margins decline, market prices would increase to provide the needed revenues for new investment. In the long-term, absent the cessation of demand growth, one would expect market revenues to equal the full cost of a new market entrant.[48] Given past market behavior, however, the market revenues will likely be relatively low over many hours and extremely high during a limited number of price spike hours. Accurate modeling and forecasting of price spikes is an extremely difficult task. For the ERCOT region, DOE believes that its capacity cost approach is an appropriate proxy to capture the high price spikes that can occur in energy-only markets.

Many publicly owned utilities (POU) are not required to participate in capacity markets or mandated to attain specified amounts of generation capacity. Capacity attainment is at the sole discretion of those POU's governing bodies, but DOE expects that POUs would continue to build or contract with sufficient capacity to provide reliable service to their customers. As this capacity procurement will impose a cost that is incremental to the utility's system marginal energy cost, the use of capacity costs is also appropriate for evaluation of transformer economics for these utilities.

Although DOE believes it is appropriate to include demand charges, for the final rule, DOE reviewed its capacity cost methodology and found that the demand charges used in the NOPR analysis were too high. In the NOPR, demand charges were based on the full fixed cost of new generation. For the final rule, the revised demand charges are based on the full cost of new generation net of the revenues that the generator could earn from the hourly energy market. This quantification of capacity costs net of market revenues is consistent with the design of the nation's capacity markets, including PJM RPM Capacity Market[49] and the ISO–NE Forward Capacity Market.[50] In addition, this method is used to develop marginal costs for the evaluation of distributed resources, energy efficiency, and demand response programs in regions without organized capacity markets, such as California.[51] The modifications for the final rule significantly reduce the capacity cost used in the LCC analysis. The approach is described further in chapter 8 of the final rule TSD.

In the NOPR, to value the capacity costs, DOE used advanced coal technology to reflect generation capacity

[40] On an ''Energy Only'' Electricity Market Design For Resource Adequacy, 2005; William W. Hogan; *http://www.ferc.gov/EventCalendar/files/20060207132019-hogan_energy_only_092305.pdf.*

[41] CAISO 2011 Market Issues and Performance Report, pp. 45–48, *http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.* MISO 2010 State of the Market Report Executive Summary, Executive Summary, p. viii, *https://www.midwestiso.org/Library/Repository/Report/IMM/2010%20State%20of%20the%20Market%20Report.pdf.*

[42] The term ''going forward costs'' includes, but is not limited to, all costs associated with fuel transportation and fuel supply, administrative and general, and operation and maintenance on a power plant.*http://law.onecle.com/california/utilities/390.html.*

[43] A Review of Generation Compensation and Cost Elements in the PJM Markets, 2009, p. 30, *http://www.pjm.com/~/media/committees-groups/committees/mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx.*

[44] CAISO 2011, p. 181, *http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.*

[45] MISO 2010, p. viii; *https://www.midwestiso.org/Library/Repository/Report/IMM/2010%20State%20of%20the%20Market%20Report.pdf.*

[46] ISO New England 2010 Annual Markets Report, p. 33, *http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf.*

[47] ISO New England 2010, p. 33, *http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf.* PJM 2009, p. 29, *http://www.pjm.com/~/media/committees-groups/committees/mrc/20100120/20100120-item-02-review-of-generation-costs-and-compensation.ashx.* CAISO 2011, p. 181, *http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.* NYISO 2010, p. 156; *http://www.nyiso.com/public/markets_operations/documents/studies_reports/index.jsp.*

[48] If an energy-only market is functioning properly, it must be able to provide sufficient revenues to incent new market entrants over the long term. Failure to incent sufficient generation to provide adequate reliability would likely force a market redesign or the introduction of new LSE obligations such as resource adequacy requirements.

[49] PJM 2009, Executive Summary p. 6.

[50] ISO–NE 2010, p. 33; *http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf.*

[51] See *http://docs.cpuc.ca.gov/efile/PD/162141.pdf.*

costs for no-load loss generation. NRECA stated that substituting the capacity cost of a combustion turbine/combined-cycle plant for the avoided cost of a new coal-fired plant appears to reduce the savings and cost-effectiveness of the more-efficient transformer designs. (NRECA, No. 156 at p. 9) DOE agrees with NRECA's criticism of the approach used for the NOPR. For the final rule DOE assumed that capacity costs for no-load loss generation depend on the type of generation that is built, and that these losses are served by base load capacity. DOE estimated the capacity cost by assuming that marginal capacity is added in the proportions 40 percent coal, 40 percent natural gas combined-cycle, and 20 percent wind. These proportions are based on the capacity mix estimated in the *AEO 2011* projection.

d. Electricity Price Trends

For the relative change in electricity prices in future years, DOE relied on price forecasts from the Energy Information Administration (EIA) *Annual Energy Outlook* (*AEO*). For the final rule analysis, DOE used price forecasts from *AEO 2012.*

In the NOPR, to project the relative change in electricity prices for liquid-immersed transformers, DOE used the average electricity prices from AEO 2011. NRECA stated that gas-fired combustion turbines and combined cycle units are being used to service base loads today, as well as meeting peak demand (NRECA, No. 156 at p. 9), and EEI asserted that natural gas is the marginal fuel ''a lot'' of the time (EEI, No. 0051–0030 at p. 108). DOE agrees with both of these statements. For the final rule, DOE assumed that future production cost of electricity for utilities, the primary owners of liquid-immersed transformers, would be influenced by the price of fuel for generation (i.e., coal and natural gas). To estimate the relative change in the price to produce electricity in future years in today's rule, DOE applied separate price trends to both no-load and load losses. DOE used the sales weighted price trend of both natural gas and coal to estimate the relative price change for no-load losses; and natural gas only to estimate the relative price change for load losses. These trends are based on the AEO 2012 projections and are described in greater detail in chapter 8 of the TSD.

Appendix 8–D of this final rule TSD provides a sensitivity analysis for equipment of a sub-set of representative design lines. These analysis shows that the effect of changes in electricity price trends, compared to changes in other analysis inputs, is relatively small.

e. Standards Compliance Date

DOE calculated customer impacts as if each new distribution transformer purchase occurs in the year that manufacturers must comply with the standard. As discussed in section II.A, if DOE finds that amended standards for distribution transformers are warranted, DOE agreed to publish a final rule containing such amended standards by October 1, 2012. The compliance date of January 1, 2016, provides manufacturers with over three years to prepare for the amended standards.

f. Discount Rates

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

More detail regarding DOE's estimates of commercial customer discount rates is provided in chapter 8 of the final rule TSD.

g. Lifetime

DOE defined distribution transformer life as the age at which the transformer retires from service. For the NOPR analysis, DOE estimated, based on a report by Oak Ridge National Laboratory,[52] that the average life of distribution transformers is 32 years. This lifetime estimate 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 starting at year 15. DOE did not receive any comments on transformer lifetime and it retained the NOPR approach for the final rule.

h. Base Case Efficiency

To determine an appropriate base case against which to compare various potential standard levels, DOE used the purchase-decision model described in section IV.F.1. For the base case, initially transformer purchasers are allowed to choose among the entire range of transformers at each design line. Transformers are chosen based on either lowest first cost, or if the purchaser is an evaluator, on lowest Total Owning Cost (TOC). During the negotiations (see section II.B.2) manufacturers and utilities stated that ZDMH is not currently used in North America, so designs using ZDMH as a core steel were excluded from the base case.

i. Inputs to Payback Period Analysis

The payback period is the amount of time it takes the consumer to recover the additional installed cost of more efficient products, compared to baseline products, through energy cost savings. Payback periods are expressed in years. Payback periods that exceed the life of the product mean that the increased total installed cost is not recovered in reduced operating expenses.

The inputs to the PBP calculation are the total installed cost of the product to the customer for each efficiency level and the average annual operating expenditures for each efficiency level. The PBP calculation uses the same inputs as the LCC analysis, except that discount rates are not needed.

j. Rebuttable-Presumption Payback Period

As noted above, EPCA, as amended, establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the energy (and, as applicable, water) savings during the first year that the consumer will receive as a result of the standard, as calculated under the test procedure in place for that standard. (42 U.S.C. 6295(o)(2)(B)(iii)) For each considered efficiency level, DOE determines the value of the first year's energy savings by calculating the quantity of those savings in accordance with the applicable DOE test procedure, and multiplying that amount by the average energy price forecast for the year in which compliance with the amended standards would be required.

G. National Impact Analysis—National Energy Savings and Net Present Value Analysis

DOE's NIA assessed the national energy savings (NES) and the national NPV of total customer costs and savings that would be expected to result from amended standards at specific efficiency

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

levels. (''Customer'' refers to purchasers of the equipment being regulated.)

To make the analysis more accessible and transparent to all interested parties, DOE used an MS Excel spreadsheet model to calculate the energy savings and the national customer costs and savings from each TSL.[53] DOE used the NIA spreadsheet to calculate the NES and NPV, based on the annual energy consumption and total installed cost data from the energy use characterization and the LCC analysis. DOE forecasted the energy savings, energy cost savings, equipment costs, and NPV of customer benefits for each product class for equipment sold from 2016 through 2045. The forecasts provided annual and cumulative values for all four output parameters. In addition, DOE analyzed scenarios that used inputs from the *AEO 2012* Low Economic Growth and High Economic Growth cases. These cases have higher and lower energy price trends compared to the reference case. NIA results based on these cases are presented in appendix 10–B of the final rule TSD.

DOE evaluated the impacts of amended standards for distribution transformers by comparing base-case projections with standards-case projections. The base-case projections characterize energy use and customer costs for each equipment class in the absence of amended energy conservation standards. DOE compared these projections with projections characterizing the market for each equipment class if DOE were to adopt amended standards at specific energy efficiency levels (i.e., the standards cases) for that class.

Table IV.27 and Table IV.38 summarize all the major NOPR inputs to the shipments analysis and the NIA, and whether those inputs were revised for the final rule.

TABLE IV.7—INPUTS FOR THE SHIPMENTS ANALYSIS

Input	NOPR description	Changes for final rule
Shipments data	Third-party expert (HVOLT) for 2009	No change.
Shipments forecast	2016–2045: Based on *AEO 2011*	Updated to AEO 2012.
Dry-type/liquid-immersed market shares.	Based on EIA's electricity sales data and *AEO2011*	Updated to AEO 2012.
Regular replacement market	Based on a survival function constructed from a Weibull distribution function normalized to produce a 32-year mean lifetime *.	No change.
Elasticities, liquid-immersed	For liquid-immersed transformers • Low: 0.00 • Medium: −0.04 • High: −0.20	No change.
Elasticities, dry-type	For dry-type transformers • Low: 0.00 • Medium: −0.02 • High: −0.20	No change.

* Source: ORNL 6804/R1, *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance,* page D–1.

TABLE IV.8—INPUTS FOR THE NATIONAL IMPACT ANALYSIS

Input	NOPR description	Changes for the final rule
Shipments	Annual shipments from shipments model	No change.
Compliance date of standard	January 1, 2016	No change.
Equipment Classes	Separate ECs for single- and three-phase liquid-immersed distribution transformers.	No change
Base case efficiencies	Constant efficiency through 2044. Equal to weighted-average efficiency in 2016.	No change.
Standards case efficiencies	Constant efficiency at the specified standard level from 2016 to 2044	No change.
Annual energy consumption per unit	Average rated transformer losses are obtained from the LCC analysis, and are then scaled for different size categories, weighted by size market share, and adjusted for transformer loading (also obtained from the LCC analysis).	No change.
Total installed cost per unit	Weighted-average values as a function of efficiency level (from LCC analysis).	No change.
Electricity expense per unit	Energy and capacity savings for the two types of transformer losses are each multiplied by the corresponding average marginal costs for capacity and energy, respectively, for the two types of losses (marginal costs are from the LCC analysis).	No change.
Escalation of electricity prices	*AEO 2011* forecasts (to 2035) and extrapolation for 2044 and beyond	Updated to AEO 2012.
Electricity site-to-source conversion	A time series conversion factor; includes electric generation, transmission, and distribution losses.	No change
Discount rates	3% and 7% real	No change.
Present year	2010	2012.

[53] DOE understands that MS Excel is the most widely used spreadsheet calculation tool in the United States and there is general familiarity with its basic features. Thus, DOE's use of MS Excel as the basis for the spreadsheet models provides interested parties with access to the models within a familiar context. In addition, the TSD and other documentation that DOE provides during the rulemaking help explain the models and how to use them, and interested parties can review DOE's analyses by changing various input quantities within the spreadsheet.

1. Shipments

DOE projected transformer shipments for the base case by assuming that long-term growth in transformer shipments will be driven by long-term growth in electricity consumption. The detailed dynamics of transformer shipments is highly complex. This complexity can be seen in the fluctuations in the total quantity of transformers manufactured as expressed by the U.S. Department of Commerce, Bureau of Economic Analysis (BEA), transformer quantity index. DOE examined the possibility of modeling the fluctuations in transformers shipped using a bottom-up model where the shipments are triggered by retirements and new capacity additions, but found that there were not sufficient data to calibrate model parameters within an acceptable margin of error. Hence, DOE developed the transformer shipments projection by assuming that annual transformer shipments growth is equal to growth in electricity consumption as given by the *AEO 2012* forecast through 2035. For the years from 2036 to 2045, DOE extrapolated the *AEO 2012* forecast with the growth rate of electricity consumption from 2025 to 2035. The model starts with an estimate of the overall growth in transformer capacity and then estimates shipments for particular design lines and transformer sizes using estimates of the recent market shares for different design and size categories. Chapter 9 of the final rule TSD provides a detailed description of how DOE projected shipments for each of the equipment classes in today's final rule.

DOE recognizes that increase in transformer prices due to standards may cause changes in purchase of new transformers. Although the general trend of utility transformer purchases is determined by increases in generation, utilities conceivably exercise some discretion in how much transformer capacity to buy—the amount of ''over-capacity'' to purchase. In addition, some utilities may choose to refurbish transformers rather than purchase a new transformer if the price of the latter increases significantly.

To capture the customer response to transformer price increase, DOE estimated the customer price elasticity of demand. In DOE's estimation of the purchase price elasticity, it used a logit function to characterize the utilities' response to the price of a unit capacity of transformer. The functional form captures what can be called an average price elasticity of demand with a term to capture the estimation error, which accounts for all other effects. Although DOE was not able to explicitly model the replace versus refurbish decision due to lack of necessary data, the price elasticity should account for any decrease in the shipments due to a decision on the customer's part to refurbish transformers as opposed to purchasing a new unit. DOE's approach is described in chapter 9 of the final rule TSD. Comments on the issue of replacing versus refurbishing are discussed in section IV.O.3 of this preamble.

2. Efficiency Trends

DOE did not include any base case efficiency trend in its shipments and national energy savings models. AEO forecasts show no long term trend in transmission and distribution losses, which are indicative of transformer efficiency. DOE estimates that the probability of an increasing efficiency trend and the probability of a decreasing efficiency trend are approximately equal, and therefore assumed no trend in base case or standards case efficiency.

3. National Energy Savings

For each year in the forecast period, DOE calculates the national energy savings for each standard level by multiplying the stock of products affected by the energy conservation standards by the per-unit annual energy savings. Cumulative energy savings are the sum of the NES for each year.

To estimate national energy savings, DOE uses a multiplicative factor to convert site energy consumption into primary energy consumption (the energy required to convert and deliver the site energy). This conversion factor accounts for the energy used at power plants to generate electricity and losses in transmission and distribution. The conversion factor varies over time because of projected changes in the power plant types projected to provide electricity to the country. The factors that DOE developed are marginal values, which represent the response of the system to an incremental decrease in consumption associated with standards. For today's rule, DOE used annual conversion factors based on the version of NEMS that corresponds to *AEO 2012,* which provides energy forecasts through 2035. For 2036–2047, DOE used conversion factors that remain constant at the 2035 values.

Section 1802 of EPACT 2005 directed DOE to contract a study with the National Academy of Science (NAS) to examine whether the goals of energy efficiency standards are best served by measuring energy consumed, and efficiency improvements, at the actual point of use or through the use of the full-fuel-cycle, beginning at the source of energy production. (Pub. L. 109–58 (August 8, 2005)). NAS appointed a committee on ''Point-of-Use and Full-Fuel-Cycle Measurement Approaches to Energy Efficiency Standards'' to conduct the study, which was completed in May 2009. The NAS committee defined full-fuel-cycle energy consumption as including, in addition to site energy use: Energy consumed in the extraction, processing, and transport of primary fuels such as coal, oil, and natural gas; energy losses in thermal combustion in power generation plants; and energy losses in transmission and distribution to homes and commercial buildings.

In evaluating the merits of using point-of-use and full-fuel-cycle (FFC) measures, the NAS committee noted that DOE uses what the committee referred to as ''extended site'' energy consumption to assess the impact of energy use on the economy, energy security, and environmental quality. The extended site measure of energy consumption includes the energy consumed during the generation, transmission, and distribution of electricity but, unlike the full-fuel-cycle measure, does not include the energy consumed in extracting, processing, and transporting primary fuels. A majority of the NAS committee concluded that extended site energy consumption understates the total energy consumed to make an appliance operational at the site. As a result, the NAS committee recommended that DOE consider shifting its analytical approach over time to use a full-fuel-cycle measure of energy consumption when assessing national and environmental impacts, especially with respect to the calculation of greenhouse gas (GHG) emissions. For those appliances that use multiple fuels, the NAS committee indicated that measuring full-fuel-cycle energy consumption would provide a more complete picture of energy consumed and permit comparisons across many different appliances, as well as an improved assessment of impacts.

In response to the NAS committee recommendations, on August 18, 2011, DOE announced its intention to use full-fuel-cycle measures of energy use and greenhouse gas and other emissions in the national impact analyses and emissions analyses included in future energy conservation standards rulemakings. 76 FR 51282 While DOE stated in that notice that it intended to use the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model to conduct the analysis, it also said it would review alternative methods, including the use of NEMS. After evaluating both models and the approaches discussed in the August 18, 2011 notice, DOE has determined NEMS is a more appropriate tool for this specific use. Therefore, DOE intends to use the NEMS model, rather than the GREET model, to conduct future FFC analyses. 77 FR 49701 (Aug. 17, 2012). DOE did not incorporate FFC measures into today's final rule because it did not want to introduce a new method in the final phase of a rulemaking. Rather, in today's rule, DOE continues to use its standard measures of energy use and greenhouse gas and other emissions in the national impact analyses and emissions analyses.

4. Equipment Price Forecast

As noted in section IV.F.2, DOE assumed no change in transformer prices over the 2016–2045 period. In addition, DOE conducted sensitivity analysis using alternative price trends. Based on PPI data for electric power and specialty transformer manufacturing, DOE developed one forecast in which prices decline after 2010, and one in which prices rise. These price trends, and the NPV results from the associated sensitivity cases, are described in appendix 10–C of the final rule TSD.

5. Net Present Value of Customer Benefit

The inputs for determining the net present value (NPV) of the total costs and benefits experienced by consumers of considered appliances are: (1) Total annual installed cost; (2) total annual savings in operating costs; and (3) a discount factor. DOE calculates net savings each year as the difference between the base case and each standards case in total savings in operating costs and total increases in installed costs. DOE calculates operating cost savings over the life of each product shipped during the forecast period.

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. DOE estimates the NPV using both a 3-percent and a 7-percent real discount rate, in accordance with guidance provided by the Office of Management and Budget (OMB) to Federal agencies on the development of regulatory analysis.[54] The discount rates for the determination of NPV are in contrast to the discount rates used in the LCC analysis, which are designed to reflect a consumer's perspective. The 7-percent real value is an estimate of the average before-tax rate of return to private capital in the U.S. economy. The 3-percent real value represents the ''social rate of time preference,'' which is the rate at which society discounts future consumption flows to their present value.

H. Customer Subgroup Analysis

In analyzing the potential impacts of new or amended standards, DOE evaluates impacts on identifiable groups (i.e., subgroups) of customers that may be disproportionately affected by a national standard.

A number of parties expressed specific concerns about size and space constraints for network/vault transformers. (BG&E, No. 182 at p. 6; ComEd, No. 184 at p. 11; Pepco, No. 145 at pp. 2–3; PE, No. 192 at p. 8; Prolec-GE, No. 177 at p. 12)

For today's final rule, DOE evaluated purchasers of vault-installed transformers (mainly utilities concentrated in urban areas), represented by design lines 4 and 5, as a customer subgroup, and examined the impact of standards on these groups using the methodology of the LCC and PBP analysis. DOE examined the impacts of larger transformer volume with regard to costs for vault enlargement. DOE assumed that if the volume of a unit in a standard case is larger than the median volume of transformer designs for the particular design line, a vault modification would be warranted. To estimate the cost, DOE compared the difference in volume between the unit selected in the base case against the unit selected in the standard case, and applied fixed and variable costs. In the 2007 final rule, DOE estimated the fixed cost as $1,740 per transformer and the variable cost as $26 per transformer cubic foot.[55] For today's notice, these costs were adjusted to 2011$ using the chained price index for non-residential construction for power and communications to $1,886 per transformer and $28 per transformer cubic foot. DOE considered instances where it may be extremely difficult to modify existing vaults by adding a very high vault replacement cost option to the LCC spreadsheet. Under this option, the fixed cost is $30,000 and the variable cost is $733 per transformer cubic foot.

The customer subgroup analysis is discussed in detail in chapter 11 of the final rule TSD.

I. Manufacturer Impact Analysis

1. Overview

DOE performed a manufacturer impact analysis (MIA) to estimate the financial impact of amended energy conservation standards on manufacturers of distribution transformers and to calculate the impact of such standards on employment and manufacturing capacity. The MIA has both quantitative and qualitative aspects. The quantitative part of the MIA primarily relies on the Government Regulatory Impact Model (GRIM), an industry cash-flow model with inputs specific to this rulemaking. The key GRIM inputs are data on the industry cost structure, product costs, shipments, and assumptions about markups and conversion expenditures. The key output is the INPV. Different sets of shipment and markup assumptions (scenarios) will produce different results. The qualitative part of the MIA addresses factors such as product characteristics, impacts on particular sub-groups of firms, and important market and product trends. The complete MIA is outlined in chapter 12 of the TSD.

2. Product and Capital Conversion Costs

New and amended energy conservation standards will cause manufacturers to incur conversion costs to bring their production facilities and product designs into compliance. For the MIA, DOE classified these conversion costs into two major groups: (1) Product conversion costs and (2) capital conversion costs. DOE's estimates of the product and capital conversion costs for distribution transformers can be found in section V.B.2.a of today's final rule and in chapter 12 of the TSD.

a. Product Conversion Costs

Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make product designs comply with the new or amended energy conservation standard. DOE based its estimates of the product conversion costs that would be required to meet each TSL on information obtained from manufacturer interviews, the engineering analysis, and the NIA shipments analysis. For the distribution transformer industry, a large portion of product conversion costs will be related to the production of amorphous cores, which would require the development of new designs, materials management, and safety measures. Procurement of such technical expertise may be particularly difficult for manufacturers

[54] OMB Circular A–4 (Sept. 17, 2003), section E, ''Identifying and Measuring Benefits and Costs. Available at: *www.whitehouse.gov/omb/memoranda/m03-21.html.*

[55] See section 7.3.5 of the 2007 final rule TSD, available at *http://www1.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/transformer_fr_tsd/chapter7.pdf.*

without experience using amorphous steel.

b. Capital Conversion Costs

Capital conversion costs are investments in property, plant, and equipment necessary to adapt or change existing production facilities such that new equipment designs can be fabricated and assembled. For capital conversion costs, DOE prepared bottom-up estimates of the costs required to meet standards at each TSL for each design line. To do this, DOE used equipment cost estimates provided by manufacturers and equipment suppliers, an understanding of typical manufacturing processes developed during interviews and in consultation with subject matter experts, and the properties associated with different core and winding materials. Major drivers of capital conversion costs include changes in core steel type (and thickness), core weight, core stack height, and core construction techniques, all of which are interdependent and can vary by efficiency level. DOE uses estimates of the core steel quantities needed for each steel type, as well as the most likely core construction techniques, to model the additional equipment the industry would need to meet the efficiencies embodied by each TSL.

3. Markup Scenarios

In the NOPR MIA, DOE modeled two standards-case markup scenarios to represent the uncertainty regarding the potential impacts on prices and profitability for manufacturers following the implementation of amended energy conservation standards: (1) A preservation of gross margin percentage markup scenario, and (2) a preservation of operating profit markup scenario. These scenarios lead to different markups values, which, when applied to the inputted MPCs, result in varying revenue and cash flow impacts. While DOE has modified several inputs to the GRIM for today's final rule, it continues to analyze these two markup scenarios for the final rule. For a complete discussion, see the NOPR or chapter 12 of the TSD.

4. Other Key GRIM Inputs

Key inputs to the GRIM characterize the distribution transformer industry cost structure, investments, shipments, and markups. For today's final rule, DOE made several updates to the GRIM to reflect changes in these inputs since publication of the NOPR. Specifically, DOE incorporated changes made in the engineering analysis and NIA, including updates to the MPCs, shipment forecasts, and shipment efficiency distributions. In addition, DOE made minor changes to its conversion cost methodology in response to comments as described below. These updated inputs affected the values calculated for the conversion costs and markups described above, as well as the INPV results presented in section V.B.2.

5. Discussion of Comments

The following section discusses a number of comments DOE received on the February 2012 NOPR MIA methodology. DOE has grouped the comments into the following topics: Core steel, small manufacturers, conversion costs, and benefits versus burdens.

a. Core Steel

The issue of core steel is critical to this rulemaking. This section discusses comments related to steel price projections, steel mix and competition between suppliers, and steel supply and production capacity. Most of these issues are highly interconnected.

Steel Prices. Several stakeholders commented on the steel prices used by DOE. Prolec-GE believes that the steel supply assessment in appendix 3A of the TSD was too optimistic about supply and price in a post-recession global environment and that any analysis for higher than current level efficiencies should evaluate a much higher range of material price variance that what DOE used in the NOPR. (Prolec-GE, No. 52 at p. 13) APPA notes that the analysis in appendix 3A of the TSD provides good information about prices from 2006 to 2010, but it does not include information about the significant increase in prices compared to 2002–2003 levels.

Northeast Energy Efficiency Partnerships argued that, when faced with competition, conventional high-grade electrical steel prices could come down and compete effectively with the more efficient amorphous materials. (NEEP, No. 193 at p. 3) Earthjustice expressed similar sentiments, stating that the analysis conducted by DOE on DL1 presents an unrealistic picture of the LCC impacts of meeting TSLs 2 and 3 with conventional steels in that design line because competitive pressure from amorphous metal will likely reduce the price for grain-oriented electrical steels and, therefore, improve the LCC savings for consumers. (Earthjustice, No. 195 at p. 1–3)

DOE recognizes that steel prices have proven highly volatile in the past and could continue to fluctuate in the future for a variety of reasons, including macroeconomic factors, competition among steel suppliers, trade policy and raw material prices. With respect to Earthjustice's comment, while DOE agrees that the LCC is highly sensitive to relative steel price assumptions at certain TSLs, DOE notes that a decline in silicon transformer prices would be unlikely to materially change the slope of the silicon steel transformer cost curve. Therefore, the incremental costs (and LCC savings) would not change significantly. To NEEP's comment, DOE agrees that competition between silicon steel suppliers, the incumbent amorphous metal suppliers and new market entrants will impact future prices. However, DOE does not believe it is possible to predict the relative movements in these prices. Throughout the negotiation process, stakeholders have argued for different price points for different steels under different scenarios. The eventual relative prices of steels in the out years will be in part subject to the aforementioned market forces, the direction and magnitude of which cannot be known at this time. For these reasons, DOE performed a sensitivity analysis that included a wide range of potential core steel prices to evaluate their impact on LCC savings as discussed in section V.B.3.

Diversity of Steel Mix and Competition. Most stakeholders stated a preference for a market in which traditional and amorphous steel could effectively compete, but there was disagreement over which efficiency level would strike that balance, particularly for liquid-immersed distribution transformers. The various steel types that are available on the market for distribution transformers are listed in Table 5.10 in chapter 5 of the TSD. Stakeholders generally sought a standard that would allow manufacturers to use a diversity of electrical steels that are cost-competitive and economically feasible. This issue is critical to stakeholders for several reasons, including what some worried would be a lack of amorphous steel supply, a transition to a market that currently has only one global supplier with significant capacity, as well as forced conversion costs associated with the manufacturing of amorphous steel cores.

Both APPA and Adams Electric Cooperative (AEC) commented that it is important that DOE preserve the competitive market by allowing both grain-oriented steel and amorphous core transformers to be price competitive. APPA and AEC are concerned about the availability and price of the core materials if only one product is competitively viable because this will affect jobs for traditional steel manufacturers and also small transformer manufacturers that may not be able to afford or have the expertise to convert their plants to accommodate amorphous core construction. (APPA, No. 191 at p. 5; AEC, No. 163 at p. 3) Wisconsin Electric also stated that it is important to have a mix of suppliers available to keep the price of amorphous steel in check and to mitigate the risk of unforeseen situations, such as natural disasters. (Wisconsin Electric, No. 168 at p. 2)

Some stakeholders, in particular ACEEE, ASAP, NRDC, and Northwest Power and Conservation Council (NPCC), asserted that competition can still be maintained at efficiency levels higher than those proposed in the NOPR. These stakeholders believe that TSL 1 favors silicon steel and will, therefore, raise the price for silicon steel while relegating amorphous steel to niche status, relative to a higher TSL. They noted that industry sources and press accounts confirm that electrical steel is a very high profit margin product and the lack of strong competition for M3 in the current market appears to be contributing to very high M3 prices. (Advocates, No. 186 at p. 10) Therefore, the Advocates argued that a modified TSL 4 (EL2 for all design lines) for liquid-immersed transformers could be met using either amorphous metal or silicon steel, thereby increasing competition. ASAP had suggested during the NOPR public meeting that moving into a market where there would be three domestically based competitors would be a better competitive outcome than the status quo of two competitors who have the lion's share of the market. (ASAP, No. 146 at p. 38) In response to the supplementary analysis of June 20, 2012, the Advocates suggested the adoption of TSL C, which they believed would provide for robust competition among core material suppliers. (Advocates, No. 235 at p. 1) They also noted that TSL D, which consists of EL 2 for pad-mounted transformers and EL 1 for pole-mounted transformers, would favor the continued use of grain oriented electrical steel for the majority of the market and allow silicon steel and amorphous metal to reach rough cost parity for pad-mounted transformers. (Advocates, No. 235 at p. 4) ACEEE, ASAP, NRDC, and NPCC further cited some transformer manufacturers as saying TSL 4 or 3.5 (EL 2 or EL 1.5) for liquid-immersed transformers would lead to robust competition because a market currently served by two steel suppliers (AK Steel and ATI Allegheny Ludlum) would then be served by three since the amorphous metal supplier (Metglas) could compete. (Advocates, No. 186 at p. 10–11) Additional amorphous metal suppliers may also enter the market because barriers to entry into amorphous metal transformer production are, according to Metglas, quite limited. (Metglas, No. 102 at p. 2) Also, based on the results of an analysis conducted by an industry expert for ASAP, the Advocates believe that it would be very unlikely that TSL 4 standards from the NOPR for liquid-immersed transformers would result in amorphous metal market share exceeding 20 percent in the near- and medium-term due to the current dominant position of silicon steel, inertia in utility decision making, and the ability of steel makers to lower prices to protect against market share erosion. Furthermore, increases in the standards for LVDT and MVDT transformers, which have markets where amorphous metal does not compete and is not expected to compete at the levels proposed by DOE, will increase silicon steel tonnage. In the longer term, silicon steel manufacturers can make strategic investment decisions that will enable them to compete, such as increasing production of High B steel or entering amorphous metal production. (Advocates, No. 186 at pp. 12–13) Berman Economics also argued that competition between traditional and amorphous steel is still possible with higher standards for liquid-immersed transformers because, according to shipments data from ABB, TSL 4 has the greatest diversity of core materials. (Berman Economics, No. 221 at p. 7)

On the other hand, many stakeholders believe that competition among steel suppliers will not be possible at levels higher than those proposed in the NOPR. At the NOPR public meeting, ATI stated that the proposed standards maintain a competitive balance between alternative materials and grain-oriented electrical steel, which has adequate supply from annual global production levels exceeding two million metric tons and price competition from several producers. (ATI, No. 146 at p. 18) ATI believes that higher standards will result in cost-effective design options limited to amorphous metal cores for liquid-immersed transformers. Such a situation would cost U.S. jobs, increase the risk of supply shortages and disruptions, and create a non-competitive market for new liquid-immersed designs which ATI expects will eliminate any projected LCC savings. (ATI, No. 54 at p. 2) Furthermore, ATI stated that even TSL 1 may have adverse impacts on competition because the efficiency levels assigned to design lines 2 and 5 in TSL 1 were set well above the crossover point for competition between multiple core materials and therefore the implementation of TSL 1 would curtail the availability of multiple options for core material choices for liquid-immersed transformers. ATI did not support any of the new TSLs proposed in DOE's supplementary analysis, which were higher than TSL 1 and which would, according to ATI, have significant impacts on the competitiveness of grain-oriented electrical steel and result in nearly complete conversion of the liquid-immersed market to amorphous cores. (ATI Allegheny, No. 218 at p. 1) Instead, ATI proposed an alternative TSL which consists of what it believes are more accurate crossover points for the liquid-immersed design lines: EL 1.3 for DL 1, EL 0 for DL2, EL 0.7 for DL 3, EL 1 for DL 4, and EL 0.7 for DL 5. (ATI Allegheny, No. 218 at p. 1)

Cooper Power stated that the currently proposed efficiency levels are at the maximum levels that allow use of both silicon and amorphous core steels. Higher efficiency levels will tip the market in favor of amorphous materials that are not available in the quantities needed and do not have the desired diversity of suppliers to maintain a healthy market. (Cooper Power, No. 165 at p. 4) Cooper Power had found through one of its analyses that the crossover point at which transformer price is equivalent between M3 and amorphous was at EL 0.5 for all design lines 1, 3, 4, and 5 and EL 0.25 for DL2. According to Cooper Power, the best choice for raising the efficiency levels and keeping both M3 core steel and amorphous core steel competitive with one another would be to choose EL 0.5. (Cooper Power Systems, No. 222 at p. 2) During the NOPR public meeting, Cooper Power commented that, past EL 1, it is no longer a level playing field between amorphous and silicon core steel. (Cooper Power, No. 146, at p. 49–50) HVOLT also commented that the crossover point between M3 and amorphous is at EL 1, and it's a hard move to amorphous past that level. (HVOLT, No. 146 at p. 51) The United Auto Workers (UAW) is concerned that requiring efficiency levels beyond TSL–1 for liquid-immersed transformers would impose unwarranted conversion costs on transformer producers, force the use of amorphous metals that are not available in adequate supply, and create significant anticompetitive market power for the producer of amorphous metal electrical steel. (UAW, No. 194 at

p. 2) EEI is very concerned about the availability of steels if DOE decides to increase any efficiency levels above those proposed in the NOPR because, as DOE's life-cycle analyses have shown, the ''tipping'' point where many domestic steelmakers are not competitive is usually at levels that are equal to or less than TSL 1 for liquid-immersed transformers. Domestic steelmakers agreed, explaining that the anticompetitive ramifications of a decision to promulgate a standard greater than TSL 1 for the liquid-immersed market would not be economically justified. According to AK Steel and ATI, since amorphous metal is currently competitive but may not be in sufficient supply, and non-amorphous manufacturers may not be able to compete with amorphous metal on a first-cost basis beyond TSL 1, any decision by DOE to promulgate a standard greater than TSL 1 would transfer significant market power, including potential price increases, to the maker of amorphous metal. (AK Steel and ATI, No. 188 at p. 2–3) AK Steel also commented that DOE should finalize a standard equivalent to TSL 1 from the NOPR rather than adopt the new TSLs A through D proposed in the supplementary analysis because it believes that the new TSLs, which are more stringent, would have significant anticompetitive effects that will harm both electric utilities and the public through increased prices. (AK Steel, No. 230 at p. 12–13) NEMA supports the currently proposed efficiency levels because higher levels will tip the scale in favor of amorphous materials that are not available in the quantities needed and do not have the desired diversity of suppliers to maintain a healthy market. (NEMA, No. 170 at p. 14) In response to the supplementary analysis, NEMA argued that the new TSLs (with the exception of TSL A if DL 2 remains at EL 0) would all result in steel supply shortages or a bias in favor of amorphous. (NEMA, No. 225 at p. 4) AEC believes that DOE appropriately balanced high transformer efficiency with a viable competitive market in the NOPR. (AEC, No. 163 at p. 3) NRECA agreed, stating that DOE has achieved the correct balance of high transformer efficiency while maintaining a viable competitive market, because any efficiency level above those recommended in the NOPR will greatly impact competition and, therefore, affect jobs for steel manufacturers and small transformer manufacturers that may not have the resources to convert their plants to accommodate amorphous core construction. (NRECA, No. 228 at p. 4) Likewise, the United Steelworkers Union (USW) supports the currently proposed efficiency levels because they allow end-users to choose between competing technologies rather than relying on a single option. (USW, No. 148 at p. 2)

DOE recognizes the importance of maintaining a competitive market for transformer steel supply in which traditional steel and amorphous steel suppliers can both participate. This was a critical consideration in DOE's assessment of the rule's impact on competition. As with the discussion on future prices, the precise ''crossover point'' is variable depending on a number of factors, including firm pricing strategies, global demand and supply, trade policy, market entry, and economies of scale among producers and consumers of the core steel. The magnitudes of these potential influences on the cross-over point cannot be precisely known in advance.

DOE attempted to survey manufacturers about the mix of core steel used currently for transformers meeting various efficiency levels and also queried the industry about their expectations for core steel mix at those efficiencies should the next DOE standard require them. However, beyond those presentations made publicly by various manufacturers during the negotiations—which demonstrated conflicting views on the ''crossover point''—DOE could not gather sufficient data to calculate manufacturer expectations of the crossover point at various TSLs. While several stakeholders have pointed to the ''tipping point'' shown by the LCC's steel selection analysis as evidence that the market will transition to amorphous entirely for some design lines, DOE repeats here that not every possible design was analyzed and that the LCC tool is highly sensitive to price assumptions which have been shown to be extremely variable over time and among suppliers. Balancing all of the evidence in this docket, DOE believes that the levels established by today's final rule will maintain a choice of steel mix for the industry. As discussed in the weighing of benefits and burdens section (section IV.I.5.d), DOE remains concerned about the potential for significant disruption in the steel supply market at levels higher than those established by today's rule.

As for the conversion costs that may be required should some manufacturers decide to begin making, or to increase production of, amorphous core transformers, DOE accounts for them in the GRIM analysis.

Supply and Capacity. The ability of core steel producers to increase supply if necessary is another related key issue discussed by stakeholders. Some stakeholders were concerned that suppliers may not have the capacity to produce certain steels in quantities great enough to meet demand at higher efficiency levels, while other stakeholders believed that suppliers will be fully capable of expanding capacity as needed.

Several stakeholders expressed concerns about utilities being unable to serve customers due to steel supply constraints in the distribution chain. EEI stated that its members do not want to repeat the situation they faced in 2006–2008 when there were transformer shortages and utilities were told that there would be delays of months or even years before certain transformers would be available. (EEI, No. 185 at p. 10) APPA noted that the threat of transformer rationing may return in an improved economy and hamper the ability of utilities to meet their obligation to serve customers. (APPA, No. 191 at p. 10) Likewise, Consolidated Edison believes that the possible requirement to use higher grade core steels in order to achieve higher efficiencies may result in supply scarcity, increased costs, and tough competition for these materials after recovery from the global recession. (ConEd, No. 236 at p. 4) Commonwealth Edison Company is very concerned about the availability of a quality steel supply for the transformer manufacturing industry and that a limited supply of transformers will have a significant negative effect on the company's ability to provide safe and reliable electric service to its customers. (ComEd, No. 184 at p. 11) Howard Industries is also concerned about the limited availability of critical core materials such as M2 and amorphous, which could pose a large risk to the transformer and utility industries and may become a particularly troublesome issue if the economy and housing markets return to more normal levels. (Howard Industries, No. 226 at p. 2) In addition, the USW stated that the number of transformer producers with the equipment to build reliable transformers with amorphous ribbon cores is relatively small. Therefore, a sudden transition to amorphous ribbon would result in a fragile supply chain for distribution transformers, potentially leading to large cost increases and supply shortages that would place the security of the U.S. electrical transmission grid at risk. (USW, No. 148 at p. 2) ATI stated during the NOPR public meeting that a scenario in which grain-oriented electrical steel is not available as a core material option could result in a long-term situation where no domestic companies would produce the strategically important material for transformers that are the critical link in the U.S. electrical grid. (ATI, No. 146 at p. 19)

Some stakeholders also emphasized the importance of being able to use M3 steel, which is more readily available than other more efficient steels. Prolec-GE noted that silicon steel grades above M3 have significant supply limitations and predicted no change in that situation for the foreseeable future. Therefore, Prolec-GE continues to see the need for a balanced approach to higher efficiencies such that M3 silicon steel and amorphous metal can compete for a share of the liquid-immersed market, which would allow manufacturers to have a sufficient supply of these materials to serve customer requirements. (Prolec-GE, No. 52 at pp. 11–12) Progress Energy also stated that M2 core steel is in short supply because it is only a small part of a silicon core steel producer's output and M3 and M4 grades of core steel should be required for 85 percent or more of any required efficiency level so that utilities will not face shortage situations that would have negative impacts on grid reliability. (Progress Energy, No. 192 at pp. 7–8) Likewise, Power Partners voiced concern about the U.S. supply of core steel should DOE adopt an efficiency that requires the use of grades better than M3. Power Partners stated that the current domestic capacity for M2 will not support 100 percent of all liquid-immersed transformers and, therefore, recommended that DOE only consider efficiency levels that can be attained with M3 core steel with no loss evaluation. The grades better than M3 should be employed when the utility loss evaluation justifies its use. (Power Partners, No. 155 at pp. 3–4) Southern California Edison has stated that greater market demand for M2 core steel may create supply shortages and result in high steel prices. (Southern California Edison, No. 239 at p. 1) According to Central Moloney, M2 and higher grades of steel are premium products within the steel manufacturing process which comprise no more than 15 percent of overall steel production. Central Moloney is concerned that the marketplace will not be able to support the demand of these premium products if efficiency levels are increased. (Central Moloney, No. 224 at pp. 1–2)

Stakeholders have also expressed several concerns regarding the availability of steels supplied by foreign vendors, especially amorphous steel. Both Commonwealth Edison Company and Baltimore Gas and Electric Company stated that the overseas procurement of steel could result in specification issues and that there could be a negative impact on the U.S. electric grid if DOE sets a standard that requires the use of a specific core steel that is not readily available in the domestic market and which does not have a proven track record. (ComEd, No. 184 at p. 12 and BG&E, No. 182 at p. 7) Power Partners has stated that grades of grain-oriented electrical steel better than M2 for wound core applications are only available from international sources and supply capacity is very limited. (Power Partners, No. 155 at pp. 3–4) In addition, Progress Energy is concerned that amorphous and mechanically scribed core steel will not be available in sufficient quantities because domestic transformer vendors rely on basically one amorphous core steel provider. This supplier may not have the capacity to provide enough amorphous material to meet demand from all U.S. transformer manufacturers as well as overseas business if the efficiency levels are increased beyond EL 1 for liquid-immersed distribution transformers. (Progress Energy, No. 192 at pp. 7–8) ABB has indicated that amorphous steel is a sole source product for the U.S., and, as demand increases for it, there could be a tight global supply as well as upward price pressure. (ABB, No. 158 at p. 8) ABB has also expressed concerns about mechanically scribed steel. This type of steel has only four global suppliers, and its availability may be subject to international trade restrictions. (ABB, No. 158 at p. 8) According to Cooper Power Systems, ZDMH is in large part unavailable in the U.S. and should therefore represent only a small fixed percentage of overall usage. (Cooper Power Systems, No. 222 at p. 2)

However, some stakeholders are more confident that the supply of higher efficiency steels would increase to meet demand due to higher standards. ACEEE, ASAP, NRDC, and NPCC believe that it is highly unlikely that amorphous production will not expand in response to higher standards because: (1) The U.S. producer of amorphous metal has demonstrated its ability to add capacity over the past several years as producers of high-value electricity (e.g., wind producers) have favored amorphous metal products, and (2) other manufacturers are exploring amorphous production and there are no legal barriers to entry for new competitors. (Advocates, No. 186 at p. 11) The Advocates also noted that one of the largest global suppliers of silicon steel for transformers, POSCO (formerly Pohang Iron and Steel Company), is entering the amorphous metal market. The company approved a plan for commercializing amorphous metal production in 2010 and will soon begin production and marketing of amorphous metal with plans to produce up to 1 kiloton (kt) in 2012, 5 kt in 2013, and 10 kt in 2014. (Advocates, No. 235 at p. 3) Schneider Electric stated that, with the exception of amorphous, there are sufficient suppliers worldwide (Europe and Asia) who have either increased capacity or who have near term plans to increase capacity to meet the growing demand for high-grade steels. The company feels it is better to allow global market conditions to dictate business plans rather than the DOE because manufacturing and freight costs play a lesser role than supply and demand in determining the final price for high-grade steels, whether domestic or foreign, as long as there are sufficient suppliers worldwide. (Schneider, No. 180 at p. 6) In addition, Hydro-Quebec has stated that the equipment for making amorphous steels is mainly used to serve the distribution transformer market, which allows amorphous steel to be less influenced by other non-transformer markets that may impact steel price and availability. Amorphous steel production lines are also much smaller than silicon steel lines, thereby allowing amorphous steel makers to add production capacity by small increments with relatively low capital expenditures and in a relatively short time frame. Hydro-Quebec therefore believes that amorphous steel production can be tightly connected with increasing demand. (Hydro-Quebec, No. 125 at p. 2) Metglas, has also stated that an increase in capacity to even 100 percent of 2016 demand would only require an approximately $200M investment in amorphous metal casting capacity and an even smaller total industry investment by core/transformer makers in amorphous metal transformer manufacturing capacity. Metglas further stated that it has a technology transfer program to assist any U.S. transformer maker in quickly progressing into production of amorphous metal-based transformers. (Metglas, No. 102 at p. 2) Berman Economics supports Metglas' position, arguing that Metglas has demonstrated its willingness and capability to increase capacity as a result of the 2007 Final Rule and should be expected to do so again, particularly considering the financial resources available to Metglas from its parent, Hitachi. Moreover, since there are no patent restrictions on amorphous steel, there is nothing to prevent silicon steel from diversifying to include an amorphous line should it choose to do so. (Berman Economics, No. 150 at p. 10) Berman Economics also believes that DOE improperly assumes that increased use of amorphous will reduce silicon steel production in an effort to ensure that silicon steel production does not suffer profit losses as amorphous becomes more competitive. Additionally, Earthjustice claimed that DOE did not rationally analyze the potential impacts associated with steel production capacity constraints because, according to the NOPR, adopting TSLs 2 or 3 for liquid-immersed transformers would lead to shortages of amorphous metal such that grain-oriented electrical steel cores would have to be used in non-cost-effective applications, but in the TSD, those TSLs would split the market between amorphous and grain-oriented steels and DOE expects minimal core steel capacity issues at TSLs that do not force the entire market into amorphous steel usage. (Earthjustice, No. 195 at pp. 1–2)

DOE is aware that there is currently only one global supplier of amorphous steel with any significant capacity and that the parent company is foreign-owned (although a substantial share of its production takes place domestically through its U.S. subsidiary). At the same time, a few other steel producers have announced plans to begin, or have recently begun, very limited production of amorphous metal. DOE is also aware that there are only a few suppliers for mechanically scribed steel and that some of these suppliers are also foreign-owned. Given the lack of suppliers of domain-refined (e.g., H0, ZDMH) and amorphous steels, DOE agrees that the amended energy conservation standards should provide manufacturers with the option to cost-effectively use grain-oriented silicon steels, which have fewer supply constraints. This would help ensure that utilities have access to transformers, particularly in the event of stronger economic growth (a driver of transformer demand) or a natural disaster, both concerns raised by commenters. Furthermore, DOE understands that M2 cannot be produced at the quantities equivalent to current M3 yields due to the nature of the silicon steel production process. Given these facts, DOE concluded that a standard that could not be achieved by M3 would not be economically justified. On the other hand, DOE also acknowledges that the current amorphous supplier may be able to expand capacity to meet additional demand and a few other companies have begun the initial stages of developing capacity. The eventual steel quality and production capacity of these emerging amorphous sources are unknown at this time. Therefore, DOE has been careful in selecting a TSL that would allow manufacturers to use not only amorphous and mechanically scribed steel,that is currently produced in limited quantities, but also grain-oriented steels.

DOE believes that the Earthjustice comment that DOE did not rationally analyze the potential impacts associated with steel production capacity constraints actually refers to two related but separate issues in the NOPR and NOPR TSD. In the TSD, DOE explains that the availability of total core steel would not be an issue until TSL 4 because both conventional and amorphous steels would be available to use until that point. In the NOPR, DOE explains that the availability of amorphous steel may be an issue at TSLs 2 and 3, and that manufacturers may need to use other types of steels, such as M3, which are not the lowest cost options. These statements are not contradictory because, although amorphous steel capacity may not be able to expand to meet all demand at TSLs 2 and 3, that does not imply that total core steel capacity would be insufficient because manufacturers still have the option of using M3 or M2 or other steels at these levels.

b. Small Manufacturers

An important area of discussion among stakeholders is the impact of energy efficiency standards on small manufacturers. At the NOPR public meeting, ASAP had suggested that DOE should do additional work to better document and understand the scale of the impacts on small manufacturers. (ASAP, No. 146 at p. 170)

Some stakeholders expressed concern that standards higher than those proposed in the NOPR would have a significant negative impact on small manufacturers. NEMA is very concerned with the possibility that higher efficiency standards will negatively impact small manufacturing facilities and may drive some small companies, in particular LVDT transformer manufacturers, out of business. (NEMA, No. 170 at pp. 4, 8) In addition, at least one small NEMA manufacturer of liquid-immersed distribution transformers has reported that it cannot stay in business at levels higher than EL1. (NEMA, No. 170 at p. 6) APPA is also concerned about small manufacturer impacts resulting from the use of amorphous steel, stating that small transformer manufacturers that may not be able to afford or have the expertise to convert their plants to accommodate amorphous core construction may be forced to go out of business. (APPA, No. 191 at p. 5) HVOLT commented that producing stacked core products with mitering would take millions of dollars and small manufacturers in some states cannot afford that investment, and may be forced to go out of business. (HVOLT, No. 146 at pp. 50–51) Furthermore, at higher efficiency levels, even if small manufacturers can continue to use butt-lapping, they may not be able to sell their transformers at a price where material costs are recovered. (HVOLT, No. 146 at p. 151)

However, other stakeholders have suggested that small manufacturer effects have been overemphasized in DOE's analysis. ACEEE, ASAP, NRDC, and NPCC disagreed with DOE's small business analysis, claiming that it overstates impacts on small business manufacturers of LVDT transformers. The NOPR record and an investigation by the Advocates indicate that the vast majority of covered transformers are manufactured by a handful of large manufacturers with all of their major production facilities in Mexico. Since small, domestic manufacturers cannot compete on price with Mexican production facilities, domestic manufacturers focus on specialty transformers which are generally outside the scope of the regulation or on high-efficiency offerings. (Advocates, No. 186 at pp. 5–6) Furthermore, even if DOE finds that there are a significant number of small manufacturers with U.S. production facilities making covered LVDT transformers, the Advocates suggest that DOE should still adopt TSL 3 because any small manufacturer with long term viability in the distribution transformer market can build compliant transformers. DOE's record indicates that the least-cost option for building LVDT transformers at TSL 3 entails step-lap mitering and some small manufacturers already have mitering equipment. The Advocates commented that for companies that currently lack mitering machines, industry experts have testified that a step lap mitering machine costs between $0.5 million and $1 million, which is a small investment that should be well within reach for viable manufacturing companies, even if they are small. The Advocates also indicate that DOE may have placed too much emphasis on small business impacts in its decision-making criteria. Companies also have the option of sourcing their cores from third party suppliers, who can obtain better materials prices than all but the largest transformer makers, regardless of the efficiency levels chosen. In fact, they cite to the NOPR to support the notion that market pressures are already likely to be pushing small transformer manufacturers to purchase sourced cores regardless of the efficiency levels adopted. (Advocates, No. 186 at p. 6) Furthermore, although small manufacturers may not get the same treatment from steel suppliers as large manufacturers do, small manufacturers will face this disadvantage regardless of the standard level chosen. (Advocates, No. 186 at p. 5)

Similar sentiments were expressed by California Investor Owned Utilities (CA IOUs). According to the CA IOUs, although DOE repeatedly emphasizes the concern that small manufacturers may be disproportionately impacted by higher standard levels and leans on this concern as justification for selecting TSL 1 for low-voltage dry-type transformers, there are actually very few small manufacturers in this market and those small manufacturers that do exist primarily focus on design lines that are exempted from coverage. The CA IOUs commented that some small manufacturers that do produce covered transformers are focusing on high efficiency NEMA Premium® transformers, indicating that smaller manufacturers are already capable of producing higher efficiency transformers. Furthermore, small manufacturers could source their cores, and many are currently doing so today, which offsets any need to upgrade core construction equipment. (CA IOUs, No. 189 at pp. 2–3)

Also, Earthjustice has commented that DOE has arbitrarily relied on impacts on small manufacturers in rejecting stronger standards for low-voltage dry-type (LVDT) units despite there being few, if any, small manufacturers of this equipment who are likely to be impacted. DOE has not explained why sourcing cores is not an acceptable option for any small manufacturer and, given the evidence in the TSD that sourcing cores is a more profitable approach for small manufacturers of LVDTs, DOE's reliance on the adverse financial impacts to small manufacturers associated with producing such cores in-house in rejecting stronger LVDT standards is unreasonable. (Earthjustice, No. 195 at pp. 3–5)

NEEP has suggested that DOE should not sacrifice large national benefits to provide ill-defined benefits for a small number of manufacturers. Even if some domestic small manufacturers may be affected by the new standards, DOE should do a more comprehensive analysis of how much the standards would impact those small manufacturers. The investments needed to meet new standards may be affordable for companies which have covered transformers as a significant part of their business, and companies that have covered transformers as a small portion of their business may choose to exit this part of the market or source their cores. (NEEP, No. 193 at pp. 4–5)

DOE understands that small companies face additional challenges from an increase in standards because they are more likely to have lower production volumes, fewer engineering resources, a lack of purchasing power for high performance steels, and less access to capital.

For liquid-immersed distribution transformers, DOE does not believe that small manufacturers will face significant capital conversion costs at TSL 1 because they can continue to produce silicon steel cores using M3 or better grades rather than invest in amorphous technology should they make that business decision. Alternatively, they could source their cores, a common industry practice.

For the LVDT market, DOE conducted further analysis based on comments received on the NOPR to reevaluate the impact of higher standards on small manufacturers. Although there may not be many small LVDT manufacturers that produce covered equipment in the U.S. and small manufacturers may hold only a low percentage of market share, the Department of Energy does consider impacts on small manufacturers to be a significant factor in determining an appropriate standard level. As discussed in the engineering analysis, because commenters suggested that EL3, the efficiency level selected at TSL 2 for DL7 (equivalent to NEMA Premium®), could be achieved with a butt-lap design, DOE further investigated the efficiency limits of butt-lapping potential. The primary reason that DOE proposed TSL 1 over TSL 2 in the NOPR was because it did not appear that TSL 2 could be met using butt-lapping technology, which would have caused undue hardship on small manufacturers that utilize this technology. However, in response to comments from the NOPR, DOE analyzed additional design option combinations using butt-lapping technology for DL 7 in its engineering analysis and determined that EL 3 can still be achieved without the need for mitering by using higher grade steels. While these would likely not be the designs of choice for high-volume manufacturers because the capital cost of a mitering machine has a much lower per unit cost given their larger volumes, this option may allow low-volume players, such as small manufacturers, to avoid investing in mitering machines or sourcing their cores due to financial constraints. However, at TSL 3 and higher, manufacturers may not be able to continue using butt-lapping technology with steels that are readily available.

Although sourced cores may be the most cost-effective strategy in the near term, some manufacturers indicated during interviews that production of cores is an important part of the value chain and that they could ill-afford to cede it to third parties. On the other hand, some manufacturers indicated they are able to successfully compete because of their sourcing strategies, not in spite of them, because they can meet a variety of customer needs more quickly and cheaply than would otherwise be possible. Particularly because most small U.S. LVDT manufacturers are heavily involved in the transformer market not otherwise covered by statute, which constitutes roughly 50 percent of all LVDT sales, DOE believes that sourcing DOE-covered mitered cores represents a viable strategic alternative for small LVDT manufacturers, given that it is a common industry business strategy for low volume product lines.

In conclusion, DOE believes that TSL 2, the level established by today's standards, affords small LVDT transformer manufacturers with several strategic paths to compliance: (1) Investing in mitering capability, (2) continuing to use low-capital butt-lap core designs with higher grade steels, (3) sourcing cores from third-party core manufacturers, or (4) focus on the exempt portion of the market.

c. Conversion Costs

Berman Economics questioned DOE's methodology for calculating conversion costs, which was described in section IV.I.3.c of the NOPR. Berman argued that DOE provided unreasonable estimates of conversion costs because DOE based estimates on an arbitrary percent of total R&D expenditures across all equipment regulated by DOE. Therefore, the conversion cost estimates are not relevant to the proposed regulatory action. (Berman Economics, No. 150 at pp. 14–15)

In response, the percentages that DOE used to determine product conversion costs for liquid-immersed transformer manufacturers were based solely on information relevant to the distribution transformer industry, not for all equipment regulated by DOE. DOE's estimates for product conversion expenses for liquid-immersed distribution transformer manufacturers would be based upon the extent to which the industry would need to convert to amorphous technology. This methodology is similar to the one used for the 2007 final rule but modified to reflect feedback from manufacturers during interviews and to consider the technology required to meet the efficiency levels from the current rulemaking.

Berman Economics also commented that DOE's estimates of stranded assets were illogical for production, financial, and corporate strategy reasons. From a production perspective, there is likely to be a net increase in demand for silicon steel at EL 2 for liquid-immersed transformers so assets such as annealing ovens would not be stranded. Berman Economics stated most annealing ovens are very old and have already been depreciated, and manufacturing investment may be expensed in the year purchased according to current tax laws, so the cost of all recently purchased annealing ovens has already been recovered. From a strategic perspective, if a manufacturer chooses not to offer an amorphous line of products, DOE should not put itself in a position to favor that manufacturer's strategy over another. Furthermore, Berman Economics stated that DOE based stranded assets on an arbitrary percent of new capital conversion costs which may have been a holdover from the decision on microwave ovens. (Berman Economics, No. 150 at pp. 15–16)

DOE agrees that the calculations in the NOPR for stranded assets were incorrectly derived in the GRIM and has revised the model for the final rule. For the final rule, stranded assets in the standards case are derived from the share of the industry's net property, plant and equipment (PPE) that is estimated to no longer be useful due to energy conservation standards. The change has no substantial effect on the overall results. See TSD chapter 12 for more details.

Berman Economics also stated that DOE has overestimated capital conversion costs because the Department assumed a 100 percent front-load in investment prior to the 2016 effective date rather than a least-cost method of financing, such as a long-term loan. (Berman Economics, No. 150 at p. 16)

Accounting for investments in the time frame between the effective date of today's rule and the rule compliance date is the accepted methodology vetted during the preliminary analysis and the standard model used for DOE rulemakings. This methodology also considers the possibility that some manufacturers, such as small manufacturers, may have difficulty obtaining loans.

In addition, Berman Economics argued that an increased market demand for amorphous steel relative to silicon steel may reduce investment expenditures rather than increase them because the annealing oven for an amorphous steel core costs substantially less than the annealing oven for a silicon steel core. Some transformer manufacturers may also be able to source cores, which, Berman Economics stated, DOE incorrectly considered an undesirable market activity. Berman Economics noted that an outsourcing opportunity allows manufacturers to specialize, use cash for other strategic purposes, and pursue multiple objectives. (Berman Economics, No. 150 at pp. 16–17)

DOE takes into account conversion costs associated with a given TSL. While the cost of a single annealing oven for an amorphous steel core may be less than the cost of a single annealing oven for a silicon steel core, other factors, particularly throughput levels, associated tooling, and the R&D expenses allocated to the development of new designs and production processes, also drive conversion costs calculations.

With respect to core sourcing, as with the above discussion related to the LVDT market, DOE notes that it is not making any judgment on the value of one business strategy versus another. Whether sourcing cores is a viable option for any given manufacturer is a decision for each manufacturer in the context of its unique environment. However, during interviews, some manufacturers indicated that production of cores is an important part of the value chain and doubted their long-term viability should they outsource that function.

Finally, Berman Economics has noted that the logic explained by DOE that more stringent levels of efficiency are associated with larger adverse industry impacts does not hold true in the GRIM, which indicates that the model contains a multiplicity of unknown logic errors and its results must be viewed as spurious. (Berman Economics, No. 150 at p. 18)

Although higher efficiency levels are often correlated with greater adverse industry impacts, certain offsetting factors based on DOE's markup assumptions may result in deviations from this pattern. For example, in the preservation of gross margin percentage scenario, DOE applied a single uniform ''gross margin percentage'' markup across all efficiency levels so that, as production costs increase with efficiency, the absolute dollar markup increases as well. Therefore, the highest efficiency levels do not result in the highest drop in INPV because manufacturers are able to compensate for higher conversion costs by charging higher prices.

6. Manufacturer Interviews

DOE interviewed manufacturers representing approximately 65 percent of liquid-immersed distribution transformer sales, 75 percent of medium-voltage dry-type transformer sales, and 50 percent of low-voltage dry-type transformer sales. These interviews were in addition to those DOE conducted as part of the engineering analysis. DOE outlined the key issues for the rulemaking for manufacturers in the NOPR. 77 FR 7282 (February 10, 2012). DOE considered the information received during these interviews in the development of the NOPR and this final rule.

7. Sub-Group Impact Analysis

DOE identified small manufacturers as a subgroup in the MIA. DOE describes the impacts on small manufacturers in section VI.B. below.

J. Employment Impact Analysis

Employment impacts include direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the equipment subject to standards, their suppliers, and related service firms. The MIA addresses those impacts. Indirect employment impacts are changes in national employment that occur due to the shift in expenditures and capital investment caused by the purchase and operation of more efficient appliances. Indirect employment impacts from standards consist of the jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, due to: (1) Reduced spending by end users on energy; (2) reduced spending on new energy supply by the utility industry; (3) increased consumer spending on the purchase of new equipment; and (4) the effects of those three factors throughout the economy. DOE's employment impact analysis addresses these impacts. No public comments were received on this analysis.

One method for assessing the possible effects on the demand for labor of such shifts in economic activity is to compare sector employment statistics developed by the Labor Department's Bureau of Labor Statistics (BLS). BLS regularly publishes its estimates of the number of jobs per million dollars of economic activity in different sectors of the economy, as well as the jobs created elsewhere in the economy by this same economic activity. Data from BLS indicate that expenditures in the utility sector generally create fewer jobs (both directly and indirectly) than expenditures in other sectors of the economy.[56] There are many reasons for these differences, including wage differences and the fact that the utility sector is more capital-intensive and less labor-intensive than other sectors. Energy conservation standards have the effect of reducing consumer utility bills. Because reduced consumer expenditures for energy likely lead to increased expenditures in other sectors of the economy, the general effect of efficiency standards is to shift economic activity from a less labor-intensive sector (*i.e.,* the utility sector) to more labor-intensive sectors (e.g., the retail and service sectors). Thus, based on the BLS data alone, DOE believes net national employment may increase because of shifts in economic activity resulting from amended standards for transformers.

For the standard levels considered in today's final rule, DOE estimated indirect national employment impacts using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 3.1.1 (ImSET). ImSET is a special-purpose version of the ''U.S. Benchmark National Input-Output'' (I–O) model, which was designed to estimate the national employment and income effects of energy-saving technologies. The ImSET software includes a computer-based I–O model having structural coefficients that characterize economic flows among the 187 sectors. ImSET's national economic I–O structure is based on a 2002 U.S. benchmark table, specially aggregated to the 187 sectors most relevant to industrial, commercial, and residential building energy use. DOE notes that ImSET is not a general equilibrium forecasting model, and understands the uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Because ImSET does not incorporate price changes, the employment effects predicted by ImSET may over-estimate actual job impacts over the long run. For the final rule, DOE used ImSET only to estimate short-term employment impacts.

For more details on the employment impact analysis, see chapter 13 of the final rule TSD.

K. Utility Impact Analysis

The utility impact analysis estimates several important effects on the utility industry that would result from the adoption of new or amended standards. To calculate this, DOE first obtained the energy savings inputs associated with efficiency improvements to the considered products from the NIA. Then, DOE used that data in the NEMS–BT model to generate forecasts of electricity consumption, electricity generation by plant type, and electric generating capacity by plant type, that would result from each TSL. Finally, DOE calculates the utility impact analysis by comparing the results at each TSL to the latest *AEO* Reference case. For the final rule, the estimated impacts for the considered standards are the differences between values derived from NEMS–BT and the values in the *AEO 2012* reference case.

Chapter 14 of the final rule TSD describes the utility impact analysis. No public comments were received on this analysis.

L. Emissions Analysis

In the emissions analysis, DOE estimated the reduction in power sector emissions of CO_2, SO_2, NO_X, and Hg from amended energy conservation standards for distribution transformers. DOE used the NEMS–BT computer model, which is run similarly to the *AEO* NEMS, except that distribution transformers energy use is reduced by the amount of energy saved (by fuel type) due to each TSL. The inputs of national energy savings come from the NIA spreadsheet model, while the output is the forecasted physical emissions. The net benefit of each TSL is the difference between the forecasted emissions estimated by NEMS–BT at each TSL and the *AEO* Reference Case. NEMS–BT tracks CO_2 emissions using a detailed module that provides results with broad coverage of all sectors and inclusion of interactive effects. For today's rule, DOE used the version of NEMS–BT based on *AEO 2012,* which generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of December 31, 2011.

SO_2 emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap and trading programs. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (DC). SO_2 emissions from 28 eastern States and DC were also limited under the Clean Air Interstate Rule (CAIR), which created an allowance-based trading program that operates along with the Title IV program. 70 FR 25162 (May 12, 2005) CAIR was remanded to the U.S. Environmental Protection Agency (EPA) by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in 2008, but it remained in effect. On July 6, 2011 EPA issued a replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR). 76 FR 48208 (August 8, 2011). The version of NEMS–BT used for today's rule assumes the implementation of CSAPR.[57]

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

Beginning in 2015, however, SO_2 emissions will fall as a result of the Mercury and Air Toxics Standards (MATS) for power plants, which were announced by EPA on December 21, 2011. 77 FR 9304 (Feb. 16, 2012). In the final MATS rule, EPA established a standard for hydrogen chloride as a surrogate for acid gas hazardous air pollutants (HAP), and also established a standard for SO_2 (a non-HAP acid gas) as an alternative equivalent surrogate

[56] See Bureau of Economic Analysis, Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II). Washington, DC. U.S. Department of Commerce, 1992.

[57] On December 30, 2011, the D.C. Circuit stayed the new rules while a panel of judges reviews them, and told EPA to continue administering CAIR. See *EME Homer City Generation, LP* v. *EPA,* Order, No. 11–1302, Slip Op. at *2 (D.C. Cir. Dec. 30, 2011). On August 21, 2012, the D.C. Circuit vacated CSAPR. *See EME Homer City Generation, LP* v. *EPA,* No. 11–1302, 2012 WL 3570721 at *24 (D.C. Cir. Aug. 21, 2012). The court ordered EPA to continue administering CAIR. *AEO 2012* had been finalized prior to both these decisions, however. DOE understands that CAIR and CSAPR are similar with respect to their effect on emissions impacts of energy efficiency standards.

standard for acid gas HAP. The same controls are used to reduce HAP and non-HAP acid gas; thus, SO_2 emissions will be reduced as a result of the control technologies installed on coal-fired power plants to comply with the MATS requirements for acid gas. *AEO 2012* assumes that, in order to continue operating, coal plants must have either flue gas desulfurization or dry sorbent injection systems installed by 2015. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions. Under the MATS, NEMS shows a reduction in SO_2 emissions when electricity demand decreases (*e.g.,* as a result of energy efficiency standards). Emissions will be far below the cap that would be established by CSAPR, so it is unlikely that excess SO_2 emissions allowances resulting from the lower electricity demand would be needed or used to permit offsetting increases in SO_2 emissions by any regulated EGU. Therefore, DOE believes that efficiency standards will reduce SO_2 emissions in 2015 and beyond.

Under CSAPR, there is a cap on NO_X emissions in 28 eastern States and the District of Columbia. Energy conservation standards are expected to have little effect on NO_X emissions in those States covered by CSAPR because excess NO_X emissions allowances resulting from the lower electricity demand could be used to permit offsetting increases in NO_X emissions. However, standards would be expected to reduce NO_X emissions in the States not affected by the caps, so DOE estimated NO_X emissions reductions from the standards considered in today's rule for these States.

The MATS limit mercury emissions from power plants, but they do not include emissions caps and, as such, DOE's energy conservation standards would likely reduce Hg emissions. For this rulemaking, DOE estimated mercury emissions reductions using the NEMS–BT based on *AEO 2012,* which incorporates the MATS.

Chapter 15 of the final rule TSD provides further information on the emissions analysis.

M. Monetizing Carbon Dioxide and Other Emissions Impacts

As part of the development of this rule, DOE considered the estimated monetary benefits from the reduced emissions of CO_2 and NO_X that are expected to result from each of the considered TSLs. To make this calculation similar to the calculation of the NPV of customer benefit, DOE considered the reduced emissions expected to result over the lifetime of equipment shipped in the forecast period for each TSL. This section summarizes the basis for the monetary values used for CO_2 and NO_X emissions and presents the values considered in this rulemaking.

For CO_2, DOE is relying on a set of values for the social cost of carbon (SCC) that was developed by a government interagency process. A summary of the basis for those values is provided below, and a more detailed description of the methodologies used is provided as an appendix to chapter 16 of the final rule TSD.

1. Social Cost of Carbon

Under section 1(b)(6) of Executive Order 12866, 58 FR 51735 (Oct. 4, 1993), agencies must, to the extent permitted by law, ''assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.'' The purpose of the SCC estimates presented here is to allow agencies to incorporate the monetized social benefits of reducing CO_2 emissions into cost-benefit analyses of regulatory actions that have small, or ''marginal,'' impacts on cumulative global emissions. The estimates are presented with an acknowledgement of the many uncertainties involved and with a clear understanding that they should be updated over time to reflect increasing knowledge of the science and economics of climate impacts.

As part of the interagency process that developed the SCC estimates, technical experts from numerous agencies met on a regular basis to consider public comments, explore the technical literature in relevant fields, and discuss key model inputs and assumptions. The main objective of this process was to develop a range of SCC values using a defensible set of input assumptions grounded in the existing scientific and economic literatures. In this way, key uncertainties and model differences transparently and consistently inform the range of SCC estimates used in the rulemaking process.

a. Monetizing Carbon Dioxide Emissions

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon dioxide emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services. Estimates of the SCC are provided in dollars per metric ton of carbon dioxide.

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A recent report from the National Research Council [58] points out that any assessment will suffer from uncertainty, speculation, and lack of information about: (1) Future emissions of greenhouse gases; (2) the effects of past and future emissions on the climate system; (3) the impact of changes in climate on the physical and biological environment; and (4) the translation of these environmental impacts into economic damages. As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.

Despite the serious limits of both quantification and monetization, SCC estimates can be useful in estimating the social benefits of reducing carbon dioxide emissions. Consistent with the directive quoted above, the purpose of the SCC estimates presented here is to make it possible for agencies to incorporate the social benefits from reducing carbon dioxide emissions into cost-benefit analyses of regulatory actions that have small, or ''marginal,'' impacts on cumulative global emissions. Most Federal regulatory actions can be expected to have marginal impacts on global emissions.

For such policies, the agency can estimate the benefits from reduced (or costs from increased) emissions in any future year by multiplying the change in emissions in that year by the SCC value appropriate for that year. The net present value of the benefits can then be calculated by multiplying each of these future benefits by an appropriate discount factor and summing across all affected years. This approach assumes that the marginal damages from increased emissions are constant for small departures from the baseline emissions path, an approximation that is reasonable for policies that have effects on emissions that are small relative to cumulative global carbon dioxide emissions. For policies that have a large (non-marginal) impact on global cumulative emissions, there is a separate question of whether the SCC is an appropriate tool for calculating the benefits of reduced emissions. This concern is not applicable to this rulemaking, and DOE does not attempt to answer that question here.

[58] National Research Council. ''Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.'' National Academies Press: Washington, DC 2009.

It is important to emphasize that the interagency process is committed to updating these estimates as the science and economic understanding of climate change and its impacts on society improves over time. Specifically, the interagency group has set a preliminary goal of revisiting the SCC values at such time as substantially updated models become available, and to continue to support research in this area. In the meantime, the interagency group will continue to explore the issues raised by this analysis and consider public comments as part of the ongoing interagency process.

b. Social Cost of Carbon Values Used in Past Regulatory Analyses

To date, economic analyses for Federal regulations have used a wide range of values to estimate the benefits associated with reducing carbon dioxide emissions. In the model year 2011 CAFE final rule, the Department of Transportation (DOT) used both a ''domestic'' SCC value of $2 per metric ton of CO_2 and a ''global'' SCC value of $33 per metric ton of CO_2 for 2007 emission reductions (in 2007$), increasing both values at 2.4 percent per year. It also included a sensitivity analysis at $80 per metric ton of CO_2.[59] A domestic SCC value is meant to reflect the value of damages in the United States resulting from a unit change in carbon dioxide emissions, while a global SCC value is meant to reflect the value of damages worldwide.

A 2008 regulation proposed by DOT assumed a domestic SCC value of $7 per metric ton of CO_2 (in 2006$, with a range of $0 to $14 for sensitivity analysis) for 2011 emission reductions, also increasing at 2.4 percent per year.[60] A regulation for packaged terminal air conditioners and packaged terminal heat pumps finalized by DOE in October of 2008 used a domestic SCC range of $0 to $20 per metric ton CO_2 for 2007 emission reductions (in 2007$). 73 FR 58772, 58814 (Oct. 7, 2008). In addition, EPA's 2008 Advance Notice of Proposed Rulemaking on Regulating Greenhouse Gas Emissions Under the Clean Air Act identified what it described as ''very preliminary'' SCC estimates subject to revision. 73 FR 44354 (July 30, 2008). EPA's global mean values were $68 and $40 per metric ton CO_2 for discount rates of approximately 2 percent and 3 percent, respectively (in 2006$ for 2007 emissions).

In 2009, an interagency process was initiated to offer a preliminary assessment of how best to quantify the benefits from reducing carbon dioxide emissions. To ensure consistency in how benefits are evaluated across agencies, the Administration sought to develop a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions. The interagency group did not undertake any original analysis. Instead, it combined SCC estimates from the existing literature to use as interim values until a more comprehensive analysis could be conducted. The outcome of the preliminary assessment by the interagency group was a set of five interim values: Global SCC estimates for 2007 (in 2006$) of $55, $33, $19, $10, and $5 per ton of CO_2. These interim values represent the first sustained interagency effort within the U.S. government to develop an SCC for use in regulatory analysis. The results of this preliminary effort were presented in several proposed and final rules and were offered for public comment in connection with proposed rules, including the joint EPA–DOT fuel economy and CO_2 tailpipe emission proposed rules.

c. Current Approach and Key Assumptions

Since the release of the interim values, the interagency group reconvened on a regular basis to generate improved SCC estimates, which were considered for this proposed rule. Specifically, the group considered public comments and further explored the technical literature in relevant fields. The interagency group relied on three integrated assessment models (IAMs) commonly used to estimate the SCC: The FUND, DICE, and PAGE models.[61] These models are frequently cited in the peer-reviewed literature and were used in the last assessment of the Intergovernmental Panel on Climate Change. Each model was given equal weight in the SCC values that were developed.

Each model takes a slightly different approach to model how changes in emissions result in changes in economic damages. A key objective of the interagency process was to enable a consistent exploration of the three models while respecting the different approaches to quantifying damages taken by the key modelers in the field. An extensive review of the literature was conducted to select four sets of input parameters for these models: Climate sensitivity, socio-economic and emissions trajectories, and discount rates. A probability distribution for climate sensitivity was specified as an input into all three models. In addition, the interagency group used a range of scenarios for the socio-economic parameters and a range of values for the discount rate. All other model features were left unchanged, relying on the model developers' best estimates and judgments.

The interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models, at discount rates of 2.5 percent, 3 percent, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3-percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. For emissions (or emission reductions) that occur in later years, these values grow over time, as depicted in Table IV.9. Additionally, the interagency group determined that a range of values from 7 percent to 23 percent should be used to adjust the global SCC to calculate domestic effects,[62] although preference is given to consideration of the global benefits of reducing CO_2 emissions.

[59] See Average Fuel Economy Standards Passenger Cars and Light Trucks Model Year 2011, 74 FR 14196 (March 30, 2009) (final rule); Final Environmental Impact Statement Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015 at 3–90 (Oct. 2008) (Available at: *http://www.nhtsa.gov/fuel-economy*).

[60] See Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015, 73 FR 24352 (May 2, 2008) (proposed rule); Draft Environmental Impact Statement Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011–2015 at 3–58 (June 2008) (Available at: *http://www.nhtsa.gov/fuel-economy*).

[61] The models are described in appendix 15–A of the final rule TSD.

[62] It is recognized that this calculation for domestic values is approximate, provisional, and highly speculative.

TABLE IV.9—SOCIAL COST OF CO_2, 2010–2050
[in 2007 dollars per metric ton]

Year	Discount Rate			
	5%	3%	2.5%	3%
	Average	Average	Average	95th Percentile
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

It is important to recognize that a number of key uncertainties remain, and that current SCC estimates should be treated as provisional and revisable since they will evolve with improved scientific and economic understanding. The interagency group also recognizes that the existing models are imperfect and incomplete. The National Research Council report mentioned above points out that there is tension between the goal of producing quantified estimates of the economic damages from an incremental metric ton of carbon and the limits of existing efforts to model these effects. There are a number of concerns and problems that should be addressed by the research community, including research programs housed in many of the agencies participating in the interagency process to estimate the SCC.

DOE recognizes the uncertainties embedded in the estimates of the SCC used for cost-benefit analyses. As such, DOE and others in the U.S. Government intend to periodically review and reconsider those estimates to reflect increasing knowledge of the science and economics of climate impacts, as well as improvements in modeling. In this context, statements recognizing the limitations of the analysis and calling for further research take on exceptional significance.

In summary, in considering the potential global benefits resulting from reduced CO_2 emissions, DOE used the most recent values identified by the interagency process, adjusted to 2011$ using the GDP price deflator. For each of the four cases specified, the values used for emissions in 2011 were $4.9, $22.3, $36.5, and $67.6 per metric ton avoided (values expressed in 2011$).[63] To monetize the CO_2 emissions reductions expected to result from amended standards for distribution transformers, DOE used the values identified in Table A1 of the ''Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,'' which is reprinted in appendix 16–A of the final rule TSD, appropriately escalated to 2011$. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain each SCC value.

2. Valuation of Other Emissions Reductions

As noted above, new or amended energy conservation standards would reduce NO_X emissions in those 22 States that are not affected by the CAIR. DOE estimated the monetized value of NO_X emissions reductions resulting from each of the TSLs considered for today's rule using a range of dollar per ton values cited by OMB.[64] These values, which range from $370 per ton to $3,800 per ton of NO_X from stationary sources, measured in 2001$ (equivalent to a range of $450 to $4,623 per ton in 2011$), are based on estimates of the mortality-based benefits of NO_X reductions from stationary sources made by EPA. In accordance with OMB guidance, DOE conducted two calculations of the monetary benefits derived using each of the above values for NO_X, one using a discount rate of 3 percent and the other using a discount rate of 7 percent.[65]

Commenting on the NOPR, APPA stated that DOE has significantly overstated the environmental benefits from NO_X reduction attributed to the efficiency levels in the proposed rule. APPA suggested that DOE use emissions allowance prices from EPA's Clean Air Interstate Rule and the NO_X Budget Trading Program, which averaged $15.89 per ton in 2011. (APPA, No. 191 at p. 2)

In response, DOE disagrees with APPA's claim that ''[t]hese emissions markets and their subsequent prices were designed to monetize the environmental cost of polluting in its entirety.'' Emissions allowance prices in any given market are a function of several factors, including the stringency of the regulations and the costs of complying with regulations, as well as the initial allocation of allowances. The prices do not reflect the potential damages caused by emissions that still take place. There is extensive literature on valuation of benefits of reducing air pollutants, including valuation of reduced NO_X emissions from electricity generation.[66] The values that DOE has used are consistent with the estimates in the literature.

DOE has decided to await further guidance regarding consistent valuation and reporting of Hg emissions before it monetizes Hg in its rulemakings.

N. Labeling Requirements

In the NOPR, DOE responded to comments regarding the classification and labeling of rectifier and testing transformers. In response to these comments, DOE acknowledged that the proposed additions to the definitions helped to clarify ''rectifier'' and ''testing transformers'' and proposed to amend the definitions accordingly.

[63] Table A1 presents SCC values through 2050. For DOE's calculation, it derived values after 2050 using the 3-percent per year escalation rate used by the interagency group.

[64] U.S. Office of Management and Budget, Office of Information and Regulatory Affairs, 2006 Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities, Washington, DC Page 64.

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

[66] *See* e.g., Burtraw, Dallas, Karen Palmer, Ranjit Bharvirkar, and Anthony Paul (2001). Cost-Effective Reduction of NO_X Emissions from Electricity Generation. Discussion Paper 00–55REV. Resources for the Future, Washington, DC.

Cooper Power expressed support for the plan DOE set forth in the NOPR to clarify rectifier and testing transformers. (Cooper, No. 165 at p. 2) Howard Industries also expressed support, noting that while they do not manufacture rectifier or testing transformers, they find DOE's nameplate request to ''indicate that they are for such purposes exclusively'' to be acceptable. (HI, No. 151 at p. 12) Earthjustice commented that the addition of labeling requirements for rectifier and testing transformers can help prevent misapplication of these exempt products, but they feel additional changes, such as requiring any print or electronic marketing for such units to indicate their use specifically, may also be necessary to ensure enforcement. (Earthjustice, No. 195 at p. 5; Earthjustice No. 146 at p. 44) However, Progress Energy commented that rectifier and testing transformers are already very specialized and usually more expensive than distribution transformers; therefore, there is a very low chance of a utility attempting to replace a distribution transformer with one of these transformers. (PE, No. 192 at p. 4) APPA concurred, noting that they were unaware of rectifier or testing transformers being used as a loophole. (APPA, No. 191 at p. 6) Similarly, HVOLT pointed out that the physical differences between rectifier and distribution transformers would be fairly obvious without a nameplate marking. Furthermore, they feel that adding the word ''rectifier'' to the nameplate would only add more congestion. (HVOLT, No. 146 at p. 46)

In response to the NOPR, many stakeholders expressed their support for clearly identifying transformers excluded from DOE standards through a standardized labeling system. ABB recommended that the text ''DOE Excluded: Transformer type'' be included on the nameplate for all of the excluded type transformers, and suggested that this labeling requirement be added to CFR part 429. (ABB, No. 158 at p. 5) ABB also noted that they agree with the proposal to not set standards for step-up transformers, and that all step-up transformers be identified on the nameplate with uniform language. (ABB, No. 158 at p. 6) NEMA agreed with ABB, stating that ''labeling should be applied in a consistent manner for all designated non-regulated distribution transformers'' and suggested the following language be used: ''This _____Transformer is NOT intended for use as a Distribution Transformer per 10 CFR 431.192'' (NEMA, No. 170 at p. 7) Prolec-GE and PEMCO expressed similar ideas, both commenting that all excluded transformers should be identified by type and indicate that they are excluded from standards. (PEMCO, No. 183 at p. 2; Prolec-GE, No. 177 at p. 7) Schneider concurred, stating ''all non-regulated transformers should require labeling—not just rectifier and testing transformers.'' (Schneider, No. 180 at p.3)

Prolec-GE encouraged DOE to establish labeling requirements or guidelines for covered products for use in the United States. They believed that, at present, without specifications for labeling products, those charged with certification, compliance and enforcement would have difficulty identifying which products were to meet which standards a difficult time with inconsistent labeling. (Prolec-GE, No. 177 at pp. 16–17) Schneider Electric also expressed that regulated products should have labeling rules with the following language ''DOE 10 CFR PART 431 COMPLIANT.'' Schneider would also like DOE certification regulations (10 CFR part 429) expanded to include non-regulated products. (Schneider, No. 180 at p. 3)

GE commented that refurbished units should be labeled as such and have the original manufacturer's nameplate removed. (GE, No. 146 at p. 114)

DOE had initially considered amending the definitions of ''rectifier transformer'' and ''testing transformer'' to include a labeling requirement. Commenters, however, have pointed out that a number of transformer types would benefit from a clear set of labeling requirements, which could aid manufacturers, consumers, and DOE itself in determining whether a given sample is covered or determined by the manufacturer as meeting the standards. Given the breadth of the issue, DOE makes no changes to labeling requirements in today's rule, but may address the matter of distribution transformer labeling in a future rulemaking. DOE appreciates the comments and feedback regarding labeling supplied by the stakeholders. Issues regarding labeling, compliance, and enforcement may, however, be considered in a different proceeding.

O. Discussion of Other Comments

Comments DOE received in response to the NOPR analysis on the soundness and validity of the methodologies and data DOE used are discussed in previous parts of section IV. Other stakeholder comments in response to the NOPR addressed specific issues associated with amended standards for transformers. DOE addresses these other comments below.

1. Supplementary Trial Standard Levels

DOE created TSLs that each consist of specific efficiency levels for a set of design lines. For the NOPR, DOE examined seven TSLs for liquid-immersed distribution transformers, six TSLs for low-voltage dry-type distribution transformers, and five TSLs for medium-voltage dry-type distribution transformers.

For liquid-immersed distribution transformers, joint comments submitted by ASAP, ACEEE, NRDC and NPCC recommended that DOE modify TSL 4 to represent their collective final position from the Negotiated Rulemaking, which advocated including EL 2 for all liquid-immersed distribution transformer design lines. (In the NOPR, DOE misstated and analyzed the Advocates collective final position from the Negotiated Rulemaking as EL3 for all liquid-immersed distribution transformer design lines.). They also recommended that DOE examine a TSL 3.5 level, which would correspond to EL 1.5 across the board. (ASAP, ACEEE, NRDC, NPCC, No. 186 at p. 9)

In response to these comments DOE considered four new TSLs, labeled A, B, C and D, to explore possible energy savings below EL 2. TSL C, consisting of EL 2 for all liquid-immersed distribution transformer design lines, correctly represents the collective final position of ASAP, ACEEE, NRDC, and NPCC in the negotiations. DOE presented these new TSLs to stakeholders at a public meeting on June 20, 2012.

Several parties stated that these new TSLs, while being technologically feasible, would present issues due to increased transformer size and weight. NRECA, Howard Industries, and NEMA stated that this issue would increase the frequency of pole replacement by utilities. (NRECA, No. 228 at p. 2; HI, No. 218 at p.1; NEMA, No. 225 at p. 6) Central Maloney commented that their designs at the new TSLs exceeded customer weight specifications for their single-phase, pole-mounted distribution transformers at various kVA capacities. (CM, No. 224 at p.3) Others stated that the economic benefits of TSLs B through D could only be realized with core steels other than M3 (NEMA, No. 225 at pp. 4, 5; ATI No. 218 at p. 1), which could transfer significant market power to producers of SA1 core steel (AK, No. 230 at p. 4) and lead to unintended anti-competitive results. (ATI, No. 218 at p. 1; AK, No. 230 at p. 5)

DOE concluded that all of these new TSLs would result in similar burdens as the TSLs 2, and 3 that were analyzed in the NOPR. As discussed further in section 5.C.1 of this final rule, all of these TSLs would face issues regarding the type of steel used in liquid-immersed transformers. DOE is concerned that the current supplier of amorphous steel, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that might be needed by transformer manufacturers before 2015. Although the industry can manufacture liquid-immersed distribution transformers at TSL 3 from M3 or lower grade steels, the positive LCC and national impacts results are based on lowest first-cost designs, which include amorphous steel for all the design lines analyzed. If manufacturers were to meet standards at TSL 3 using M3 or lower grade steels, DOE's analysis shows that the LCC impacts are negative. Given that the recommended TSLs face similar issues as TSL 3, DOE did not incorporate them into the final rule.

2. Efficiency Levels

ASAP, ACEEE, NRDC and NPCC stated that DOE has not evaluated the potential impacts of the proposed standards for liquid-immersed distribution transformers since the proposed standard levels are not the same as the levels in TSL 1 for equipment class 1. They said that DOE's final standard must be based on analysis and results for the actual efficiency levels established by the final rule. (ASAP, ACEEE, NRDC, NPCC, No. 186 at p. 9) Similarly, NEEP stated that the proposed TSL 1 for liquid-immersed distribution transformers did not have all the corresponding ELs for the various design lines. It noted that DOE proposed 98.95 percent for design line 2, which does not correspond to any EL. (NEEP, No. 193 at p. 2)

In response to these comments, for this final rule, DOE analyzed the actual efficiency ratings proposed in the NOPR for equipment class 1 (single-phase liquid-immersed transformers) at TSL 1. These efficiencies are 99.11 percent for design line 1, 98.95 percent for design line 2, and 99.49 percent for design line 3. These efficiencies correspond to EL 0.4 for design line 1, EL 0.5 for design line 2, and EL 1.1 for design line 3.

The TSLs that DOE used for the final rule are presented in section V.A of this preamble. DOE notes that, for the final rule, it has slightly modified the definition of TSL 2 for low-voltage dry-type distribution transformers from the NOPR definition. Where previously DL 6 had been at EL 3 in TSL 2, in today's rule DL 6 is held at the baseline because DOE did not find positive economic benefits to the consumer above that level. Small, single-phase transformers tend to be lightly-loaded and have a more difficult time than their larger, three-phase counterparts recovering increases in first cost. DOE believes this change provides increased customer benefits with TSL 2.

3. Impact of Standards on Transformer Refurbishment

A number of parties expressed concern that amended standards on transformers would induce use of rebuilt or refurbished distribution transformers rather than the more expensive new transformers. (HI, No.151 at pp. 9, 12; Cooper, No. 165 at p. 5; Prolec-GE, No. 177 at p. 14; ComEd, No. 184 at p. 13; Westar, No. 169 at p. 3) Several parties stated that the higher the initial cost increase due to energy efficiency standards, the higher the likelihood that utilities will use more recycled equipment. (EEI, No. 185 at p. 17; APPA, No. 191 at p. 12; Progress Energy, No. 192 at p. 9) BG&E stated that if new transformer requirements significantly increase costs, it may consider purchasing refurbished designs to address the size and weight problems of transformers meeting the standard. (BG&E, No. 182 at p. 9) Fort Collins Utilities commented that it would be purchasing fewer new transformers and re-winding more of its existing transformer units. (CFCU, No. 190 at p. 3)

Some parties specifically stated that setting standards for liquid-immersed distribution transformers greater than TSL 1 would increase the use of less-efficient, refurbished transformers, and this would reduce the energy savings from such standards. (NEMA, No. 170 at p. 3; USW, No. 188 at pp. 4, 18–19) AEC and NRECA stated that if DOE raises standards above the levels proposed in the NOPR, it is likely that costs will increase dramatically, increasing the likelihood that more existing transformers will be recycled via refurbishment, rewinding, or rebuilding. (AEC, No. 163 at p. 3; NRECA, No. 172 at p. 3)

Several parties stated that rebuilt or refurbished transformers would be less efficient than new transformers and, therefore, the energy saving goals of standards would be undermined. (HI, No. 151 at pp. 9, 12; Cooper, No. 165 at p. 5; Prolec-GE, No. 177 at p. 14) AEC and NRECA stated that, in some cases, the efficiency of transformers may actually increase as a result of refurbishment or rewinding, but the efficiency of the refurbished transformer will most likely not meet the proposed efficiency levels. (AEC, No. 163 at p. 3; NRECA, No. 172 at p. 3) HI requested that DOE seek authority over the refurbished/repair industry to minimize use of lower-efficiency transformers. (HI, No. 151 at p. 11)

DOE acknowledges that a significant increase in the cost of new transformers could encourage growth in the use of refurbished transformers by some utilities, and that refurbished transformers likely would be less efficient than new transformers meeting today's standards. Although DOE was not able to explicitly model the likely extent of refurbishing at each considered TSL, it did include in its shipments analysis a price elasticity parameter that captures the response of the market to higher costs in a general way (see chapter 9 of the final rule TSD). Furthermore, DOE believes that the costs of new transformers meeting today's standards, which are approximately 3.0 percent (design line 2) and 13.1 percent (design line 3) higher than today's typical single-phase liquid-immersed distribution transformers, and approximately 6.9 percent (design line 4) and 12.6 percent (design line 5) higher than today's typical three-phase liquid-immersed transformers, would not be so high as to induce a significant level of refurbishing instead of replacement.

Earthjustice asserted that ''the statute leaves room for DOE to regulate the efficiency of rebuilt transformers'' and that ''it is reasonable for DOE to determine that rewound transformers are 'new covered products' subject to energy conservation standards if the title of the rewound transformer is then transferred to an end-user.'' (Earthjustice No. 195 at p. 6) Other commenters reached opposite conclusions regarding whether DOE has the authority to regulate refurbished or rewound transformers. AEC agreed with statements made by DOE's Office of the General Counsel during negotiations that existing and recycled transformers are not ''covered'' equipment and would not have to meet the proposed energy efficiency standards for new products that are ''covered.'' (AEC No. 163 at p. 3)

DOE has analyzed this issue for many years. For instance, in its August 4, 2006, NOPR, DOE summarized its legal authority to regulate new, used and refurbished transformers and sought public comment on the issue. 71 FR 44356, 44366–67. In that notice, DOE noted that for the entire history of its appliance and commercial equipment energy conservation standards program, DOE has not sought to regulate used units that have been reconditioned or rebuilt, or that have undergone major repairs. DOE stated that given there is no legislative history to ascertain Congressional intent and the potential ambiguity of the statutory language, this conclusion was based on detailed analysis and interpretation of numerous statutory provisions in the EPCA, namely 42 U.S.C. 6302, 6316(a) and 6317(a)(1). Importantly, DOE analyzed the meaning of a ''newly covered product'' and whether a refurbished transformer could nonetheless fall under this definition. (42 USC sec. 6302) The most reasonable interpretation of the statutory definition is that Congress intended that this provision apply to newly manufactured products and equipment the title of which has not passed for the first time to a consumer of the product. This conclusion was reiterated in the October 12, 2007 final rule. (72 FR 58203) And this remains DOE's position today. The issue was raised during the negotiations, and again, DOE emphasized that refurbished transformers were not ''covered'' equipment as defined by EPCA. (DOE No. 95 at p. 95) Despite DOE's lack of legal authority, DOE has continued to evaluate the degree to which utilities may purchase a refurbished product rather than a new transformer, as discussed above.

4. Alternative Means of Saving Energy

Rockwood Electric commented that a more effective means of saving energy than requiring energy conservation in the distribution transformers themselves would be to require that power distribution occur at higher voltages and thereby reduce resistive losses. (Rockwood Electric, No. 167 at p. 1) CFCU advocated that DOE seek more cost-effective means of finding efficiency in electric distribution systems than by increasing efficiency standards for distribution transformers. (CFCU, No. 190 at p. 2) DOE has no plans to address distribution voltage ratings in the present rulemaking, and does not consider the possibility to fall within its scope of coverage.

5. Alternative Rulemaking Procedures

Prior to publication of the NOPR, DOE held a series of negotiating sessions to discuss standards for all three types of distribution transformer under the Negotiated Rulemaking Act. The negotiating parties succeeded in arriving at a consensus standard for medium-voltage dry-type transformers, which is adopted in today's rule. Such adoption was supported by a broad spectrum of parties as discussed previously (Advocates, 4/10/12 comment at p. 2) Several parties commented on the negotiated rulemaking process.

Despite praising the consensus agreement on the medium-voltage-dry-type units, the Advocates commented that overall the process ''produced virtually no benefits.'' (Advocates, No. 186 at p. 14) In contrast, NEMA commented that the process was extremely valuable and resulted in a better analysis. (NEMA, No. 170 at p. 2) Eaton remarked that the negotiation process improved the resulting proposal for LVDT distribution transformers and was a more efficient vehicle for considering stakeholder input. (Eaton, No. 157 at p. 2) Progress Energy recommended that the spirit of the negotiating committee be retained indefinitely through formation of a task force of stakeholders that could advise DOE in the future. (PE, No. 192 at p. 2)

DOE appreciates feedback on the negotiation process and will consider its use in appropriate future rulemakings. Currently, DOE has no plans to form a task force on distribution transformer standards.

6. Proposed Standards—Weighting of Benefits vs. Burdens

DOE received many comments that supported or criticized the Department's weighing of the benefits and burdens in its selection of the proposed levels, particularly for liquid-immersed and low-voltage dry type transformers. The first section below presents general comments on all of the transformer superclasses, and the following sections present comments specifically on each of the superclasses. The final section presents a response to the comments by DOE.

a. General Comments

Many stakeholders expressed their support for the standards proposed by DOE. (AK, No. 146 at p. 143; ATI, No. 146 at p. 7; ATI, No. 181 at p. 1–2; CDA, No. 153 at p. 1; ComEd, No. 184 at p. 1; Cooper, No. 165 at p. 1; DE, No. 179 at p. 1; JEC, No. 173 at p. 2; KAEC, No. 126 at p. 1–2; KAEC, No. 149 at p. 7; NEMA, No. 146 at p. 146; NRECA, No. 146 at p. 158; PECO, No. 196 at p. 1; UAW, No. 194 at p. 1; USW, No. 148 at p. 1; Adams Electrical Coop, No. 13) Others pointed out that these levels are well-balanced, allowing cold rolled grain-oriented steel (CRGO)/amorphous competition, energy savings, and benefits to consumers without unduly harming manufacturers. (ATI, No. 146 at p. 9; Cooper, No. 143 at p. 1; Cooper, No. 146 at p. 13–14; (FedPac, No. 132 at p. 1 and pp. 3–4; HVOLT, No. 144 at p. 1 and pp. 10–11; NEMA, No. 146 at p. 12–13; Prolec-GE, No. 146 at p. 14–15; Schneider, No. 180 at p. 1; USW, No. 148 at p. 1) Other parties agreed, noting that a higher standard would cause a transition to amorphous steel, and urged DOE not to move to higher standard levels, as the proposed standards are the highest justified levels. (USW, No. 148 at p. 2; Weststar, No. 169 at p. 1 and p. 4; Adams Electrical Coop, No. 163 at p. 1; APPA, No. 191 at p. 2; Steelmakers, No. 188 at p. 2; PECO, No. 196 at p. 1; NEMA, No. 170 at p. 2; MTEMC, No. 210 at p. 1; EEI, No. 185 at p. 2; BG&E, No. 182 at p. 2; BSE, No. 152 at p. 1) ATI agreed, noting that the NOPR efficiency levels are the proper levels to ensure M3 and amorphous metals are cost competitive with each other. (ATI No. 181 at p. 2) KAEC commented that increased standards could pose a threat to small manufacturers. (KAEC, No. 126 at p. 2) BSE commented that an increase in standards would increase the capital expense of the transformer, which will in turn have a negative impact on rates that consumers are charged for their electricity with very minimal gains in efficiency. (BSE, No. 152 at p. 1) NEMA noted that there are no utility problems at the current proposed levels. (NEMA, No. 170 at p. 13) Steelmakers commented that DOE's proposal for liquid-immersed transformers correctly states that the standards it is proposing will not lessen the utility or performance of distribution transformers, while noting that increasing standards would negatively impact utility. (Steelmakers, No. 188 at pp. 15–16) AEC and NRECA both noted that under any revised analysis, DOE should not consider increasing the proposed efficiency levels, as the evidence has shown that there would be many negative impacts on domestic steelmakers, domestic transformer manufacturers, electric utilities, and end-use customers. (AEC, No. 163 at p. 1; NRECA, No. 172 at pp. 2, 6) NRECA supported the proposed efficiency levels in the NOPR as they minimize the concerns associated with size and weight issues. (NRECA, No. 172 at p. 8) APPA members recommend that the proposed efficiency levels should be viewed as the maximum achievable levels. (APPA, No. 191 at p. 2)

Other parties believe that DOE should choose more stringent efficiency levels. ASAP, ACEEE, NRDC and NPCC stated that a more thorough consideration of the record and completion of critical missing or incomplete analyses will lead DOE to the conclusion that higher standards are justified for both low-voltage dry-type and medium-voltage liquid-immersed transformers. They stated that higher standards than those proposed would yield shorter paybacks for consumers and much larger environmental and energy system benefits. The Advocates noted that other major countries, including China and India, make use of amorphous core transformers to a greater degree than does the United States. (Advocates, No. 186 at pp. 2–3) Metglas requested that DOE revise the proposed regulation because it deprives consumers of billions of dollars in potential energy savings and millions of tons of harmful pollution reductions by favoring older, less efficient transformer designs over innovative U.S.-made energy-efficient technologies. (Metglas, No. 102 at p. 3)

EMS Consulting commented that DOE's rationale for setting lower standards to minimize impact on the distribution transformer industry will cost the country significant potential energy savings and recommended higher standards for both liquid-immersed and low-voltage dry-type transformers. Based on EMS' calculations, a standard set between EL 1.5 and EL 2 for liquid-immersed transformers would allow the nation to gain additional energy savings while increasing demand for grain-oriented steels and creating a new market for amorphous steel. The market for grain-oriented steels will also expand as a result of higher standards for low-voltage dry-type transformers, which may be able to achieve EL 3 with M4/M5 material and butt-lap cores or EL 4 with step-lap mitering, and the investment required by industry to meet EL 4 is well-justified considering benefits to end users. (EMS, No. 178 at p. 8)

Some stakeholders commented that the proposed standards were too high and were not economically justified. (WE, No. 168 at p. 1,3; Sioux Valley Energy, No. 159 at p. 1; Polk-Burnett Electric Cooperative, No. 175 at p. 1; PJE, No. 202 at p. 1; MEC, No. 161 at p. 1; East Miss. EPA, No. 166 at p. 1; Central Electric Power Coop, No. 176 at p. 1) Specifically, stakeholders noted that the proposed standards would cause hardships to electricity consumers. (KEC, No. 164 at p. 1; BEC, No. 204 at p. 1; BEC, No. 205 at p. 1; CHELCO, No. 203 at p. 1) East Central Energy agreed, noting that the proposed standards achieve little to no benefit and would cost extra for manufacturers. (East Central Energy, No. 160 at p. 1) BEC pointed out that the cost savings were overstated in the NOPR. (BEC, No. 205 at p. 1) Westar Energy commented that they were hesitant to support even an increase to EL1 for liquid-immersed units. (Westar, No. 169 at p. 1) CCED noted that the standards proposed in the NOPR were without merit and the existing 2010 standards should be maintained instead. (CCED, No. 174 at p. 3)

Some stakeholders expressed opinions about how steel availability should factor into the standards that DOE chooses. Progress Energy urged DOE not to set a standard that would result in the use of specific steels that have questionable supply availability, noting that M3 and M4 grades of core steel should be required for 85 percent or more of any required efficiency level. (PE, No. 192 at p. 7–8) Earthjustice felt that DOE failed to rationally analyze the potential impacts associated with steel production capacity constraints while deciding on standard levels. (Earthjustice, No. 195 at p. 1) The Advocates noted that in the long term, amorphous steel is likely to predominate in the transformer market due to higher efficiency. They commented that countries such as China and India are fostering a transition to highly efficient transformers and more amorphous steel is used in these countries than in the United States. (Advocates, No. 186 at pp. 13–14)

b. Standards on Liquid-Immersed Distribution Transformers

The Advocates felt that DOE emphasized the worst-case scenario for manufacturer impacts when rejecting TSL 2 and TSL 3 for liquid-immersed transformers. (Advocates, No. 186 at p. 12) They noted that at TSL 4 for liquid-immersed transformers, potential costs to manufacturers are still far less than potential benefits to consumers. (Advocates, No. 186 at p. 11) The Advocates stated that DOE estimates that TSL 4 could result in a potential loss of industry value of 12 percent under the ''maintenance of profits'' scenario, a potential impact well within the norm of DOE estimates for other standards rulemakings. (Advocates, No. 186 at p. 3) The Advocates stated that a standard in the range of TSL 3.5 to TSL 4 would promote robust competition between silicon steel and amorphous metal, maximizing benefits for consumers and producing much larger energy savings for the Nation. They stated that TSL 4 or 3.5 can be met even if amorphous metal supplies do not increase. They added that if DOE feels that more time would provide greater confidence that supply of amorphous steel could increase to help meet market needs triggered by a TSL 3.5 or TSL 4 standard, they would not object to moving the effective date of today's rule a year or two further into the future. (Advocates, No. 186 at pp. 9–11)

At the NOPR public meeting, ASAP commented that the standard levels proposed for liquid-immersed transformers are far below the point that would maximize consumer benefits because DOE put an inordinate amount of weight on manufacturer impacts to the detriment of consumer benefits. (ASAP, No. 146 at p. 27) They also commented that DOE placed significant weight on steel manufacturer impacts but did not conduct a more detailed analysis on those impacts, in particular one which includes employment at each TSL for steel manufacturers. (ASAP, No. 146 at p. 143) ASAP recommended that DOE select EL 2 for liquid-immersed units. (ASAP, No. 146 at p. 18)

Berman Economics stated that DOE's rationale for choosing TSL 1 for liquid-immersed transformers, that a higher standard would require an unacceptable increase in cost to industry, suggests that DOE prefers that consumers pay more money than to require additional investment on the part of manufacturers. (Berman Economics, No. 150 at p. 2–3) Berman Economics also argues that DOE's rejection of EL 2 for liquid-immersed transformers is an indication that DOE is focused on avoiding competition for silicon steel even at the cost of energy and consumer savings and environmental preservation. (Berman Economics, No. 150 at p. 4) EMS recommended a level between EL 1.5 and EL 2.0. (EMS, No. 178 at p. 7)

Several stakeholders felt that DOE relied on impacts on small manufacturers too heavily, and noted that small manufacturers can build up to TSL 3. (Earthjustice, No. 195 at p. 2; Advocates, No. 186 at p. 11; NEEP, No. 193 at p. 1; ASAP, No. 146 at pp. 26–27; CA IOUs, No. 189 at p. 3)

Some stakeholders stated that setting higher standards may result in reduced benefits to consumers. EEI stated that utilities are concerned that if standards are set so high that transformer manufacturers need to use steels with possible supply constraints, there may be negative impacts on the electrical grid, which would have a negative impact on consumers. (EEI, No. 185 at p. 13)

EEI stated that several members expressed concern that the more efficient transformers will be larger in size (height, width, and depth), which will have an impact for all retrofit situations, and they would have much larger weights, which would increase costs in terms of installation and pole structural integrity for retrofits of existing pole-mounted transformers. (EEI, No. 185 at p. 11) A number of electric utilities made similar comments. (BG&E, No. 182 at p. 6;

ComEd, No. 184 at p. 11; EMEPA, No. 166 at p. 1; PECO, No. 196 at p. 1; Pepco, No. 145 at p. 3; WE, No. 168 at p. 3; Westar, No. 169 at p. 2) Howard Industries also stated that the increased size and weight will sometimes be a constraint and result in increased costs. (HI, No. 151 at p. 7)

A number of parties expressed specific concerns about size and space constraints for network/vault transformers. (BG&E, No. 182 at p. 6; ComEd, No. 184 at p. 11; Pepco, No. 145 at pp. 2–3; PE, No. 192 at p. 8; Prolec-GE, No. 177 at p. 12) These concerns lead several parties to recommend a separate equipment class for network/vault transformers. (DOE addresses this issue in section IV.A.2.) EEI and several electric utilities stated that efficiency standards for network/vault transformers should be the same as the efficiency levels that have been in effect since January 1, 2010. (EEI, No. 185 at p. 3; Pepco, No. 145 at p. 2; PE, No. 192 at p. 8; Prolec-GE, No. 177 at p. 12)

Northern Wasco supported the DOE proposal for liquid-immersed units and believed anything beyond would not be cost-effective. (NWC, No. 147 at p. 1) UAW agreed, noting that any level above TSL 1 would not be economically justified. (UAW, No. 194 at p. 2) ATI stated that efficiency levels in excess of the NOPR proposal would create a non-competitive market for new medium-voltage liquid-type designs that would eliminate projected LCC savings. (ATI, No. 54 at p. 2) Steelmakers commented that promulgating energy conservation standards greater than TSL 1 for liquid-immersed transformers would transfer significant competitive power to the sole maker of amorphous metal. (Steelmakers, No. 188 at pp. 9–10)

After the supplementary analysis was presented, which included the new TSLs described in section IV.O.1, a handful of stakeholders recommended that DOE adopt one of the TSLs presented in the supplementary analysis. The Advocates recommended that DOE adopt TSL C, following the supplementary rulemaking process, to increase energy savings relative to the levels proposed in the NOPR and increase life cycle cost savings. (Advocates, No. 235 at p. 2) They added that if DOE wants to foster a more gradual market growth for amorphous metal, TSL D would achieve such an outcome by lowering the standard for pole type transformers, but would still approach the national savings of TSL C. (Advocates, No. 235 at p. 1) Berman Economics agreed that TSL C or D should be selected as they provide the best balance. (Berman Economics, No. 221 at p. 1) NEMA stated that TSL A was the only level presented in the supplementary rulemaking that met the three principles that they applied during the rulemaking process to select levels, but suggested that the level be moved to EL 0 for design line 2. (NEMA, No. 225 at p. 4) Prolec-GE expressed their support for TSL A as well, believing that these efficiency levels provide additional energy savings while preserving manufacturers' ability to use both silicon and amorphous steel to meet the demand of the market. In the absence of TSL A, they recommended TSL 2 as the maximum possible alternative, which they noted would result in higher cost and heavier and larger pole units. (Prolec-GE, No. 238 at p. 3)

c. Standards on Low-Voltage Dry-Type Distribution Transformers

The Advocates stated that for LVDT transformers, DOE rejected TSL 3 despite its own economic analysis showing greater net consumer savings, and mean paybacks of five to twelve years, well within a transformer's typical 30-year lifespan. (Advocates, No. 186 at p. 3) They stated that a more thorough investigation of impacts on domestic small manufacturers and a better balancing of public benefits and manufacturer impacts will lead DOE to adopt TSL 3, the maximum level which yields net present value benefits for consumers and can incontrovertibly be achieved using silicon steel cores. They said that if DOE rejects TSL 3, the agency should at least adopt TSL 2, which represents the NEMA Premium® level (30 percent reduction in losses) for all transformers. They added that DOE overestimated the savings from the proposed standards (i.e., TSL 1). (Advocates, No. 186 at pp. 3–4) However, they recommend that if TSL 3 is not adopted, TSL 2 should be chosen, as a number of manufacturers are already committed to manufacturing at NEMA Premium®. (Advocates, No. 186 at p. 7–8) ASAP commented that DOE should select EL 4 for DL7 and DL8. (ASAP, No. 146 at p. 19) EMS stated that low-voltage dry-type standards should be set at TSL 2 or TSL 3. (EMS, No. 178 at p. 7)

CA IOUs stated that TSL 3 is the highest achievable efficiency level at which low-voltage dry-type distribution transformers can be constructed using grain-oriented steel, and they recommend that DOE consider adopting standards at this level. They noted that while DOE expresses concern that small manufacturers are disproportionately impacted by standards for low-voltage dry-type transformers, DOE's analysis shows that there are actually very few small manufacturers in this market, and that those small manufacturers that do exist in the market primarily focus on design lines that are exempted from coverage. (CA IOUs, No. 189 at pp. 2–3)

Schneider Electric and FedPac both expressed support for the low-voltage dry type proposed standards in the NOPR. (FedPac, No. 132 at p. 2; Schneider, No. 180 at p. 1) FedPac noted that the proposed standards may be slightly high for 3-phase above 150 kVA and may put small manufacturers at risk due to potentially large capital investments necessary to remain in business at these levels. (FedPac, No. 132 at pp. 2–3)

Some stakeholders demonstrated support for NEMA Premium® levels for low-voltage dry-type transformers. Eaton noted that NEMA Premium® represents an opportunity to produce efficiency gains and encourage new technologies and recommended adopting NEMA Premium® for DL7 and DL8. (Eaton, No. 157 at p. 2) NEEP pointed out that industry parties suggested higher efficiency on the record during negotiations, including NEMA Premium®. (NEEP, No. 193 at p. 5)

NEMA recommended that DOE select ELs 0, 2 and 2 for DLs 6, 7 and 8, respectively. NEMA noted that NEMA Premium® was still in development. (NEMA, No. 170 at p. 5) NEMA expressed concern that high efficiency standards for LVDT transformers would hurt small U.S. manufacturers. (NEMA, No. 170 at p. 5)

d. Standards on Medium-Voltage Dry-Type Distribution Transformers

The Advocates expressed support for the proposed standards for medium-voltage dry-type (MVDT) transformers. (The Advocates, No. 186 at p. 2) FedPac noted that the DOE was correct in its NOPR decision to not increase standards for single-phase MVDTs. (FedPac, No. 132 at p. 2)

NEMA made specific recommendations for medium-voltage, dry type transformers. First, it recommended for DL13 that the efficiency level allow for 10 percent more loss that DL12, as these are high BIL transformers. Second, it noted that for single-phase transformers the single-phase efficiency should be less than the three-phase efficiency by a maximum of 30 percent higher losses and should not exceed 2010 standard. (NEMA, No. 170 at p. 4)

NEMA stated that for medium-voltage dry-type transformers used in high-rise buildings, it recommended different treatment because of size and weight limitations (elevator capacity) in existing installations. It stated that manufacturers are confident that the sizes and weights of the high-rise MVDT transformer in compliance with the current standards can continue to be used without significant problems, but going to any higher efficiency levels for high-rise MVDT transformers will adversely impact the continued installation and replacement of this type of transformer. (NEMA, No. 170 at p. 4) BG&E and ComEd also stated that designs that increase the size and weight of dry-type transformers could prohibit replacement of existing units used in high-rise buildings. (BG&E, No. 182 at p. 6; ComEd, No. 184 at p. 11)

e. Response to Comments on Standards Proposed in Notice of Proposed Rulemaking

DOE acknowledges the comments described above and has taken them into account in developing today's final rule. As stated previously, DOE seeks to set the highest energy conservation standards that are technologically feasible, economically justified, and that will result in significant energy savings. In section V.C, DOE explains why it has adopted the standards established by this final rule, and it addresses the issues raised in the preceding comments. DOE agrees with many of the concerns associated with higher efficiency transformers, and these considerations contributed to the selection of today's standards. In particular, DOE believes that the increase in medium-voltage dry-type distribution transformer size and weight for the efficiency levels in today's final rule, which were unanimously agreed to by the negotiation committee, will not adversely impact the continued installation and replacement of these transformers.

V. Analytical Results and Conclusions

A. Trial Standard Levels

Table V.1 through Table V.3 present the TSLs analyzed and the corresponding efficiency level for the representative unit in each transformer design line. The mapping of TSLs to corresponding efficiency levels for each design line is described in detail in chapter 10, section 10.2.2.3 of the final rule TSD. The baseline in the tables is equal to the current energy conservation standards.

For liquid-immersed distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents an increase in efficiency where a diversity of electrical steels are cost-competitive and economically feasible for all design lines; TSL 2 represents EL1 for all design lines; TSL 3 represents the maximum efficiency level achievable with M3 core steel; TSL 4 represents the maximum NPV with 7 percent discounting; TSL 5 represents EL 3 for all design lines; TSL 6 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 7 represents the maximum technologically feasible level (max tech).

For low-voltage dry-type distribution transformers, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents the maximum efficiency level achievable with M6 core steel; TSL 2 represents EL 3 for design line 7, EL 2 for design line 8 and no efficiency increase for design line 6; TSL 3 represents the maximum EL achievable using butt-lap miter core manufacturing for single-phase distribution transformers, and full miter core manufacturing for three-phase distribution transformers; TSL 4 represents the maximum NPV with 7 percent discounting; TSL 5 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 6 represents the maximum technologically feasible level (max tech).

For medium-voltage dry-type distribution transformers based on the subcommittee consensus detailed in section II.B.2, above, the efficiency levels in each TSL can be characterized as follows: TSL 1 represents EL1 for all design lines; TSL 2 represents an increase in efficiency where a diversity of electrical steels are cost-competitive and economically feasible for all design lines; TSL 3 represents the maximum NPV with 7 percent discounting; TSL 4 represents the maximum source energy savings with positive NPV with 7 percent discounting; and TSL 5 represents the maximum technologically feasible level (max tech).

TABLE V.1—EFFICIENCY VALUES OF THE TRIAL STANDARD LEVELS FOR LIQUID-IMMERSED TRANSFORMERS BY DESIGN LINE

Design line	Baseline	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
	Percent							
1	99.08	99.11	99.16	99.16	99.22	99.25	99.31	99.50
2	98.91	98.95	99.00	99.00	99.07	99.11	99.18	99.41
3	99.42	99.49	99.48	99.51	99.57	99.54	99.61	99.73
4	99.08	99.16	99.16	99.16	99.22	99.25	99.31	99.60
5	99.42	99.48	99.48	99.51	99.57	99.54	99.61	99.69

TABLE V.2 EFFICIENCY VALUES OF THE TRIAL STANDARD LEVELS FOR LOW-VOLTAGE DRY-TYPE TRANSFORMERS BY DESIGN LINE

Design line	Baseline	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
	Percent						
6	98.00	98.00	98.00	98.80	99.17	99.17	99.44
7	98.00	98.47	98.60	98.80	99.17	99.17	99.44
8	98.60	99.02	99.02	99.25	99.44	99.58	99.58

TABLE V.3—EFFICIENCY VALUES OF THE TRIAL STANDARD LEVELS FOR MEDIUM-VOLTAGE DRY-TYPE TRANSFORMERS BY DESIGN LINE

Design line	Baseline	TSL				
		1	2	3	4	5
	Percent					
9	98.82	98.93	98.93	99.04	99.04	99.55
10	99.22	99.29	99.37	99.37	99.37	99.63
11	98.67	98.81	98.81	99.13	99.13	99.50
12	99.12	99.21	99.30	99.46	99.46	99.63
13A	98.63	98.69	98.69	99.04	99.84	99.45
13B	99.15	99.19	99.28	99.28	99.28	99.52

B. Economic Justification and Energy Savings

1. Economic Impacts on Customers

a. Life-Cycle Cost and Payback Period

To evaluate the net economic impact of standards on transformer customers, DOE conducted LCC and PBP analyses for each TSL. In general, higher-efficiency equipment would affect customers in two ways: (1) Annual operating expense would decrease, and (2) purchase price would increase. Section IV.F.2 of this preamble discusses the inputs DOE used for calculating the LCC and PBP. The LCC and PBP results are calculated from transformer cost and efficiency data that are modeled in the engineering analysis (section IV.C). During the negotiated rulemaking, DOE presented separate transformer cost data based on 2010 and 2011 material prices to the committee members. DOE conducted its LCC and PBP analysis utilizing both the 2010 and 2011 material price cost data. The average results of these two analyses are presented here.

For each design line, the key outputs of the LCC analysis are a mean LCC savings and a median PBP relative to the base case, as well as the fraction of customers for which the LCC will decrease (net benefit), increase (net cost), or exhibit no change (no impact) relative to the base-case product forecast. No impacts occur when the base-case equals or exceeds the efficiency at a given TSL. Table V.4 through Table V.17 show the key results for each transformer design line.

TABLE V.4—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 1 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4 **	5 **	6	7
Efficiency (%)	99.11	99.16	99.16	99.22	99.25	99.31	99.50
Transformers with Net LCC Cost (%) *	37.3	44.2	44.2	7.0	7.0	11.2	42.6
Transformers with Net LCC Benefit (%) *	62.5	55.6	55.6	92.9	92.9	88.8	57.4
Transformers with No Change in LCC (%) *	0.2	0.2	0.2	0.2	0.2	0.0	0.0
Mean LCC Savings ($)	83	153	153	696	696	618	365
Median PBP (Years)	17.7	24.7	24.7	10.8	10.8	13.7	24.6

* Rounding may cause some items to not total 100 percent.
** The results are the same for these TSLs because in both cases customers are expected to purchase the least cost transformer designs that meet the EL. The least cost transformer designs are the same for TSLs 4 and 5.

TABLE V.5—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 2 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	98.95	99.00	99.00	99.07	99.11	99.18	99.41
Transformers with Net LCC Cost (%) *	41.5	18.2	18.2	11.4	13.1	17.8	67.2
Transformers with Net LCC Benefit (%) *	55.2	81.8	81.8	88.6	86.9	82.2	32.8
Transformers with No Change in LCC (%) *	3.4	0.0	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	66	278	278	343	330	311	−579
Median PBP (Years)	5.9	9.9	9.9	11.1	13.0	15.5	31.6

* Rounding may cause some items to not total 100 percent.

TABLE V.6—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 3 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.49	99.48	99.51	99.57	99.54	99.61	99.73
Transformers with Net LCC Cost (%)*	14.5	13.9	12.0	4.0	5.3	4.0	29.9
Transformers with Net LCC Benefit (%)*	84.2	84.8	86.9	95.9	94.7	96.0	70.1
Transformers with No Change in LCC (%)*	1.3	1.3	1.2	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	2709	2407	3526	5527	5037	6942	4491
Median PBP (Years)	8.5	8.3	5.8	6.5	6.4	7.2	19.1

* Rounding may cause some items to not total 100 percent.

TABLE V.7—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 4 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.16	99.16	99.16	99.19	99.22	99.25	99.50
Transformers with Net LCC Cost (%)*	6.6	6.6	6.6	7.6	2.5	2.5	5.9
Transformers with Net LCC Benefit (%)*	92.8	92.8	92.8	91.8	96.9	96.9	94.1
Transformers with No Change in LCC (%)*	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Mean LCC Savings ($)	977	977	977	1212	3603	3603	4349
Median PBP (Years)	7.0	7.0	7.0	9.1	5.6	5.6	10.2

* Rounding may cause some items to not total 100 percent.

TABLE V.8—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 5 REPRESENTATIVE UNIT

	Trial standard level						
	1	2	3	4	5	6	7
Efficiency (%)	99.48	99.48	99.51	99.57	99.54	99.61	99.69
Transformers with Net LCC Cost (%)*	30.5	30.5	19.9	9.8	14.8	9.1	41.9
Transformers with Net LCC Benefit (%)*	69.1	69.1	80.0	90.2	85.2	91.0	58.1
Transformers with No Change in LCC (%)*	0.4	0.4	0.1	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	3668	3668	6852	10382	8616	12014	4619
Median PBP (Years)	6.5	6.5	6.5	9.1	8.5	11.4	22.5

*Rounding may cause some items to not total 100 percent.

TABLE V.9—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 6 REPRESENTATIVE UNIT

	Trial standard level					
	1	2	3	4	5	6
Efficiency (%)	98.00	98.00	98.93	99.17	99.17	99.44
Transformers with Net LCC Cost (%)*	0.0	0.0	16.5	37.8	37.8	96.6
Transformers with Net LCC Benefit (%)*	0.0	0.0	83.5	62.2	62.2	3.4
Transformers with No Change in LCC (%)*	100.0	100.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	0	0	325	148	148	-992
Median PBP (Years)	0.0	0.0	12.4	15.7	15.7	31.7

* Rounding may cause some items to not total 100 percent.

TABLE V.10—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 7 REPRESENTATIVE UNIT

	Trial standard level					
	1	2	3	4	5	6
Efficiency (%)	98.47	98.60	98.80	99.17	99.17	99.44
Transformers with Net Increase in LCC (%)*	1.5	1.3	1.7	3.3	3.3	45.6

TABLE V.10—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 7 REPRESENTATIVE UNIT—Continued

	Trial standard level					
	1	2	3	4	5	6
Transformers with Net LCC Savings (%) *	98.4	98.7	98.3	96.7	96.7	54.4
Transformers with No Impact on LCC (%) *	0.1	0.1	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	1526	1678	1838	2280	2280	212
Median PBP (Years)	3.9	3.6	4.1	6.3	6.3	16.8

*Rounding may cause some items to not total 100 percent.

TABLE V.11—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 8 REPRESENTATIVE UNIT

	Trial standard level					
	1	2	3	4	5	6
Efficiency (%)	99.02	99.02	99.25	99.44	99.58	99.58
Transformers with Net Increase in LCC (%) *	4.7	4.7	13.3	9.0	79.3	79.3
Transformers with Net LCC Savings (%) *	95.3	95.3	86.7	91.0	20.7	20.7
Transformers with No Impact on LCC (%) *	0.0	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	2588	2588	2724	4261	−2938	−2938
Median PBP (Years)	7.7	7.7	11.3	10.1	22.5	22.5

* Rounding may cause some items to not total 100 percent.

TABLE V.12—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 9 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	98.93	98.93	99.04	99.04	99.55
Transformers with Net Increase in LCC (%) *	3.6	3.6	5.9	5.9	57.4
Transformers with Net LCC Savings (%) *	83.2	83.2	94.1	94.1	42.6
Transformers with No Impact on LCC (%) *	13.3	13.3	0.0	0.0	0.0
Mean LCC Savings ($)	787	787	1514	1514	−299
Median PBP (Years)	2.6	2.6	6.1	6.1	18.5

* Rounding may cause some items to not total 100 percent.

TABLE V.13—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 10 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	99.29	99.37	99.37	99.37	99.63
Transformers with Net Increase in LCC (%) *	0.7	17.9	17.9	17.9	88.8
Transformers with Net LCC Savings (%) *	98.8	82.1	82.1	82.1	11.2
Transformers with No Impact on LCC (%) *	0.5	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	4604	4455	4455	4455	−14727
Median PBP (Years)	1.1	8.6	8.6	8.6	27.5

* Rounding may cause some items to not total 100 percent.

TABLE V.14—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 11 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	98.81	98.81	99.13	99.13	99.50
Transformers with Net Increase in LCC (%) *	21.9	21.9	25.9	25.9	82.7
Transformers with Net LCC Savings (%) *	78.1	78.1	74.1	74.1	17.4
Transformers with No Impact on LCC (%) *	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	996	996	1849	1849	−4166
Median PBP (Years)	10.6	10.6	13.6	13.6	24.1

* Rounding may cause some items to not total 100 percent.

TABLE V.15—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 12 REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	99.21	99.30	99.46	99.46	99.63
Transformers with Net Increase in LCC (%)*	7.1	7.6	17.1	17.1	85.4
Transformers with Net LCC Savings (%)*	92.9	92.4	82.9	82.9	14.6
Transformers with No Impact on LCC (%)*	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	4537	6790	8594	8594	−14496
Median PBP (Years)	6.0	8.5	12.3	12.3	24.7

* Rounding may cause some items to not total 100 percent.

TABLE V.16—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 13A REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	98.69	98.69	98.84	99.04	99.45
Transformers with Net Increase in LCC (%)*	54.2	54.2	45.5	66.3	98.5
Transformers with Net LCC Savings (%)*	45.8	45.8	54.5	33.7	1.5
Transformers with No Impact on LCC (%)*	0.0	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	−27	−27	311	−1019	−12053
Median PBP (Years)	16.1	16.1	16.2	20	35.3

* Rounding may cause some items to not total 100 percent.

TABLE V.17—SUMMARY LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS FOR DESIGN LINE 13B REPRESENTATIVE UNIT

	Trial standard level				
	1	2	3	4	5
Efficiency (%)	99.19	99.28	99.28	99.28	99.52
Transformers with Net Increase in LCC (%)*	30.5	27.3	27.3	27.3	70.4
Transformers with Net LCC Savings (%)*	69.3	72.7	72.7	72.7	29.6
Transformers with No Impact on LCC (%)*	0.2	0.0	0.0	0.0	0.0
Mean LCC Savings ($)	2494	4346	4346	4346	−6823
Median PBP (Years)	4.5	12.2	12.2	12.2	20.6

* Rounding may cause some items to not total 100 percent.

b. Customer Subgroup Analysis

In the customer subgroup analysis, DOE estimated the LCC impacts of the distribution transformer TSLs on purchasers of vault-installed transformers (primarily urban utilities). DOE included only the three-phase liquid-immersed design lines in this analysis, since those types account for the vast majority of vault-installed transformers. Table V.18 shows the mean LCC savings at each TSL for this customer subgroup.

Chapter 11 of the final rule TSD explains DOE's method for conducting the customer subgroup analysis and presents the detailed results of that analysis.

TABLE V.18—COMPARISON OF MEAN LIFE-CYCLE COST SAVINGS FOR LIQUID-IMMERSED TRANSFORMERS PURCHASED BY CONSUMER SUBGROUP

[2011$]

Design line	Trial standard level						
	1	2	3	4	5	6	7
Medium Vault Replacement Subgroup							
4	−1236	−1236	−1236	−3078	−759	−759	−377
5	2387	2387	−6183	−4421	−6156	−2905	4619
All Customers							
4	977	977	977	1212	3603	3603	4349
5	3668	3668	6852	10382	8616	12014	4619

c. Rebuttable Presumption Payback

As discussed in section IV.F.3.j, EPCA establishes a rebuttable presumption that an energy conservation standard is economically justified if the increased purchase cost for equipment that meets the standard is less than three times the value of the first-year energy savings resulting from the standard. (42 U.S.C. 6295(o)(2)(B)(iii), 6316(a)) DOE calculated a rebuttable-presumption PBP for each TSL to determine whether DOE could presume that a standard at that level is economically justified. As required by EPCA, DOE based the calculations on the assumptions in the DOE test procedure for distribution transformers. (42 U.S.C. 6295(o)(2)(B)(iii), 6316(a)) As a result, DOE calculated a single rebuttable-presumption payback value, and not a distribution of PBPs, for each TSL. Table V.19 and Table V.21 show the rebuttable-presumption PBPs for the considered TSLs. The rebuttable presumption is fulfilled in those cases where the PBP is three years or less. However, DOE routinely conducts an economic analysis that considers the full range of impacts to the customer, manufacturer, Nation, and environment, as required under 42 U.S.C. 6295(o)(2)(B)(i). The results of that analysis serve as the basis for DOE to definitively evaluate the economic justification for a potential standard level (thereby supporting or rebutting the results of any three-year PBP analysis). Section V.C addresses how DOE considered the range of impacts to select today's standard.

TABLE V.19—REBUTTABLE-PRESUMPTION PAYBACK PERIODS (YEARS) FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Design line	Rated capacity *kVA*	Trial standard level						
		1	2	3	4	5	6	7
1	50	17.5	17.7	17.7	12.5	12.5	14.9	20.0
2	25	22.5	20.7	20.7	16.5	17.1	18.3	34.2
3	500	9.1	9.0	9.0	7.6	8.0	7.5	16.9
4	150	8.1	8.1	8.1	5.5	5.5	5.5	17.5
5	1500	13.1	13.1	8.4	8.5	8.7	10.0	19.9

TABLE V.20—REBUTTABLE-PRESUMPTION PAYBACK PERIODS (YEARS) FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Design line	Rated capacity *kVA*	Trial standard level					
		1	2	3	4	5	6
6	25	0.0	0.0	12.5	14.5	14.5	25.7
7	75	3.8	3.5	4.0	6.1	6.1	14.1
8	300	6.5	6.5	10.0	9.3	19.4	19.4

TABLE V.21—REBUTTABLE-PRESUMPTION PAYBACK PERIODS (YEARS) FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Design line	Rated capacity *kVA*	Trial standard level				
		1	2	3	4	5
9	300	1.8	1.8	4.2	4.2	14.1
10	1500	1.3	5.5	5.5	5.5	19.9
11	300	10.0	10.0	12.7	12.7	18.3
12	1500	5.9	7.3	11.5	11.5	19.7
13A	300	12.7	12.7	12.5	21.4	27.9
13B	2000	5.7	10.4	10.4	10.4	18.7

2. Economic Impact on Manufacturers

For the MIA in the February 2012 NOPR, DOE used changes in INPV to compare the direct financial impacts of different TSLs on manufacturers (77 FR 7282, February 10, 2012). DOE used the GRIM to compare the INPV of the base case (no new or amended energy conservation standards) to that of each TSL. The INPV is the sum of all net cash flows discounted by the industry's cost of capital (discount rate) to the base year. The difference in INPV between the base case and the standards case is an estimate of the economic impacts that implementing that standard level would have on the distribution transformer industry. For today's final rule, DOE continues to use the methodology presented in the NOPR at 77 FR 7282 (February 10, 2012).

a. Industry Cash-Flow Analysis Results

The tables below depict the financial impacts (represented by changes in INPV) of amended energy standards on manufacturers as well as the conversion costs that DOE estimates manufacturers would incur at each TSL. The effect of amended standards on INPV was analyzed separately for each type of distribution transformer manufacturer: liquid-immersed, medium-voltage dry-type, and low-voltage dry-type. To evaluate the range of cash flow impacts on the distribution transformer industry, DOE modeled two different scenarios using different assumptions for markups that correspond to the range of anticipated market responses to new and amended standards. These assumptions correspond to the bounds of a range of market responses that DOE anticipates could occur in the standards case (i.e., where new and amended energy conservation standards apply). Each of the two scenarios results in a unique set of cash flows and corresponding industry values at each TSL. The February 2012 NOPR discusses each of these scenarios in full, and they are also presented in chapter 12 of the TSD.

The MIA results for liquid-immersed distribution transformers are as follows:

TABLE V.22—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT MARKUP SCENARIO

	Units	Base case	Trial standard level						
			1	2	3	4	5	6	7
INPV	2011$ M	575.1	526.9	465.9	461.7	389.0	382.1	358.4	181.6
Change in INPV	2011$ M	....	(48.2)	(109.3)	(113.4)	(186.1)	(193.0)	(216.7)	(393.5)
	%	....	(8.4)	(19.0)	(19.7)	(32.4)	(33.6)	(37.7)	(68.4)
Capital Conversion Costs	2011$ M	....	25.3	57.8	60.6	92.8	96.2	101.5	124.5
Product Conversion Costs	2011$ M	....	24.2	65.2	65.7	96.1	96.1	96.1	96.1
Total Conversion Costs	2011$ M	....	49.4	123.0	126.3	188.9	192.3	197.7	220.6

*Note: Parentheses indicate negative values.

TABLE V.23—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP

	Units	Base case	Trial standard level						
			1	2	3	4	5	6	7
INPV	2011$ M	575.1	551.6	508.1	506.2	477.8	473.8	486.6	575.6
Change in INPV	2011$ M	....	(23.5)	(67.0)	(68.9)	(97.3)	(101.4)	(88.5)	0.5
	%	....	(4.1)	(11.7)	(12.0)	(16.9)	(17.6)	(15.4)	0.1
Capital Conversion Costs	2011$ M	....	25.3	57.8	60.6	92.8	96.2	101.5	124.5
Product Conversion Costs	2011$ M	....	24.2	65.2	65.7	96.1	96.1	96.1	96.1
Total Conversion Costs	2011$ M	....	49.4	123.0	126.3	188.9	192.3	197.7	220.6

At TSL 1, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$48.2 million to −$23.5 million, corresponding to a change in INPV of −8.4 percent to −4.1 percent. At this level, industry free cash flow is estimated to decrease by approximately 54.4 percent to $16.4 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

While TSL 1 can be met with traditional steels, including M3, in all design lines, amorphous core transformers will be incrementally more competitive on a first cost basis. According to manufacturer interviews, this would likely induce some manufacturers to gradually build amorphous steel transformer production capacity. Because the production process for amorphous cores is entirely separate from that of silicon steel cores, large investments in new capital, including new core cutting equipment and annealing ovens will be required. Additionally, a great deal of testing, prototyping, design and manufacturing engineering resources will be required because most manufacturers have relatively little experience, if any, with amorphous steel transformers. These capital and production conversion expenses lead to a reduction in cash flow in the years preceding the standard. In the lower-bound scenario, DOE assumes manufacturers can only maintain annual operating profit in the standards case. Therefore, these conversion investments, and manufacturers' higher working capital needs associated with more expensive transformers, drain cash flow and lead to a greater reduction in INPV, when compared to the upper-bound scenario. In the upper bound scenario, DOE assumes manufacturers will be able to fully markup and pass on the higher product costs, leading to higher operating income. This higher operating income essentially offsets the conversion costs and the increase in working capital requirements, leading to a negligible change in INPV at TSL1 in the upper-bound scenario.

At TSL 2, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$109.3 million to −$67.0 million, corresponding to a change in INPV of −19.0 percent to −11.7 percent. At this level, industry free cash flow is estimated to decrease by approximately 133.7 percent to −$12.1 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

TSL 2 requires the same efficiency levels as TSL 1, except for DL 2, which is increased from baseline to EL1. EL1, as opposed to the baseline efficiency, could induce manufacturers to build more amorphous capacity, when compared to TSL 1, because amorphous core transformers become incrementally more cost competitive. Because DL2 represents the largest share of core steel usage of all design lines, this has a significant impact on investments. There are more severe impacts on industry in the lower-bound profitability scenario when these greater one-time cash outlays are coupled with slight margin pressure. In the high-profitability scenario, manufacturers are able to maintain gross margins, mitigating the adverse cash flow impacts of the increased investment in working capital (associated with more expensive transformers).

At TSL 3, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$113.4 million to −$68.9 million, corresponding to a change in INPV of −19.7 percent to −12.0 percent. At this level, industry free cash flow is estimated to decrease by approximately 137.6 percent to −$13.6 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

TSL 3 results are similar to TSL 2 results because the efficiency levels are the same except for DL3 and DL5, which each increase to EL 2 under TSL 3. The increase in stringency makes amorphous core transformers slightly more cost competitive in these DLs, according to the engineering analysis, which would likely increase amorphous core transformer capacity needs—all other things being equal—and drive more investment to meet the standards.

At TSL 4, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$186.1 million to −$97.3 million, corresponding to a change in INPV of −32.4 percent to −16.9 percent. At this level, industry free cash flow is estimated to decrease by approximately 206.6 percent to −$38.4 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

During interviews, manufacturers expressed differing views on whether the efficiency levels embodied in TSL 4 would shift the market away from silicon steels entirely. Because DL3 and DL5 must meet EL4 at this TSL, DOE expects the majority of the market would shift to amorphous core transformers at TSL 4 and above. Even assuming a sufficient supply of amorphous steel were available, TSL 4 and above would require a dramatic build up in amorphous core transformer production capacity. DOE believes this wholesale transition away from silicon steels could seriously disrupt the market, drive small businesses to either source their cores or exit the market, and lead even large businesses to consider moving production offshore or exiting the market altogether. The negative impacts are again driven by the large conversion costs associated with new amorphous steel production lines. If the higher first costs at TSL 4 drive more utilities to refurbish rather than replace failed transformers, a scenario many manufacturers predicted at the efficiency levels and prices embodied in TSL 4, reduced transformer sales could cause further declines in INPV.

At TSL 5, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$193.0 million to −$101.4 million, or a change in INPV of −33.6 percent to −17.6 percent. At this level, industry free cash flow is estimated to decrease by approximately 210.8 percent to −$39.9 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

TSL 5 would likely shift the entire market to amorphous core transformers, leading to even greater investment needs than TSL 4, and further driving the adverse impacts discussed above.

At TSL 6, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$216.7 million to −$88.5 million, corresponding to a change in INPV of −37.7 percent to −15.4 percent. At this level, industry free cash flow is estimated to decrease by approximately 217.5 percent to −$42.3 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

The impacts at TSL 6 are similar to those DOE expects at TSL 5, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 6 compared to TSL 5.

At TSL 7, DOE estimates impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$393.5 million to $0.5 million, corresponding to a change in INPV of −68.4 percent to 0.1 percent. At this level, industry free cash flow is estimated to decrease by approximately 246.2 percent to −$52.7 million, compared to the base-case value of $36.0 million in the year before the compliance date (2015).

The impacts at TSL 7 are similar to those DOE expects at TSL 6, except that slightly more amorphous core production capacity will be needed because TSL 7-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 7 compared to TSL 6, incrementally reducing industry value.

The MIA results for low-voltage dry-type distribution transformers are as follows:

TABLE V.24—MANUFACTURER IMPACT ANALYSIS LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT MARKUP SCENARIO

	Units	Base case	Trial standard level					
			1	2	3	4	5	6
INPV	2011 $M	237.6	229.6	226.5	219.0	198.7	190.8	159.0
Change in INPV	2011 $M	....	(8.0)	(11.1)	(18.6)	(38.9)	(46.8)	(78.6)
	%	....	(3.4)	(4.7)	(7.8)	(16.4)	(19.7)	(33.1)
Capital Conversion Costs	2011 $M	....	4.5	5.3	12.0	28.5	30.7	45.6
Product Conversion Costs	2011 $M	....	2.9	3.6	5.0	8.0	8.0	8.0
Total Conversion Costs	2011 $M	....	7.4	9.0	17.0	36.5	38.7	53.6

* Note: Parentheses indicate negative values.

TABLE V.25—MANUFACTURER IMPACT ANALYSIS LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP SCENARIO

	Units	Base case	Trial standard level					
			1	2	3	4	5	6
INPV	2011 $M	237.6	252.4	249.4	265.7	279.9	298.6	356.6
Change in INPV	2011 $M	....	14.8	11.8	28.1	42.3	61.0	118.9
	%	....	6.2	5.0	11.8	17.8	25.7	50.1
Capital Conversion Costs	2011 $M	....	4.5	5.3	12.0	28.5	30.7	45.6
Product Conversion Costs	2011 $M	....	2.9	3.6	5.0	8.0	8.0	8.0
Total Conversion Costs	2011 $M	....	7.4	9.0	17.0	36.5	38.7	53.6

* Note: Parentheses indicate negative values.

At TSL 1, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$8.0 million to $14.8 million, corresponding to a change in INPV of −3.4 percent to 6.2 percent. At this level, industry free cash flow is estimated to decrease by approximately 5.0 percent to $14.5 million, compared to the base-case value of $15.2 million in the year before the compliance date (2015).

TSL 1 provides many design paths for manufacturers to comply. DOE's engineering analysis indicates manufacturers can continue to use the low-capital butt-lap core designs, meaning investment in mitering or wound core capability is not necessary. Manufacturers can use higher-quality grain oriented steels in butt-lap designs to meet TSL1, source some or all cores, or invest in modified mitering capability (if they do not already have it).

At TSL 2, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$11.1 million to $11.8 million, corresponding to a change in INPV of −4.7 percent to 5.0 percent. At this level, industry free cash flow is estimated to decrease by approximately 9.1 percent to $13.8 million, compared to the base-case value of $15.2 million in the year before the compliance date (2015).

TSL 2 differs from TSL1 in that DL7 must meet EL3, up from EL2. Comments received from the NOPR and consultations with technical experts suggest that butt-lap technology can still be used to achieve EL 3 for DL 7. However, DOE expects the high volume manufacturers which supply most of the market to employ mitered cores at this efficiency level. Therefore, the increase in conversion costs for DL 7, which represents more than three-quarters of the market by core weight in this superclass, is primarily driven by the need to purchase additional core cutting equipment to accommodate the production of larger, mitered cores. Furthermore, manufacturers also indicated that there would be a reduced burden at TSL 2 relative to TSL 1 because they would be able to standardize the use of NEMA Premium® (with the exception of DL 6).

At TSL 3, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$18.6 to $28.1 million, corresponding to a change in INPV of −7.8 percent to 11.8 percent. At this level, industry free cash flow is estimated to decrease by approximately 31.9 percent to $10.4 million, compared to the base-case value of $15.2 million in the year before the compliance date (2015).

TSL3 represents EL4 for DL6, DL7, and DL8. Although manufacturers may be able to meet EL4 using M4 steel, comments and interviews suggest uncertainty about the ability of M4 to meet EL 4 for all design lines. Manufacturers may be forced to use higher-grade and thinner steels like M3, H1, and H0. However, these thinner steels, in combination with larger cores, will dramatically slow production throughput and therefore require the industry to expand capacity to maintain current shipments. This is the reason for the increase in conversion costs. In the lower-bound profitability scenario, when DOE assumes the industry cannot fully pass on incremental costs, these investments and the higher working capital needs drain cash flow and lead to the negative impacts shown in the preservation of operating profit scenario. In the high-profitability scenario, impacts are slightly positive because DOE assumes manufacturers are able to fully recoup their conversion expenditures through higher operating cash flow.

At TSL 4, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$38.9 million to $42.3 million, corresponding to a change in INPV of −16.4 percent to 17.8 percent. At this level, industry free cash flow is estimated to decrease by approximately 87.2 percent to $1.9 million, compared to the base-case value of $15.2 million in the year before the compliance date (2015).

TSL 4 and higher would create significant challenges for the industry and likely disrupt the marketplace. DOE's conversion costs at TSL 4 assume the industry will entirely convert to amorphous wound core technology to meet the efficiency standards. Few manufacturers of distribution transformers in this superclass have any experience with amorphous steel or wound core technology and would face a steep learning curve. This is reflected in the large conversion costs and adverse impacts on INPV in the Preservation of Operating Profit scenario. Most manufacturers DOE interviewed expected many low-volume manufacturers to exit the DOE-covered market altogether if amorphous steel was required to meet the standard. As such, DOE believes TSL 4 could lead to greater consolidation than the industry would experience at lower TSLs.

At TSL 5, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$46.8 million to $61.0 million, corresponding to a change in INPV of −19.7 percent to 25.7 percent. At this level, industry free cash flow is estimated to decrease by approximately 93.9 percent to $0.9 million, compared to the base-case value of $15.2 million in the year before the compliance date (2015).

The impacts at TSL 5 are similar to those DOE expects at TSL 4, except that slightly more amorphous core production capacity will be needed because TSL 5-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 5 compared to TSL 4.

At TSL 6, DOE estimates impacts on INPV for low-voltage dry-type distribution transformer manufacturers to range from −$78.6 million to $118.9 million, corresponding to a change in INPV of −33.1 percent to 50.1 percent. At this level, industry free cash flow is estimated to decrease by approximately 138 percent to −$5.8 million, compared to the base-case value of $15.2 million in the year before the compliance date (2015).

The impacts at TSL 6 are similar to those DOE expects at TSL 5, except that slightly more amorphous core production capacity will be needed because TSL 6-compliant transformers will have somewhat heavier cores and thus require more amorphous steel. This leads to slightly greater capital expenditures at TSL 6 compared to TSL 5.

The MIA results for medium-voltage dry-type distribution transformers are as follows:

TABLE V.26—MANUFACTURER IMPACT ANALYSIS MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT MARKUP SCENARIO

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	2011 $M	68.7	67.3	65.7	57.9	58.0	34.5
Change in INPV	2011 $M	....	(1.4)	(2.9)	(10.7)	(10.7)	(34.1)
	%	....	(2.0)	(4.2)	(15.6)	(15.5)	(49.7)
Capital Conversion Costs	2011 $M	....	0.2	0.5	3.9	3.9	13.9
Product Conversion Costs	2011 $M	....	2.0	2.0	3.7	3.7	8.2
Total Conversion Costs	2011 $M	....	2.2	2.6	7.7	7.7	22.1

* Note: Parentheses indicate negative values.

TABLE V.27—MANUFACTURER IMPACT ANALYSIS MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP SCENARIO

	Units	Base case	Trial standard level				
			1	2	3	4	5
INPV	2011 $M	68.7	69.3	71.7	74.4	74.3	81.5
Change in INPV	2011 $M	....	0.7	3.0	5.7	5.6	12.9
	%	....	1.0	4.4	8.3	8.2	18.7
Capital Conversion Costs	2011 $M	....	0.2	0.5	3.9	3.9	13.9
Product Conversion Costs	2011 $M	....	2.0	2.0	3.7	3.7	8.2
Total Conversion Costs	2011 $M	....	2.2	2.6	7.7	7.7	22.1

* Note: Parentheses indicate negative values.

At TSL 1, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$1.4 million to $0.7 million, corresponding to a change in INPV of −2.0 percent to 1.0 percent. At this level, industry free cash flow is estimated to decrease by approximately 2.3 percent to $4.3 million, compared to the base-case value of $4.4 million in the year before the compliance date (2015).

TSL 1 represents EL1 for all MVDT design lines. For DL12, the largest design line by core steel usage, manufacturers have a variety of steels available to them, including M4, the most common steel in the superclass. Additionally, the vast majority of the market already uses step-lap mitering technology. Therefore, DOE anticipates only moderate conversion costs for the industry, mainly associated with slower throughput due to larger cores. Some manufacturers may need to slightly expand capacity to maintain throughput and/or modify equipment to manufacturer with greater precision and tighter tolerances. In general, however, conversion expenditures should be relatively minor compared to INPV. For this reason, TSL 1 yields relatively minor adverse changes to INPV in the standards case.

At TSL 2 (the consensus recommendation from the negotiating committee), DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$2.9 million to $3.0 million, corresponding to a change in INPV of −4.2 percent to 4.4 percent. At this level, industry free cash flow is estimated to decrease by approximately 6.0 percent to $4.2 million, compared to the base-case value of $4.4 million in the year before the compliance date (2015).

Compared to TSL 1, TSL 2 requires EL2, rather than EL1, in DLs 10, 12, and 13B. Because M4 (as well as the commonly used H1) can still be employed to meet these levels, DOE expects similar results at TSL 2 as at TSL 1. Slightly greater conversion costs will be required as the compliant transformers will have heavier cores, all other things being equal, meaning additional capacity may be necessary depending on each manufacturer's current capacity utilization rate. As with TSL 1, TSL 2 will not require significant changes to most manufacturers production processes because the thickness of the steels will not change significantly, if at all.

At TSL 3, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$10.7 million to $5.7 million, corresponding to a change in INPV of −15.6 percent to 8.3 percent. At this level, industry free cash flow is estimated to decrease by approximately 53.4 to $2.1 million, compared to the base-case value of $4.4 million in the year before the compliance date (2015).

At TSL 4, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$10.7 million to $5.6 million, corresponding to a change in INPV of −15.5 percent to 8.2 percent. At this level, industry free cash flow is estimated to decrease by approximately −53.4 percent to $2.1 million, compared to the base-case value of $4.4 million in the year before the compliance date (2015).

TSL 3 and TSL 4 require EL2 for DL9 and DL10, but EL4 for DL11 through DL13B, which hold the majority of the volume. Several manufacturers were concerned TSL 3 would require some of the high volume design lines to use H1 or H0, or transition entirely to amorphous wound cores (with which the industry has experience). Without a cost effective M-grade steel option, the industry could face severe disruption. Even assuming a sufficient supply of Hi-B steel, which is generally used and priced for the power transformer market, relatively large expenditures would be required in R&D and engineering as most manufacturers would have to move production to steel with which they have little experience. DOE estimates total conversion costs would more than double at TSL 3, relative to TSL 2. If, based on the movement of steel prices, EL4 can be met cost competitively only through the use of amorphous steel or an exotic design with little or no current place in scale manufacturing, manufacturers would face significant challenges that DOE believes would lead to consolidation and likely cause many low-volume manufacturers to exit the product line.

At TSL 5, DOE estimates impacts on INPV for medium-voltage dry-type distribution transformer manufacturers to range from −$34.1 million to $12.9 million, corresponding to a change in INPV of −49.7 percent to 18.7 percent. At this level, industry free cash flow is estimated to decrease by approximately 189.1 percent to −$3.9 million, compared to the base-case value of $4.4 million in the year before the compliance date (2015).

TSL 5 represents max-tech and yields results similar to but more severe than TSL 4 results. The engineering analysis shows that the entire market must convert to amorphous wound cores at TSL 5. Because the industry has no experience with wound core technology, and little, if any, experience with amorphous steel, this transition would represent a tremendous challenge for industry. Interviews suggest most manufacturers would exit the market rather altogether or source their cores rather than make the investments in plant, equipment, and the R&D required to meet such levels.

b. Impacts on Employment

Liquid-Immersed. Based on interviews with manufacturers and other industry research, DOE estimates that there are roughly 5,000 employees associated with DOE-covered liquid-immersed distribution transformer production and some three-quarters of these workers are located domestically. DOE does not expect large changes in domestic employment to occur due to today's standard. Manufacturers generally agreed that amorphous core steel production is more labor-intensive and would require greater labor expenditures than tradition steel core production. So long as domestic plants are not relocated outside the country, DOE expects moderate increases in domestic employment at TSL1 and TSL2. There could be a small drop in employment at small, domestic manufacturing firms if small manufacturers began sourcing cores. This employment would presumably transfer to the core makers, some of whom are domestic and some of whom are foreign. There is a risk that higher energy conservation standards that largely require the use of amorphous steel could cause even large manufacturers who are currently producing transformers in the U.S. to evaluate offshore options. Faced with the prospect of wholesale changes to their production process, large investments and stranded assets, some manufacturers expect to strongly consider shifting production offshore at TSL 3 due to the increased labor expenses associated with the production processes required to make amorphous steel cores. In summary, at TSLs 1 and 2, DOE does not expect significant impacts on employment, but at TSL 3 or greater, which would require more investment, the impact is very uncertain.

Low-Voltage Dry-Type. Based on interviews with manufacturers, DOE estimates that there are approximately 2,200 employees associated with DOE-covered LVDT production. Approximately 75 percent of these employees are located outside of the U.S. Typically, high volume units are made in Mexico, taking advantage of lower labor rates, while custom designs are made closer to the manufacturer's customer base or R&D centers. DOE does not expect large changes in domestic employment to occur due to today's standard. Most production already occurs outside the U.S. and, by and large, manufacturers agreed that most design changes necessary to meet higher energy conservation standards would increase labor expenditures, not decrease them. If, however, small manufacturers began sourcing cores instead of manufacturing them in-house, there could be a small drop in employment at these firms. This employment would presumably transfer to the core makers, some of whom are domestic and some of whom are foreign. In summary, DOE does not expect significant changes to domestic LVDT industry employment levels as a result of today's standards. Higher TSLs may lead to small declines in domestic employment as more firms will be challenged with what amounts to clean-sheet redesigns. Facing the prospect of green field investments, these manufacturers may elect to make those investments in lower-labor cost countries.[67]

Medium-Voltage Dry-Type. Based on interviews with manufacturers, DOE estimates that there are approximately 1,850 employees associated with DOE-covered MVDT production. Approximately 75 percent of these employees are located domestically. With the exception of TSLs that require amorphous cores, manufacturers agreed that most design changes necessary to meet higher standards would increase labor expenditures, not decrease them, but current production equipment would not be stranded, mitigating the incentive to move production offshore. Corroborating this, the largest manufacturer and domestic employer in this market has indicated that the standard in this final rule, will not cause their company to reconsider production location. As such, DOE does not expect significant changes to domestic MVDT industry employment levels as a result of the standard in today's final rule. For TSLs that would require amorphous cores, DOE does anticipate significant changes to domestic MVDT industry employment levels.

c. Impacts on Manufacturing Capacity

Based on manufacturer interviews, DOE believes that there is significant excess capacity in the distribution transformer market. Shipments in the industry are well down from their peak in 2007, according to manufacturers. Therefore, DOE does not believe there would be any production capacity constraints at TSLs that do not require dramatic transitions to amorphous cores. For those TSLs that require amorphous cores in significant volumes, DOE believes there is potential for capacity constraints in the near term due to limitations on core steel availability. However, for the levels in today's rule, DOE does not foresee any capacity constraints.

d. Impacts on Subgroups of Manufacturers

Small manufacturers, niche equipment manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. Therefore, using average cost assumptions to develop an industry cash-flow estimate is inadequate to assess differential impacts among manufacturer subgroups. DOE considered small manufacturers as a subgroup in the MIA. For a discussion of the impacts on the small manufacturer subgroup, see the Regulatory Flexibility Analysis in section VI.B and chapter 12 of the final rule TSD.

e. Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of recent or impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory

[67] A green field investment is a form of foreign direct investment where a parent company starts a new venture in a foreign country by constructing new operational facilities from the ground up.

burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency. During previous stages of this rulemaking, DOE identified a number of requirements in addition to amended energy conservation standards for distribution transformers. The Department did not receive comments regarding cumulative regulatory burden issues for the NOPR. DOE addresses the full details of the cumulative regulatory burden analysis in chapter 12 of the final rule TSD.

3. National Impact Analysis

a. Significance of Energy Savings

For each TSL, DOE projected energy savings for transformers purchased in the 30-year period that begins in the year of compliance with amended standards (2016–2045). The savings are measured over the entire lifetime of products purchased in the 30-year period, which in the case of transformers extends through 2105. DOE quantified the energy savings attributable to each TSL as the difference in energy consumption between each standards case and the base case. Table V.28 presents the estimated energy savings for each considered TSL. The approach used is further described in section IV.G.[68]

TABLE V.28—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS FOR UNITS SOLD IN 2016–2045

	Trial standard level						
	1	2	3	4	5	6	7
	quads						
Liquid-immersed	0.92	1.56	1.76	3.31	3.30	4.09	7.01
Low-voltage dry-type	2.28	2.43	3.05	4.39	4.48	4.94	....
Medium-voltage dry-type	0.15	0.29	0.53	0.53	0.84	....	....

For this rulemaking, DOE undertook a sensitivity analysis using nine rather than 30 years of product shipments. The choice of a nine-year period is a proxy for the timeline in EPCA for the review of the energy conservation standard established in this final rule and potential revision of and compliance with a new standard for distribution transformers.[69] This timeframe may not be statistically relevant with regard to the product lifetime, product manufacturing cycles or other factors specific to distribution transformers. Thus, this information is presented for informational purposes only and is not indicative of any change in DOE's analytical methodology. The NES results based on a nine-year analytical period are presented in Table V.29. The impacts are counted over the lifetime of products purchased in 2016–2024.

TABLE V.29—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS FOR UNITS SOLD IN 2016–2024

	Trial standard level						
	1	2	3	4	5	6	7
	quads						
Liquid-immersed	0.25	0.42	0.47	0.90	0.90	1.12	1.93
Low-voltage dry-type	0.63	0.67	0.85	1.22	1.24	1.38	....
Medium-voltage dry-type	0.04	0.08	0.15	0.15	0.23	....	....

b. Net Present Value of Customer Costs and Benefits

DOE estimated the cumulative NPV of the total costs and savings for customers that would result from the TSLs considered for distribution transformers. In accordance with OMB's guidelines on regulatory analysis,[70] DOE calculated the NPV using both a 7-percent and a 3-percent real discount rate. The 7-percent rate is an estimate of the average before-tax rate of return on private capital in the U.S. economy, and reflects the returns on real estate and small business capital as well as corporate capital. This discount rate approximates the opportunity cost of capital in the private sector (OMB analysis has found the average rate of return on capital to be near this rate). The three-percent rate reflects the potential effects of standards on private consumption (e.g.,through higher prices for products and reduced purchases of energy). This rate represents the rate at which society discounts future consumption flows to

[68] Chapter 10 of the TSD presents tables that show the magnitude of the energy savings discounted at rates of 3 percent and 7 percent. Discounted energy savings represent a policy perspective in which energy savings realized farther in the future are less significant than energy savings realized in the nearer term.

[69] EPCA requires DOE to review its standards at least once every 6 years, and requires, for certain products, a 3 year period after any new standard is promulgated before compliance is required, except that in no case may any new standards be required within 6 years of the compliance date of the previous standards. While adding a 6-year review to the 3-year compliance period adds up to 9 years, DOE notes that it may undertake reviews at any time within the 6 year period and that the 3-year compliance date may yield to the 6-year backstop. A 9-year analysis period may not be appropriate given the variability that occurs in the timing of standards reviews and the fact that for some products, the compliance period is 5 years rather than 3 years.

[70] OMB Circular A–4, section E (Sept. 17, 2003). Available at: *http://www.whitehouse.gov/omb/circulars_a004_a-4*.

their present value. It can be approximated by the real rate of return on long-term government debt (i.e., yield on United States Treasury notes), which has averaged about 3 percent for the past 30 years.

Table V.30 shows the customer NPV results for each TSL considered. In each case, the impacts cover the lifetime of equipment purchased in 2016–2045.

TABLE V.30—NET PRESENT VALUE OF CUSTOMER BENEFITS FOR DISTRIBUTION TRANSFORMERS TRIAL STANDARD LEVELS FOR UNITS SOLD IN 2016–2045

	Discount rate %	Trial standard level						
		1	2	3	4	5	6	7
		billion 2011$						
Liquid-immersed	3	3.12	4.82	5.62	10.78	10.19	10.27	−8.50
	7	0.58	0.69	0.91	1.92	1.60	0.74	−12.97
Low-voltage dry-type	3	8.38	9.04	10.38	13.65	11.80	5.17	
	7	2.45	2.67	2.82	3.34	2.22	−1.92	
Medium-voltage dry-type	3	0.49	0.79	1.12	1.12	−0.20		
	7	0.13	0.17	0.12	0.12	−0.89		

The results shown in the table reflect the default equipment price trend, which uses constant prices. DOE conducted an NPV sensitivity analysis using alternative price trends. DOE developed one forecast in which prices decline after 2010, and one in which prices rise. The NPV results from the associated sensitivity cases are described in appendix 10–C of the final rule TSD.

The NPV results based on the aforementioned nine-year analytical period are presented in Table V.31. The impacts are counted over the lifetime of equipment purchased in 2016–2024. As mentioned previously, this information is presented for informational purposes only and is not indicative of any change in DOE's analytical methodology or decision criteria.

TABLE V.31—NET PRESENT VALUE OF CUSTOMER BENEFITS FOR DISTRIBUTION TRANSFORMERS TRIAL STANDARD LEVELS FOR UNITS SOLD IN 2016–2024

	Discount rate %	Trial standard level						
		1	2	3	4	5	6	7
		billion 2011$						
Liquid-Immersed	3	1.09	1.67	1.95	3.77	3.55	3.55	−3.49
	7	0.26	0.31	0.41	0.88	0.73	0.29	−6.56
Low-voltage dry-type	3	3.02	3.26	3.73	4.88	4.19	1.70	
	7	1.19	1.30	1.37	1.60	1.04	−1.04	
Medium-voltage dry-type	3	0.18	0.28	0.39	0.39	−0.11		
	7	0.07	0.08	0.05	0.05	−0.46		

c. Indirect Impacts on Employment

DOE expects energy conservation standards for distribution transformers to reduce energy costs for equipment owners, and the resulting net savings to be redirected to other forms of economic activity. Those shifts in spending and economic activity could affect the demand for labor. As described in section IV.J, DOE used an input/output model of the U.S. economy to estimate indirect employment impacts of the TSLs that DOE considered in this rulemaking. DOE understands that there are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Therefore, DOE generated results for near-term time frames (2016–2020), where these uncertainties are reduced.

The results suggest that today's standards are likely to have negligible impact on the net demand for labor in the economy. The net change in jobs is so small that it would be imperceptible in national labor statistics and might be offset by other, unanticipated effects on employment. Chapter 13 of the final rule TSD presents detailed results.

4. Impact on Utility or Performance of Equipment

DOE believes that the standards in today's rule will not lessen the utility or performance of distribution transformers.

5. Impact of Any Lessening of Competition

DOE has also considered any lessening of competition that is likely to result from new and amended standards. The Attorney General determines the impact, if any, of any lessening of competition likely to result from a proposed standard, and transmits such determination to the Secretary of Energy, together with an analysis of the nature and extent of such impact. (42 U.S.C. 6295(o)(2)(B)(i)(V) and (B)(ii))

To assist the Attorney General in making such a determination, DOE has provided the Department of Justice (DOJ) with copies of this notice and the TSD for review. DOE considered DOJ's comments on the proposed rule in preparing the final rule.

6. Need of the Nation to Conserve Energy

Enhanced energy efficiency, where economically justified, improves the Nation's energy security, strengthens the economy, and reduces the environmental impacts or costs of energy production. Reduced electricity demand due to energy conservation standards is also likely to reduce the cost of maintaining the reliability of the electricity system, particularly during peak-load periods. As a measure of this reduced demand, chapter 14 in the final rule TSD presents the estimated reduction in generating capacity in 2045 for the TSLs that DOE considered in this rulemaking.

Energy savings from standards for distribution transformers could also produce environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases associated with electricity production. Table V.32 provides DOE's estimate of cumulative CO_2, NO_X, and Hg emissions reductions projected to result from the TSLs considered in this rulemaking. DOE reports annual CO_2, NO_X, and Hg emissions reductions for each TSL in chapter 15 of the final rule TSD.

TABLE V.32—CUMULATIVE EMISSIONS REDUCTION ESTIMATED FOR DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS

	Trial standard level						
	1	2	3	4	5	6	7
Liquid-Immersed							
CO_2 (million metric tons)	82.2	143.1	156.5	274.6	273.4	321.8	501.8
NO_X (thousand tons)	69.3	120.6	131.8	231.1	230.1	270.8	421.9
SO_2 (thousand tons)	52.0	90.0	98.4	173.0	172.4	203.2	318.0
Hg (*tons*)	0.2	0.3	0.3	0.6	0.6	0.7	1.1
Low-Voltage Dry-Type							
CO_2 (million metric tons)	151.3	161.6	203.0	292.8	297.6	319.3	....
NO_X (thousand tons)	127.6	136.4	171.3	247.0	251.0	269.3	....
SO_2 (thousand tons)	110.1	117.6	147.8	213.2	216.7	232.4	....
Hg (*tons*)	0.4	0.4	0.5	0.8	0.8	0.8	....
Medium-Voltage Dry-Type							
CO_2 (million metric tons)	11.2	20.9	40.7	40.7	61.3	....	....
NO_X (thousand tons)	9.34	17.7	34.2	34.2	51.5	....	....
SO_2 (thousand tons)	7.06	13.29	25.65	25.65	38.69	....	....
Hg (*tons*)	0.02	0.04	0.10	0.10	0.14	....	....

As part of the analysis for this rule, DOE estimated monetary benefits likely to result from the reduced emissions of CO_2 and NO_X that DOE estimated for each of the TSLs considered. As discussed in section IV.M, DOE used values for the SCC developed by an interagency process. The four sets of SCC values resulting from that process (expressed in 2011$) are represented by $4.9/metric ton (the average value from a distribution that uses a 5-percent discount rate), $22.3/metric ton (the average value from a distribution that uses a 3-percent discount rate), $36.5/metric ton (the average value from a distribution that uses a 2.5-percent discount rate), and $67.6/metric ton (the 95th-percentile value from a distribution that uses a 3-percent discount rate). These values correspond to the value of emission reductions in 2011; the values for later years are higher due to increasing damages as the projected magnitude of climate change increases.

Table V.33 presents the global value of CO_2 emissions reductions at each TSL. For each of the four cases, DOE calculated a present value of the stream of annual values using the same discount rate as was used in the studies upon which the dollar-per-ton values are based. DOE calculated domestic values as a range from 7 percent to 23 percent of the global values, and these results are presented in chapter 16 of the final rule TSD.

TABLE V.33—ESTIMATES OF GLOBAL PRESENT VALUE OF CO_2 EMISSIONS REDUCTION UNDER DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS

TSL	5% discount rate, average *	3% discount rate, average *	2.5% discount rate, average *	3% discount rate, 95th percentile *
Million 2011$				
Liquid-Immersed				
1	259	1,390	2,377	4,230
2	454	2,428	4,151	7,390
3	494	2,649	4,530	8,060
4	855	4,609	7,891	14,024
5	851	4,588	7,855	13,960
6	991	5,366	9,195	16,325
7	1,515	8,266	14,190	25,144

TABLE V.33—ESTIMATES OF GLOBAL PRESENT VALUE OF CO_2 EMISSIONS REDUCTION UNDER DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS—Continued

TSL	5% discount rate, average *	3% discount rate, average *	2.5% discount rate, average *	3% discount rate, 95th percentile *
Low-Voltage Dry-Type				
1	450	2,470	4,245	7,512
2	480	2,637	4,532	8,020
3	603	3,313	5,694	10,075
4	870	4,779	8,214	14,535
5	884	4,857	8,348	14,771
6	949	5,211	8,956	15,847
Medium-Voltage Dry-Type				
1	35	188	321	571
2	65	350	599	1,065
3	126	680	1,164	2,067
4	126	680	1,164	2,067
5	190	1,024	1,755	3,117

DOE is well aware that scientific and economic knowledge about the contribution of CO_2 and other greenhouse gas (GHG) emissions to changes in the future global climate and the potential resulting damages to the world economy continues to evolve rapidly. Thus, any value placed on reducing CO_2 emissions in this rulemaking is subject to change. DOE, together with other Federal agencies, will continue to review various methodologies for estimating the monetary value of reductions in CO_2 and other GHG emissions. This ongoing review will consider the comments on this subject that are part of the public record for this and other rulemakings, as well as other methodological assumptions and issues. However, consistent with DOE's legal obligations, and taking into account the uncertainty involved with this particular issue, DOE has included in this final rule the most recent values and analyses resulting from the ongoing interagency review process.

DOE also estimated a range for the cumulative monetary value of the economic benefits associated with NO_X emissions reductions anticipated to result from amended standards for distribution transformers. The low and high dollar-per-ton values that DOE used are discussed in section IV.M. Table V.34 presents the cumulative present values for each TSL calculated using seven-percent and three-percent discount rates.

TABLE V.34—ESTIMATES OF PRESENT VALUE OF NO_X EMISSIONS REDUCTION UNDER DISTRIBUTION TRANSFORMER TRIAL STANDARD LEVELS

TSL	3% discount rate	7% discount rate
Million 2011$		
Liquid-Immersed		
1	13 to 138	6 to 57
2	24 to 242	10 to 100
3	26 to 263	11 to 109
4	44 to 454	18 to 185
5	44 to 452	18 to 184
6	51 to 525	21 to 211
7	78 to 799	31 to 314
Low-Voltage Dry-Type		
1	23 to 238	9 to 92
2	25 to 254	10 to 99
3	31 to 319	12 to 124
4	45 to 460	17 to 179
5	45 to 468	18 to 182
6	49 to 502	19 to 195
Medium-Voltage Dry-Type		
1	2 to 18	1 to 7
2	3 to 34	1 to 14
3	6 to 67	3 to 27
4	6 to 67	3 to 27
5	10 to 100	4 to 41

7. Summary of National Economic Impacts

The NPV of the monetized benefits associated with emissions reductions can be viewed as a complement to the NPV of the customer savings calculated for each TSL considered in this rulemaking. Table V.35 through Table V.37 present the NPV values that result from adding the estimates of the potential economic benefits resulting from reduced CO_2 and NO_X emissions in each of four valuation scenarios to the NPV of customer savings calculated for each TSL considered in this rulemaking, at both a seven-percent and three-percent discount rate. The CO_2 values used in the columns of each table correspond to the four sets of SCC values discussed above.

TABLE V.35—LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: NET PRESENT VALUE OF CUSTOMER SAVINGS COMBINED WITH NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS

TSL	Customer NPV at 3% Discount Rate added with:			
	SCC Value of $4.9/t CO_2* and Low Value for NO_X**	SCC Value of $22.3/t CO_2* and Medium Value for NO_X**	SCC Value of $36.5/t CO_2* and Medium Value for NO_X**	SCC Value of $67.6/t CO_2* and High Value for NO_X**
	Billion 2011$			
1	3.4	4.6	5.6	7.5
2	5.3	7.4	9.1	12.5
3	6.1	8.4	10.3	13.9
4	11.7	15.6	18.9	25.3
5	11.1	15.0	18.3	24.6
6	11.3	15.9	19.8	27.1
7	−6.9	0.2	6.1	17.4
TSL	Customer NPV at 7% Discount Rate added with:			
	SCC Value of $4.9/t CO_2* and Low Value for NO_X**	SCC Value of $22.3/t CO_2* and Medium Value for NO_X**	SCC Value of $36.5/t CO_2* and Medium Value for NO_X**	SCC Value of $67.6/t CO_2* and High Value for NO_X**
	Billion 2011$			
1	0.8	2.0	3.0	4.9
2	1.2	3.2	4.9	8.2
3	1.4	3.6	5.5	9.1
4	2.8	6.6	9.9	16.1
5	2.5	6.3	9.6	15.7
6	1.8	6.2	10.1	17.3
7	−11.4	−4.5	1.4	12.5

*These label values represent the global SCC in 2011, in 2011$. The present values have been calculated with scenario-consistent discount rates.

**Low Value corresponds to $450 per ton of NO_X emissions. Medium Value corresponds to $2,537 per ton of NO_X emissions. High Value corresponds to $4,623 per ton of NO_X emissions.

TABLE V.36—LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: NET PRESENT VALUE OF CUSTOMER SAVINGS COMBINED WITH NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS

TSL	Customer NPV at 3% Discount Rate added with:			
	SCC Value of $4.9/t CO_2* and Low Value for NO_X**	SCC Value of $22.3/t CO_2* and Medium Value for NO_X**	SCC Value of $36.5/t CO_2* and Medium Value for NO_X**	SCC Value of $67.6/t CO_2* and High Value for NO_X**
	Billion 2011$			
1	8.8	11.0	12.8	16.1
2	9.5	11.8	13.7	17.3
3	11.0	13.9	16.3	20.8
4	14.6	18.7	22.1	28.6
5	12.7	16.9	20.4	27.0
6	6.2	10.7	14.4	21.5
TSL	Customer NPV at 7% Discount Rate added with:			
	SCC Value of $4.9/t CO_2* and Low Value for NO_X**	SCC Value of $22.3/t CO_2* and Medium Value for NO_X**	SCC Value of $36.5/t CO_2* and Medium Value for NO_X**	SCC Value of $67.6/t CO_2* and High Value for NO_X**
	Billion 2011$			
1	2.9	5.0	6.7	10.0
2	3.2	5.4	7.3	10.8
3	3.4	6.2	8.6	13.0
4	4.2	8.2	11.7	18.1
5	3.1	7.2	10.7	17.2
6	−1.0	3.4	7.1	14.1

*These label values represent the global SCC in 2011, in 2011$. The present values have been calculated with scenario-consistent discount rates.

** Low Value corresponds to $450 per ton of NO_X emissions. Medium Value corresponds to $2,537 per ton of NO_X emissions. High Value corresponds to $4,623 per ton of NO_X emissions.

TABLE V.37—MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: NET PRESENT VALUE OF CUSTOMER SAVINGS COMBINED WITH NET PRESENT VALUE OF MONETIZED BENEFITS FROM CO_2 AND NO_X EMISSIONS REDUCTIONS

TSL	Customer NPV at 3% Discount Rate added with:			
	SCC Value of $4.9/t CO_2 * and Low Value for NO_X **	SCC Value of $22.3/t CO_2 * and Medium Value for NO_X **	SCC Value of $36.5/t CO_2 * and Medium Value for NO_X **	SCC Value of $67.6/t CO_2 * and High Value for NO_X **
Billion 2011$				
1	0.5	0.7	0.8	1.1
2	0.9	1.2	1.4	1.9
3	1.3	1.8	2.3	3.3
4	1.3	1.8	2.3	3.3
5	0.0	0.9	1.6	3.0
TSL	Customer NPV at 7% Discount Rate added with:			
	SCC Value of $4.9/t CO_2 * and Low Value for NO_X **	SCC Value of $22.3/t CO_2 * and Medium Value for NO_X **	SCC Value of $36.5/t CO_2 * and Medium Value for NO_X **	SCC Value of $67.6/t CO_2 * and High Value for NO_X **
	Billion 2011$			
1	0.2	0.3	0.5	0.7
2	0.2	0.5	0.8	1.2
3	0.2	0.8	1.3	2.2
4	0.2	0.8	1.3	2.2
5	−0.7	0.2	0.9	2.3

* These label values represent the global SCC in 2011, in 2011$. The present values have been calculated with scenario-consistent discount rates.

** Low Value corresponds to $450 per ton of NO_X emissions. Medium Value corresponds to $2,537 per ton of NO_X emissions. High Value corresponds to $4,623 per ton of NO_X emissions.

Although adding the value of customer savings to the values of emission reductions provides a valuable perspective, two issues should be considered. First, the national operating cost savings are domestic U.S. customer monetary savings that occur as a result of market transactions, while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and the SCC are performed with different methods that use quite different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2016–2045. The SCC values, on the other hand, reflect the present value of future climate-related impacts resulting from the emission of one metric ton of CO_2 in each year. These impacts continue well beyond 2100.

8. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VII))

Electrical steel is a critical consideration in the design and manufacture of distribution transformers, amounting for more than 60 percent of the distribution transformers mass in some designs. Rapid changes in the supply or pricing of certain grades can seriously hinder manufacturers' abilities to meet the market demand and, as a result, this rulemaking has extensively examined the effects of electrical steel supply and availability.

DOE's most important conclusion from this examination is that several energy efficiency levels in each design line are attainable only by using amorphous steel, which is currently produced by only one supplier in any significant volume and that supplier at present does not have enough capacity to supply the industry at all-amorphous standard levels. Several more energy efficiency levels are reachable with the top grades of conventional (grain-oriented) electrical steels, but this would result in distribution transformers that are unlikely to be cost-competitive with the often more-efficient amorphous units. As stated above, switching to amorphous steel is not practicable as there are availability concerns with amorphous steel.

Distribution transformers are also highly customized products. Manufacturers routinely build only one or a handful of units of a particular design and require flexibility with respect to construction materials to remain competitive. Setting a standard that either technologically or economically required amorphous material would both eliminate a large amount of design flexibility and expose the industry to enormous risk with respect to supply and pricing of core steel. For both reasons, DOE considered electrical steel availability to be a significant factor in determining which TSLs were economically justified.

C. Conclusion

When considering proposed standards, the new or amended energy conservation standard that DOE adopts for any type (or class) of covered equipment shall be designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy determines is technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) In determining whether a standard is economically justified, the Secretary must determine whether the benefits of the standard exceed its burdens to the greatest extent practicable, in light of the seven statutory factors discussed previously. (42 U.S.C. 6295(o)(2)(B)(i)) The new or amended standard must also ''result in significant conservation of energy.'' (42 U.S.C. 6295(o)(3)(B))

For today's rulemaking, DOE considered the impacts of standards at each TSL, beginning with the max-tech level, to determine whether that level was economically justified. Where the max-tech level was not justified, DOE then considered the next most efficient level and undertook the same evaluation until it reached the highest efficiency level that is technologically feasible, economically justified and saves a significant amount of energy.

To aid the reader in understanding the benefits and/or burdens of each TSL, tables in this section summarize the quantitative analytical results for each TSL, based on the assumptions and methodology discussed herein. The efficiency levels contained in each TSL are described in section V.A. In addition to the quantitative results presented in the tables, DOE also considers other burdens and benefits that affect economic justification. These include the impacts on identifiable subgroups of customers who may be disproportionately affected by a national standard, and impacts on employment. Section V.B.1 presents the estimated impacts of each TSL for the considered subgroup. DOE discusses the impacts on employment in transformer manufacturing in section V.B.2.b, and discusses the indirect employment impacts in section V.B.3.c.

1. Benefits and Burdens of Trial Standard Levels Considered for Liquid-Immersed Distribution Transformers

Table V.38 and Table V.39 summarize the quantitative impacts estimated for each TSL for liquid-immersed distribution transformers.

TABLE V.38—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
National Energy Savings *quads*.	0.92	1.56	1.76	3.31	3.30	4.09	7.01
NPV of Consumer Benefits *2011$ billion*							
3% discount rate	3.12	4.82	5.62	10.78	10.19	10.27	−8.50
7% discount rate	0.58	0.69	0.91	1.92	1.60	0.74	−12.97
Cumulative Emissions Reduction							
CO_2 (million metric tons).	82.2	143.1	156.5	274.6	273.4	321.8	501.8
NO_X (thousand tons).	69.3	120.6	131.8	231.1	230.1	270.8	421.9
SO_2 (thousand tons).	52.0	90.0	98.4	173.0	172.4	203.2	318.0
Hg (tons)	0.2	0.3	0.3	0.6	0.6	0.7	1.1
Value of Emissions Reduction							
CO_2 2011$ *million**.	259 to 4230	454 to 7390	494 to 8060	855 to 14024	851 to 13960	991 to 16325	1515 to 25144
NO_X − 3% discount rate *2011$ million*.	13 to 138	24 to 242	26 to 263	44 to 454	44 to 452	51 to 525	78 to 799
NO_X − 7% discount rate *2011$ million*.	6 to 57	10 to 100	11 to 109	18 to 185	18 to 184	21 to 211	31 to 314

* Range of the economic value of CO2 reductions is based on estimates of the global benefit of reduced CO2 emissions.

TABLE V.39—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Manufacturer Impacts							
Industry NPV 2011$ million.	527 to 552	466 to 508	462 to 506	389 to 478	382 to 474	358 to 487	181 to 576
Industry NPV % change.	(8.4) to (4.1)	(19.0) to (11.7)	(19.7) to (12.0)	(32.4) to (16.9)	(33.6) to (17.6)	(37.7) to (15.4)	(68.4) to 0.1
Consumer Mean LCC Savings *2011$*							
Design line 1	83	153	153	696	696	618	365
Design line 2	66	278	278	343	330	311	−579
Design line 3	2709	2407	3526	5527	5037	6942	4491
Design line 4	977	977	977	1212	3603	3603	4349
Design line 5	3668	3668	6852	10382	8616	12014	4619

TABLE V.39—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6	TSL 7
Consumer Median PBP *years*							
Design line 1	17.7	24.7	24.7	10.8	10.8	13.7	24.6
Design line 2	5.9	9.9	9.9	11.1	13.0	15.5	31.6
Design line 3	8.5	8.3	5.8	6.5	6.4	7.2	19.1
Design line 4	7.0	7.0	7.0	9.1	5.6	5.6	10.2
Design line 5	6.5	6.5	6.5	9.1	8.5	11.4	22.5
Distribution of Consumer LCC Impacts							
Design line 1							
Net Cost %	37.3	44.2	44.2	7.0	7.0	11.2	42.6
Net Benefit %	62.5	55.6	55.6	92.9	92.9	88.8	57.4
No Impact %	0.2	0.2	0.2	0.2	0.2	0.0	0.0
Design line 2							
Net Cost %	41.5	18.2	18.2	11.4	13.1	17.8	67.2
Net Benefit %	55.2	81.8	81.8	88.6	86.9	82.2	32.8
No Impact %	3.4	0.0	0.0	0.0	0.0	0.0	0.0
Design line 3							
Net Cost (%)	14.5	13.9	12.0	4.0	5.3	4.0	29.9
Net Benefit (%)	84.2	84.8	86.9	95.9	94.7	96.0	70.1
No Impact (%)	1.3	1.3	1.2	0.0	0.0	0.0	0.0
Design line 4							
Net Cost (%)	6.6	6.6	6.6	7.6	2.5	2.5	5.9
Net Benefit (%)	92.8	92.8	92.8	91.8	96.9	96.9	94.1
No Impact (%)	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Design line 5							
Net Cost (%)	30.5	30.5	19.9	9.8	14.8	9.1	41.9
Net Benefit (%)	69.1	69.1	80.0	90.2	85.2	91.0	58.1
No Impact (%)	0.4	0.4	0.1	0.0	0.0	0.0	0.0

First, DOE considered TSL 7, the most efficient level (max tech), which would save an estimated total of 7.01 quads of energy, an amount DOE considers significant. TSL 7 has an estimated NPV of customer benefit of −$12.97 billion using a 7 percent discount rate, and −$8.50 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 7 are 501.0 million metric tons of CO_2, 421.9 thousand tons of NO_X, 318.0 thousand tons of SO_2, and 1.1 tons of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 7 ranges from $1,515 million to $25,144 million.

At TSL 7, the average LCC impact ranges from −$579 for design line 2 to $4,619 for design line 5. The median PBP ranges from 31.6 years for design line 2 to 10.2 years for design line 4. The share of customers experiencing a net LCC benefit ranges from 32.8 percent for design line 2 to 70.1 percent for design line 3.

At TSL 7, the projected change in INPV ranges from a decrease of $394 million to an increase of $0.5 million. If the decrease of $394 million were to occur, TSL 7 could result in a net loss of 68.4 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 7, there is a risk of very large negative impacts on manufacturers due to the substantial capital and engineering costs they would incur and the market disruption associated with the likely transition to a market entirely served by amorphous steel. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 7 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity. DOE also has concerns about the competitive impact of TSL 7 on the electrical steel industry, as only one proven supplier of amorphous ribbon currently serves the U.S. market.

In view of the foregoing, DOE concludes that, at TSL 7 for liquid-immersed distribution transformers, the benefits of energy savings, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the potential multi-billion dollar negative net economic cost, the economic burden on customers as indicated by large PBPs, significant increases in installed cost, and the large percentage of customers who would experience LCC increases, the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 7. Consequently, DOE has concluded that TSL 7 is not economically justified.

Next, DOE considered TSL 6, which would save an estimated total of 4.09 quads of energy, an amount DOE considers significant. TSL 6 has an estimated NPV of customer benefit of $0.74 billion using a 7 percent discount rate, and $10.27 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 6 are 321.8 million metric tons of CO_2, 270.8 thousand tons of NO_X, 203.2 thousand tons of SO_2, and 0.7 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 6 ranges from $991 million to $16,325 million.

At TSL 6, the average LCC impact ranges from $311 for design line 2 to $12,014 for design line 5. The median PBP ranges from 5.6 years for design line 4 to 15.5 years for design line 2. The share of customers experiencing a net LCC benefit ranges from 82.2 percent for design line 2 to 96.9 percent for design line 4.

At TSL 6, the projected change in INPV ranges from a decrease of $217 million to a decrease of $89 million. If the decrease of $217 million were to occur, TSL 6 could result in a net loss of 37.7 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 6, DOE recognizes the risk of very large negative impacts on manufacturers due to the large capital and engineering costs and the market disruption associated with the likely transition to a market entirely served by amorphous steel. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing their transformers at the price points projected for TSL 6 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous transformer production capacity.

The energy savings under TSL 6 are achievable only by using amorphous steel, which only one supplier currently produces in any significant volume (annual production capacity of approximately 100,000 tons, the vast majority of which serves global demand). Thus, the current availability is far below the amount that would be required to meet the U.S. liquid-immersed transformer market demand of approximately 250,000 tons. Electrical steel is a critical consideration in the manufacture of distribution transformers, accounting for more than 60 percent of the transformer's mass in some designs. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. Therefore, setting a standard that requires amorphous material would expose the industry to enormous risk with respect to core steel supply. DOE also has concerns about the competitive impact of TSL 6 on the electrical steel industry. TSL 6 could jeopardize the ability of silicon steels to compete with amorphous metal, which risks upsetting competitive balance among steel suppliers and between them and their customers.

In view of the foregoing, DOE concludes that, at TSL 6 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 6. Consequently, DOE has concluded that TSL 6 is not economically justified.

Next, DOE considered TSL 5, which would save an estimated total of 3.30 quads of energy, an amount DOE considers significant. TSL 5 has an estimated NPV of customer benefit of $1.60 billion using a 7 percent discount rate, and $10.19 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 5 are 273.4 million metric tons of CO_2, 230.1 thousand tons of NO_X, 172.4 thousand tons of SO_2, and 0.6 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $851 million to $13,960 million.

At TSL 5, the average LCC impact ranges from $330 for design line 2 to$8,616 for design line 5. The median PBP ranges from 5.6 years for design line 4 to 13.0 years for design line 2. The share of customers experiencing a net LCC benefit ranges from 85.2 percent for design line 5 to 96.9 percent for design line 4.

At TSL 5, the projected change in INPV ranges from a decrease of $193 million to a decrease of $101 million. If the decrease of $193 million were to occur, TSL 5 could result in a net loss of 33.6 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 5, DOE recognizes the risk of very large negative impacts on manufacturers due to the large capital and engineering costs they would incur and the market disruption associated with the likely transition to a market almost entirely served by amorphous steel. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 5 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous core transformer production capacity.

Similar to TSL 6 as described above, the energy savings under TSL 5 are achievable only by using amorphous steel, which is currently available from only one supplier with significant volume and that supplier's production capacity of 100,000 tons is far below what would be required to meet market demand for electrical steel. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. Therefore, setting a standard that requires amorphous material would expose the industry to enormous risk with respect to core steel supply. TSL 5 could jeopardize the ability of silicon steels to compete with amorphous metal, which risks upsetting competitive balance among steel suppliers and between them and their customers.

In view of the foregoing, DOE concludes that, at TSL 5 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 5. Consequently, DOE has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated total of 3.31 quads of energy, an amount DOE considers significant. TSL 4 has an estimated NPV of customer benefit of $1.92 billion using a 7 percent discount rate, and $10.78 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 4 are 274.6 million metric tons of CO_2, 231.1 thousand tons of NO_X, 173.0 thousand tons of SO_2, and 0.6 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $855 million to $14,024 million.

At TSL 4, the average LCC impact ranges from $343 for design line 2 to $10,382 for design line 5. The median PBP ranges from 11.1 years for design line 2 to 6.5 years for design line 3. The share of customers experiencing a net LCC benefit ranges from 88.6 percent for design line 2 to 95.9 percent for design line 4.

At TSL 4, the projected change in INPV ranges from a decrease of $186 million to a decrease of $97 million. If the decrease of $186 million were to occur, TSL 4 could result in a net loss of 32.4 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 4, DOE recognizes the risk of large negative impacts on manufacturers due to the substantial capital and engineering costs they would incur. Additionally, if manufacturers' concerns about their customers rebuilding rather than replacing transformers at the price points projected for TSL 4 are realized, new transformer sales would suffer and make it even more difficult to recoup investments in amorphous core transformer production capacity.

DOE is also concerned that TSL 4, like the higher TSLs, will require amorphous steel to be competitive in many applications and at least a few design lines. As stated previously, the available supply of amorphous steel is well below the amount that would likely be required to meet the U.S. liquid-immersed distribution transformer market demand. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. Therefore, setting a standard that requires amorphous material would expose the industry to enormous risk with respect to core steel supply.

In addition, depending on how steel prices react to a standard, DOE believes TSL 4 could threaten the viability of a place in the market for conventional steel. Therefore, as with higher TSLs, DOE has concerns about the competitive impact of TSL 4 on the electrical steel manufacturing industry.

In view of the foregoing, DOE concludes that, at TSL 4 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 4. Consequently, DOE has concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated total of 1.76 quads of energy, an amount DOE considers significant. TSL 3 has an estimated NPV of customer benefit of $0.91 billion using a 7 percent discount rate, and $6.62 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 3 are 156.5 million metric tons of CO_2, 131.8 thousand tons of NO_X, 98.4 thousand tons of SO_2, and 0.3 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $494 million to $8,060 million.

At TSL 3, the average LCC impact ranges from $153 for design line 1 to $6,852 for design line 5. The median PBP ranges from 24.7 years for design line 1 to 5.8 years for design line 3. The share of customers experiencing a net LCC benefit ranges from 55.6 percent for design line 1 to 92.8 percent for design line 4.

At TSL 3, the projected change in INPV ranges from a decrease of $113 million to a decrease of $69 million. If the decrease of $113 million were to occur, TSL 3 could result in a net loss of 19.7 percent in INPV to manufacturers. At TSL 3, DOE recognizes the risk of large negative impacts on manufacturers due to the large capital and engineering costs they would incur.

Although the industry can manufacture liquid-immersed distribution transformers at TSL 3 from M3 or lower grade steels, the positive LCC and national impacts results described above are based on lowest first-cost designs, which include amorphous steel for all the design lines analyzed. As is the case with higher TSLs, DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. If manufacturers were to meet standards at TSL 3 using M3 or lower grade steels, DOE's analysis shows that the LCC impacts are negative.[71]

[71] DOE conducted a sensitivity analysis where LCC results are presented for liquid-immersed transformers without amorphous steel; see appendix 8–C in the final rule TSD.

In view of the foregoing, DOE concludes that, at TSL 3 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a large reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 3 in a cost-effective manner. Consequently, DOE has concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated total of 1.56 quads of energy, an amount DOE considers significant. TSL 2 has an estimated NPV of customer benefit of $0.69 billion using a 7-percent discount rate, and $4.82 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 2 are 143.1 million metric tons of CO_2, 120.6 thousand tons of NO_X, 90.0 thousand tons of SO_2, and 0.3 ton of Hg. The estimated monetary value of the CO_2 emissions reduction at TSL 2 ranges from $454 million to $7,390 million.

At TSL 2, the average LCC impact ranges from $153 for design line 1 to $3,668 for design line 5. The median PBP ranges from 24.7 years for design line 1 to 6.5 years for design line 5. The share of customers experiencing a net LCC benefit ranges from 55.6 percent for design line 1 to 92.8 percent for design line 4.

At TSL 2, the projected change in INPV ranges from a decrease of $110 million to a decrease of $67 million. If the decrease of $110 million were to occur, TSL 2 could result in a net loss of 19 percent in INPV to manufacturers of liquid-immersed distribution transformers. At TSL 2, DOE recognizes the risk of negative impacts on manufacturers due to the significant capital and engineering costs they would incur.

Although the industry can manufacture liquid-immersed transformers at TSL 2 from M3 or lower grade steels, the positive LCC and national impacts results described above are based on lowest first-cost designs, which include amorphous steel for design line 2. This design line represents approximately 44 percent of all liquid-immersed transformer shipments by MVA. Amorphous steel is currently available in significant volume from one supplier whose annual production capacity is below the amount that would be required to meet the demand for design line 2 under TSL 2. DOE is concerned that the current supplier, together with others that might enter the market, would not be able to increase production of amorphous steel rapidly enough to supply the amounts that would be needed by transformer manufacturers before 2015. If manufacturers were to meet standards at TSL 2 using M3 or lower grade steels, DOE's analysis shows that the LCC impacts would be negative.

In view of the foregoing, DOE concludes that, at TSL 2 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the capital and engineering costs that could result in a reduction in INPV for manufacturers, and the risk that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards at TSL 2 in a cost-effective manner. Consequently, DOE has concluded that TSL 2 is not economically justified.

Next, DOE considered TSL 1, which would save an estimated total of 0.92 quad of energy, an amount DOE considers significant. TSL 1 has an estimated NPV of customer benefit of $0.58 billion using a 7-percent discount rate, and $3.12 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 1 are 82.2 million metric tons of CO_2, 69.3 thousand tons of NO_X, 52.0 thousand tons of SO_2, and 0.2 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 1 ranges from $259 million to $4,230 million.

At TSL 1, the average LCC impact ranges from $83 for design line 2 to $3,668 for design line 5. The median PBP ranges from 17.7 years for design line 1 to 5.9 years for design line 2. The share of customers experiencing a net LCC benefit ranges from 55.2 percent for design line 2 to 92.8 percent for design line 4.

At TSL 1, the projected change in INPV ranges from a decrease of $48 million to a decrease of $24 million. If the decrease of $48 million were to occur, TSL 1 could result in a net loss of 8.4 percent in INPV to manufacturers of liquid-immersed distribution transformers.

The energy savings under TSL 1 are achievable without using amorphous steel. Therefore, the aforementioned risks that manufacturers may not be able to obtain the quantities of amorphous steel required to meet standards are not present under TSL 1.

After considering the analysis and weighing the benefits and the burdens, DOE has concluded that at TSL 1 for liquid-immersed distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average customer LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the emissions reductions would outweigh the potential reduction in INPV for manufacturers.

In view of the foregoing, DOE has concluded that TSL 1 would save a significant amount of energy and is technologically feasible and economically justified. For the above considerations, DOE today adopts the energy conservation standards for liquid-immersed distribution transformers at TSL 1. Table V.40 presents the energy conservation standards for liquid-immersed distribution transformers.

TABLE V.40—ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Electrical Efficiency by kVA and Equipment Class			
Equipment Class 1		Equipment Class 2	
kVA	%	kVA	%
10	98.70	15	98.65
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1000	99.43
667	99.52	1500	99.48
833	99.55	2000	99.51
		2500	99.53

2. Benefits and Burdens of Trial Standard Levels Considered for Low-Voltage Dry-Type Distribution Transformers

Table V.41 and Table V.42 summarize the quantitative impacts estimated for each TSL for low-voltage dry-type distribution transformers.

TABLE V.41—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
National Energy Savings (quads)	2.28	2.43	3.05	4.39	4.48	4.94
NPV of Customer Benefits (2011$ billion)						
3% discount rate	8.38	9.04	10.38	13.65	11.80	5.17
7% discount rate	2.45	2.67	2.82	3.34	2.22	-1.92
Cumulative Emissions Reduction						
CO_2 (million metric tons)	151.3	161.6	203.0	292.8	297.6	319.3
NO_X (thousand tons)	127.6	136.4	171.3	247.0	251.0	269.3
SO_2 (thousand tons)	110.1	117.6	147.8	213.2	216.7	232.4
Hg (tons)	0.4	0.4	0.5	0.8	0.8	0.8
Value of Emissions Reduction (2011$ million)						
CO_2*	450 to 7512	480 to 8020	603 to 10075	870 to 14535	884 to 14771	949 to 15847
NO_X − 3% discount rate	23 to 238	25 to 254	31 to 319	45 to 460	45 to 468	49 to 502
NO_X − 7% discount rate	9 to 92	10 to 99	12 to 124	17 to 179	18 to 182	19 to 195

* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.

TABLE V.42—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5	TSL 6
Manufacturer Impacts						
Industry NPV (2011$ million)	230 to 252	227 to 249	219 to 266	199 to 280	191 to 299	159 to 357
Industry NPV (% change)	(3.4) to 6.2	(4.7) to 5.0	(7.8) to 11.8	(16.4) to 17.8	(19.7) to 25.7	(33.1) to 50.1
Consumer Mean LCC Savings (2011$)						
Design line 6	0	0	325	148	148	−992
Design line 7	1526	1678	1838	2280	2280	212
Design line 8	2588	2588	2724	4261	−2938	−2938
Consumer Median PBP (years)						
Design line 6	0.0	0.0	12.4	15.7	15.7	31.7
Design line 7	3.9	3.6	4.1	6.3	6.3	16.8
Design line 8	7.7	7.7	11.3	10.1	22.5	22.5
Distribution of Consumer LCC Impacts						
Design line 6						
Net Cost (%)	0.0	0.0	16.5	37.8	37.8	96.6
Net Benefit (%)	0.0	0.0	83.5	62.2	62.2	3.4
No Impact (%)	100.0	100.0	0.0	0.0	0.0	0.0
Design line 7						
Net Cost (%)	1.5	1.3	1.7	3.3	3.3	45.6
Net Benefit (%)	98.4	98.7	98.3	96.7	96.7	54.4
No Impact (%)	0.1	0.1	0.0	0.0	0.0	0.0
Design line 8						
Net Cost (%)	4.7	4.7	13.3	9.0	79.3	79.3
Net Benefit (%)	95.3	95.3	86.7	91.0	20.7	20.7
No Impact (%)	0.0	0.0	0.0	0.0	0.0	0.0

First, DOE considered TSL 6, the most efficient level (max tech), which would save an estimated total of 4.94 quads of energy, an amount DOE considers significant. TSL 6 has an estimated NPV of customer benefit of −$1.92 billion using a 7-percent discount rate, and $5.17 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 6 are 319.3 million metric tons of CO_2, 269.3 thousand tons of NO_X, 232.4 thousand tons of SO_2, and 0.8 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 6 ranges from $949 million to $15,847 million.

At TSL 6, the average LCC impact ranges from −$2,938 for design line 8 to $212 for design line 7. The median PBP ranges from 31.7 years for design line 6 to 16.8 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 3.4 percent for design line 6 to 54.4 percent for design line 7.

At TSL 6, the projected change in INPV ranges from a decrease of $79 million to an increase of $119 million. If the decrease of $79 million occurs, TSL 6 could result in a net loss of 33.1 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 6, DOE recognizes the risk of very large negative impacts on the industry. TSL 6 would require manufacturers to scrap nearly all production assets and create transformer designs with which most, if not all, have no experience. DOE is concerned, in particular, about large impacts on small businesses, which may not be able to procure sufficient volume of amorphous steel at competitive prices, if at all.

In view of the foregoing, DOE concludes that, at TSL 6 for low-voltage dry-type distribution transformers, the benefits of energy savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the economic burden on customers (as indicated by negative average LCC savings, large PBPs, and the large percentage of customers who would experience LCC increases at design line 6 and design line 8), the potential for very large negative impacts on the manufacturers, and the potential burden on small manufacturers. Consequently, DOE has concluded that TSL 6 is not economically justified.

Next, DOE considered TSL 5, which would save an estimated total of 4.48 quads of energy, an amount DOE considers significant. TSL 5 has an estimated NPV of customer benefit of $2.22 billion using a 7 percent discount rate, and $11.80 billion using a 3 percent discount rate.

The cumulative emissions reductions at TSL 5 are 297.6 million metric tons of CO_2, 251.0 thousand tons of NO_X, 216.7 thousand tons of SO_2, and 0.8 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $884 million to $14,771 million.

At TSL 5, the average LCC impact ranges from −$2,938 for design line 8 to $2,280 for design line 7. The median PBP ranges from 22.5 years for design line 8 to 6.3 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 20.7 percent for design line 8 to 96.7 percent for design line 7.

At TSL 5, the projected change in INPV ranges from a decrease of $47 million to an increase of $61 million. If the decrease of $47 million occurs, TSL 5 could result in a net loss of 19.7 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 5, DOE recognizes the risk of very large negative impacts on the industry. TSL 5 would require manufacturers to scrap nearly all production assets and create transformer designs with which most, if not all, have no experience. DOE is concerned, in particular, about large impacts on small businesses, which may not be able to procure sufficient volume of amorphous steel at competitive prices, if at all.

In view of the foregoing, DOE concludes that, at TSL 5 for low-voltage dry-type distribution transformers, the benefits of energy savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the economic burden on customers at design line 8 (as indicated by negative average LCC savings, large PBPs, and the large percentage of customers who would experience LCC increases), the potential for very large negative impacts on the manufacturers, and the potential burden on small manufacturers. Consequently, DOE has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated total of 4.39 quads of energy, an amount DOE considers significant. TSL 4 has an estimated NPV of customer benefit of $3.34 billion using a 7-percent discount rate, and $13.65 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 4 are 292.8 million metric tons of CO_2, 247.0 thousand tons of NO_X, 213.2 thousand tons of SO_2, and 0.8 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $870 million to $14,535 million.

At TSL 4, the average LCC impact ranges from $148 for design line 6 to $4,261 for design line 8. The median PBP ranges from 15.7 years for design line 6 to 6.3 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 62.2 percent for design line 6 to 96.7 percent for design line 7.

At TSL 4, the projected change in INPV ranges from a decrease of $39 million to an increase of $42 million. If the decrease of $39 million occurs, TSL 4 could result in a net loss of 16.4 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 4, DOE recognizes the risk of very large negative impacts on the industry. As with the higher TSLs, TSL 4 would require manufacturers to scrap nearly all production assets and create transformer designs with which most, if not all, have no experience. DOE is concerned, in particular, about large impacts on small businesses, which may not be able to procure sufficient volume of amorphous steel at competitive prices, if at all.

Additionally, TSL 4 requires significant investment in advanced core construction equipment such are step-lap mitering machines or wound core production lines, as butt lap designs, even with high-grade designs, are unlikely to comply. Given their more limited engineering resources and capital, small businesses may find it difficult to make these designs at competitive prices and may have to exit the market. At the same time, however, those small manufacturers may be able to source their cores—and many are doing so to a significant extent currently—which could mitigate impacts.

In view of the forgoing, DOE concludes that, at TSL 4 for low-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the potential for very large negative impacts on the manufacturers, and the potential burden on small manufacturers. Consequently, DOE has concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated total of 3.05 quads of energy, an amount DOE considers significant. TSL 3 has an estimated NPV of customer benefit of $2.82 billion using a 7-percent discount rate, and $10.38 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 3 are 203.0 million metric tons of CO_2, 171.3 thousand tons of NO_X, 147.8 thousand tons of SO_2, and 0.5 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $603 million to $10,075 million.

At TSL 3, the average LCC impact ranges from $325 for design line 6 to $2,724 for design line 8. The median PBP ranges from 12.4 years for design line 6 to 4.1 years for design line 7. The share of customers experiencing a net LCC benefit ranges from 83.5 percent for design line 6 to 98.3 percent for design line 7.

At TSL 3, the projected change in INPV ranges from a decrease of $19 million to an increase of $28 million. If the decrease of $19 million occurs, TSL 3 could result in a net loss of 7.8 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 3, DOE recognizes the risk of negative impacts on the industry, particularly the small manufacturers. While TSL 3 could likely be met with M4 steel, DOE's analysis shows that this design option is at the edge of its technical feasibility at the efficiency levels comprised by TSL 3. Although these levels could be met with M3 or better steels, DOE is concerned that a significant number of small manufacturers would be unable to acquire these steels in sufficient supply and quality to compete.

Additionally, TSL 3 requires significant investment in advanced core construction equipment such are step-lap mitering machines or wound core production lines, as butt lap designs, even with high-grade designs, are unlikely to comply. Given their more limited engineering resources and capital, small businesses may find it difficult to make these designs at competitive prices and may have to exit the market. At the same time, however, those small manufacturers may be able to source their cores—and many are doing so to a significant extent currently—which could mitigate impacts.

In view of the foregoing, DOE concludes that, at TSL 3 for low-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive average LCC savings, generating capacity reductions, emission reductions, and the estimated monetary value of the CO_2 emissions reductions would be outweighed by the risk of negative impacts on the industry, particularly the small manufacturers. Consequently, DOE has concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated total of 2.43 quads of energy, an amount DOE considers significant. TSL 2 has an estimated NPV of customer benefit of $2.67 billion using a 7-percent discount rate, and $9.04 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 2 are 161.6 million metric tons of CO_2, 136.4 thousand tons of NO_X, 117.6 thousand tons of SO_2, and 0.4 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 2 ranges from $480 million to $8,020 million.

At TSL 2, the average LCC impact ranges from $0 for design line 6 to $2,588 for design line 8. The median PBP ranges from 7.7 years for design line 8 to 0 years for design line 6. The share of customers experiencing a net LCC benefit ranges from 0 percent for design line 6 to 98.7 percent for design line 7.

At TSL 2, the projected change in INPV ranges from a decrease of $11 million to an increase of $12 million. If the decrease of $11 million occurs, TSL 2 could result in a net loss of 4.7 percent in INPV to manufacturers of low-voltage dry-type distribution transformers. At TSL 2, manufacturers have the option of continuing to produce transformers using butt-lap technology, investing in mitering equipment, or sourcing their cores. Furthermore, since TSL 2 represents EL 3 for DL 7 and EL 2 for DL 8 (and baseline for DL 6), manufacturers may benefit from being able to standardize to NEMA Premium® levels for low-voltage dry-type distribution transformers.

After considering the analysis and weighing the benefits and the burdens, DOE has concluded that at TSL 2 for low-voltage dry-type distribution transformers, the benefits of energy savings, NPV of customer benefit, positive customer LCC impacts, emissions reductions and the estimated monetary value of the emissions reductions would outweigh the risk of small negative impacts on the manufacturers. In particular, DOE has concluded that TSL 2 would save a significant amount of energy and is technologically feasible and economically justified. For the reasons given above, DOE today adopts the energy conservation standards for low-voltage dry-type distribution transformers at TSL 2. Table V.43 presents the energy conservation standards for low-voltage dry-type distribution transformers.

TABLE V.43—ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Electrical Efficiency by kVA and Equipment Class			
Equipment Class 3		Equipment Class 4	
kVA	%	kVA	%
15	97.70	15	97.89
25	98.00	30	98.23
37.5	98.20	45	98.40
50	98.30	75	98.60
75	98.50	112.5	98.74
100	98.60	150	98.83
167	98.70	225	98.94
250	98.80	300	99.02
333	98.90	500	99.14
		750	99.23
		1000	99.28

3. Benefits and Burdens of Trial Standard Levels Considered for Medium-Voltage Dry-Type Distribution Transformers

Table V.44 and Table V.45 summarize the quantitative impacts estimated for each TSL for medium-voltage dry-type distribution transformers.

TABLE V.44—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
National Energy Savings (*quads*)	0.15	0.29	0.53	0.53	0.84
NPV of Consumer Benefits (*2011$ billion*)					
3% discount rate	0.49	0.79	1.12	1.12	−0.20
7% discount rate	0.13	0.17	0.12	0.12	−0.89
Cumulative Emissions Reduction					
CO_2 (million metric tons)	11.2	20.9	40.7	40.7	61.3
NO_X (thousand tons)	9.34	17.7	34.2	34.2	51.5
SO_2 (thousand tons)	7.1	13.3	25.7	25.7	38.7
Hg (*tons*)	0.02	0.04	0.10	0.10	0.14
Value of Emissions Reduction (2011$ million)					
CO_2 *	35 to 571	65 to 1065	126 to 2067	126 to 2067	190 to 3117
NO_X − 3% discount rate	2 to 18	3 to 34	6 to 67	6 to 67	10 to 100
NO_X − 7% discount rate	1 to 7	1 to 14	3 to 27	3 to 27	4 to 41

* Range of the economic value of CO_2 reductions is based on estimates of the global benefit of reduced CO_2 emissions.

TABLE V.45—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (2011$ million)	67 to 69	66 to 72	58 to 74	58 to 74	35 to 82
Industry NPV (% change)	(2.0) to 1.0	(4.2) to 4.4	(15.6) to 8.3	(15.5) to 8.2	(49.7) to 18.7
Consumer Mean LCC Savings (2011$)					
Design line 9	787	787	1514	1514	−299
Design line 10	4604	4455	4455	4455	−14727
Design line 11	996	996	1849	1849	−4166
Design line 12	4537	6790	8594	8594	−14496
Design line 13A	−27	−27	311	−1019	−12053
Design line 13B	2494	4346	4346	4346	−6823
Consumer Median PBP (years)					
Design line 9	2.6	2.6	6.1	6.1	18.5
Design line 10	1.1	8.6	8.6	8.6	27.5
Design line 11	10.6	10.6	13.6	13.6	24.1
Design line 12	6.0	8.5	12.3	12.3	24.7
Design line 13A	16.1	16.1	16.2	20	35.3
Design line 13B	4.5	12.2	12.2	12.2	20.6
Distribution of Consumer LCC Impacts					
Design line 9					
Net Cost (%)	3.6	3.6	5.9	5.9	57.4
Net Benefit (%)	83.2	83.2	94.1	94.1	42.6
No Impact (%)	13.3	13.3	0.0	0.0	0.0
Design line 10					
Net Cost (%)	3.6	3.6	5.9	5.9	57.4
Net Benefit (%)	83.2	83.2	94.1	94.1	42.6
No Impact (%)	13.3	13.3	0.0	0.0	0.0
Design line 11					
Net Cost (%)	21.9	21.9	25.9	25.9	82.7
Net Benefit (%)	78.1	78.1	74.1	74.1	17.4
No Impact (%)	0.0	0.0	0.0	0.0	0.0

TABLE V.45—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS: MANUFACTURER AND CONSUMER IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Design line 12					
Net Cost (%)	7.1	7.6	17.1	17.1	85.4
Net Benefit (%)	92.9	92.4	82.9	82.9	14.6
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Design line 13A					
Net Cost (%)	54.2	54.2	45.5	66.3	98.5
Net Benefit (%)	45.8	45.8	54.5	33.7	1.5
No Impact (%)	0.0	0.0	0.0	0.0	0.0
Design line 13B					
Net Cost (%)	30.5	27.3	27.3	27.3	70.4
Net Benefit (%)	69.3	72.7	72.7	72.7	29.6
No Impact (%)	0.2	0.0	0.0	0.0	0.0

First, DOE considered TSL 5, the most efficient level (max tech), which would save an estimated total of 0.84 quad of energy, an amount DOE considers significant. TSL 5 has an estimated NPV of customer benefit of −$0.89 billion using a 7-percent discount rate, and −$0.20 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 5 are 61.3 million metric tons of CO_2, 51.5 thousand tons of NO_X, 38.7 thousand tons of SO_2, and 0.14 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 5 ranges from $190 million to $3,117 million.

At TSL 5, the average LCC impact ranges from −$14,727 for design line 10 to −299 for design line 9. The median PBP ranges from 35.3 years for design line 13A to 18.5 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 1.5 percent for design line 13A to 42.6 percent for design line 9.

At TSL 5, the projected change in INPV ranges from a decrease of $34 million to an increase of $13 million. If the decrease of $34 million occurs, TSL 5 could result in a net loss of 49.7 percent in INPV to manufacturers of medium-voltage dry-type distribution transformers. At TSL 5, DOE recognizes the risk of very large negative impacts on industry because they would likely be forced to move to amorphous core steel technology, with which there is no experience in this market.[72]

In view of the foregoing, DOE concludes that, at TSL 5 for medium-voltage dry-type distribution transformers, the benefits of energy savings, generating capacity reductions, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the negative NPV of customer benefit, the economic burden on customers (as indicated by negative average LCC savings, large PBPs, and the large percentage of customers who would experience LCC increases), and the risk of very large negative impacts on the manufacturers. Consequently, DOE has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated total of 0.53 quad of energy, an amount DOE considers significant. TSL 4 has an estimated NPV of customer benefit of $0.12 billion using a 7-percent discount rate, and $1.12 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 4 are 40.7 million metric tons of CO_2, 34.2 thousand tons of NO_X, 25.7 thousand tons of SO_2, and 0.1 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 4 ranges from $126 million to $2,067 million.

At TSL 4, the average LCC impact ranges from −$1019 for design line 13A to $8,594 for design line 12. The median PBP ranges from 20.0 years for design line 13B to 6.1 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 33.7 percent for design line 13A to 94.1 percent for design line 9.

At TSL 4, the projected change in INPV ranges from a decrease of $11 million to an increase of $6 million. If the decrease of $11 million occurs, TSL 4 could result in a net loss of 15.5 percent in INPV to manufacturers of medium-voltage dry-type distribution transformers. At TSL 4, DOE recognizes the risk of very large negative impacts on most manufacturers in the industry who have little experience with the steels that would be required. Small businesses, in particular, with limited engineering resources, may not be able to convert their lines to employ thinner steels and may be disadvantaged with respect to access to key materials, including Hi-B steels.

In view of the foregoing, DOE concludes that, at TSL 4 for medium-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive impacts on consumers (as indicated by positive average LCC savings, favorable PBPs, and the large percentage of customers who would experience LCC benefits), emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the risk of very large negative impacts on the manufacturers, particularly small businesses. Consequently, DOE has concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated total of 0.53 quad of energy, an amount DOE considers significant. TSL 3 has an estimated NPV of customer benefit of $0.12 billion using a 7-percent discount rate, and $1.12 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 3 are 40.7 million metric tons of CO_2, 34.2 thousand tons of NO_X, 25.7 thousand tons of SO_2, and 0.1 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 3 ranges from $126 million to $2,067 million.

At TSL 3, the average LCC impact ranges from $311 for design line 13A to $8594 for design line 12. The median

[72] See section IV.I.5.a for further detail.

PBP ranges from 16.2 years for design line 13A to 6.1 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 54.5 percent for design line 13A to 94.1 percent for design line 9.

At TSL 3, the projected change in INPV ranges from a decrease of $11 million to an increase of $6 million. If the decrease of $11 million occurs, TSL 3 could result in a net loss of 15.6 percent in INPV to manufacturers of medium-voltage dry-type transformers. At TSL 3, DOE recognizes the risk of large negative impacts on most manufacturers in the industry who have little experience with the steels that would be required. As with TSL 4, small businesses, in particular, with limited engineering resources, may not be able to convert their lines to employ thinner steels and may be disadvantaged with respect to access to key materials, including Hi-B steels.

In view of the foregoing, DOE concludes that, at TSL 3 for medium-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive impacts on consumers (as indicated by positive average LCC savings, favorable PBPs, and the large percentage of customers who would experience LCC benefits), emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the risk of large negative impacts on the manufacturers, particularly small businesses. Consequently, DOE has concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated total of 0.29 quads of energy, an amount DOE considers significant. TSL 2 has an estimated NPV of customer benefit of $0.17 billion using a 7-percent discount rate, and $0.79 billion using a 3-percent discount rate.

The cumulative emissions reductions at TSL 2 are 20.9 million metric tons of CO_2, 17.7 thousand tons of NO_X, 13.3 thousand tons of SO_2, and 0.04 ton of Hg. The estimated monetary value of the CO_2 emissions reductions at TSL 2 ranges from $65 million to $1,065 million.

At TSL 2, the average LCC impact ranges from $−27 for design line 13A to $6,790 for design line 12. The median PBP ranges from 16.1 years for design line 13A to 2.6 years for design line 9. The share of customers experiencing a net LCC benefit ranges from 45.8 percent for design line 13A to 92.4 percent for design line 12.

At TSL 2, the projected change in INPV ranges from a decrease of $3 million to an increase of $3 million. If the decrease of $3 million occurs, TSL 2 could result in a net loss of 4.2 percent in INPV to manufacturers of medium-voltage dry-type distribution transformers. At TSL 2, DOE recognizes the risk of small negative impacts if manufacturers are unable to recoup investments made to meet the standard.

After considering the analysis and weighing the benefits and the burdens, DOE has concluded that at TSL 2 for medium-voltage dry-type distribution transformers, the benefits of energy savings, positive NPV of customer benefit, positive impacts on consumers (as indicated by positive average LCC savings for five of the six design lines, favorable PBPs, and the large percentage of customers who would experience LCC benefits), emission reductions, and the estimated monetary value of the emissions reductions would outweigh the risk of small negative impacts if manufacturers are unable to recoup investments made to meet the standard. In particular, DOE has concluded that TSL 2 would save a significant amount of energy and is technologically feasible and economically justified. In addition, DOE notes that TSL 2 corresponds to the standards that were agreed to by the DOE Efficiency and Renewables Advisory Committee (ERAC) subcommittee, as described in section II.B.2. Based on the above considerations, DOE today adopts the energy conservation standards for medium-voltage dry-type distribution transformers at TSL 2. Table V.46 presents the energy conservation standards for medium-voltage dry-type distribution transformers.

TABLE V.46—ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Electrical efficiency by kVA and equipment class											
Equipment class 5		Equipment class 6		Equipment class 7		Equipment class 8		Equipment class 9		Equipment class 10	
kVA	%	kVA	%	kVA	%	kVA	%	kVA	%	kVA	%
15	98.10	15	97.50	15	97.86	15	97.18	....	....	....	....
25	98.33	30	97.90	25	98.12	30	97.63	....	....	....	....
37.5	98.49	45	98.10	37.5	98.30	45	97.86	....	....	....	....
50	98.60	75	98.33	50	98.42	75	98.13	....	....	....	....
75	98.73	112.5	98.52	75	98.57	112.5	98.36	75	98.53	....	....
100	98.82	150	98.65	100	98.67	150	98.51	100	98.63	....	....
167	98.96	225	98.82	167	98.83	225	98.69	167	98.80	225	98.57
250	99.07	300	98.93	250	98.95	300	98.81	250	98.91	300	98.69
333	99.14	500	99.09	333	99.03	500	98.99	333	98.99	500	98.89
500	99.22	750	99.21	500	99.12	750	99.12	500	99.09	750	99.02
667	99.27	1000	99.28	667	99.18	1000	99.20	667	99.15	1000	99.11
833	99.31	1500	99.37	833	99.23	1500	99.30	833	99.20	1500	99.21
		2000	99.43			2000	99.36			2000	99.28
....	....	2500	99.47			2500	99.41			2500	99.33

4. Summary of Benefits and Costs (Annualized) of Today's Standards

The benefits and costs of today's standards can also be expressed in terms of annualized values. The annualized monetary values are the sum of: (1) the annualized national economic value of the benefits from operating products that meet today's standards (consisting primarily of operating cost savings from using less energy, minus increases in equipment purchase costs, which is another way of representing customer NPV); and (2) the monetary value of the benefits of emission reductions, including CO_2 emission reductions.[73] The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 developed by a recent interagency process.

Although combining the values of operating savings and CO_2 reductions provides a useful perspective, two issues should be considered. First, the national operating savings are domestic U.S. customer monetary savings that occur as a result of market transactions while the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and SCC are performed with different methods that use different time frames for analysis. The national operating cost savings is measured for the lifetime of products shipped in 2016–2045. The SCC values, on the other hand, reflect the present value of future climate-related impacts resulting from the emission of one metric ton of CO_2 in each year. These impacts continue well beyond 2100.

Table V.47 shows the annualized values for today's standards for distribution transformers. The results for the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs (other than CO_2 reduction, for which DOE used a 3-percent discount rate along with the SCC series corresponding to a value of $22.3/ton in 2011), the cost of the standards in today's rule is $266 million per year in increased equipment costs, while the benefits are $581 million per year in reduced equipment operating costs, $237 million in CO_2 reductions, and $8.60 million in reduced NO_X emissions. In this case, the net benefit amounts to $561 million per year. Using a 3-percent discount rate for all benefits and costs (and the SCC series corresponding to a value of $22.3/ton in 2011), the cost of the standards in today's rule is $282 million per year in increased equipment costs, while the benefits are $983 million per year in reduced operating costs, $237 million in CO_2 reductions, and $12.67 million in reduced NO_X emissions. In this case, the net benefit amounts to $950 million per year.

TABLE V.47—ANNUALIZED BENEFITS AND COSTS OF STANDARDS FOR DISTRIBUTION TRANSFORMERS SOLD IN 2016–2045

	Discount rate %	Million 2011$/year		
		Primary estimate*	Low net benefits estimate*	High net benefits estimate*
Benefits				
Operating cost savings	7%	581	559	590.
	3%	983	930	1003.
CO_2 reduction monetized value ($4.9/t case)**	5%	57.7	57.7	57.7.
CO_2 reduction monetized value ($22.3/t case)**	3%	237	237	237.
CO_2 reduction monetized value ($36.5/t case)**	2.5%	377	377	377.
CO_2 reduction monetized value ($67.6/t case)**	3%	721	721	721.
NO_X reduction monetized value ($2,591/ton)**	7%	8.60	8.60	8.60.
	3%	12.67	12.67	12.67.
Total benefits†	7% plus CO_2 range	648 to 1311	625 to 1288	656 to 1319.
	7%	827	805	836.
	3% plus CO_2 range	1053 to 1716	1000 to 1663	1074 to 1737.
	3%	1233	1179	1253.
Costs				
Incremental equipment costs	7%	266	300	257.
	3%	282	325	271.
Net Benefits				
Total†	7% plus CO_2 range	381 to 1044	325 to 988	400 to 1063.
	7%	561	504	579.
	3% plus CO_2 range	771 to 1434	675 to 1338	803 to 1466.
	3%	950	854	982.

* The Primary, Low Net Benefits, and High Net Benefits Estimates utilize forecasts of energy prices from the *AEO 2012* reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect no change in the Primary estimate, rising product prices in the Low Net Benefits estimate, and declining product prices in the High Net Benefits estimate.

** The CO_2 values represent global monetized values of the SCC, in 2011$, in 2011 under several scenarios. The values of $4.9, $22.3, and $36.5 per metric ton are the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The value of $67.6/t represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series used by DOE incorporate an escalation factor. The value for NO_X (in 2011$) is the average of the low and high values used in DOE's analysis.

† Total Benefits for both the 3% and 7% cases are derived using the series corresponding to SCC value of $22.3/t. In the rows labeled "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

[73] DOE used a two-step calculation process to convert the time-series of costs and benefits into annualized values. First, DOE calculated a present value in 2012, the year used for discounting the NPV of total consumer costs and savings, for the time-series of costs and benefits using discount rates of 3 and 7 percent for all costs and benefits except for the value of CO_2 reductions. For the latter, DOE used a range of discount rates, as shown in Table V.47. From the present value, DOE then calculated the fixed annual payment over a 30-year period that yields the same present value. The fixed annual payment is the annualized value. Although DOE calculated annualized values, this does not imply that the time-series of cost and benefits from which the annualized values were determined would be a steady stream of payments.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Orders 12866 and 13563

Section 1(b)(1) of Executive Order 12866, ''Regulatory Planning and Review,'' 58 FR 51735 (Oct. 4, 1993), requires each agency to identify the problem that it intends to address, including, where applicable, the failures of private markets or public institutions that warrant new agency action, as well as to assess the significance of that problem. The problems addressed by today's standards are as follows:

(1) There is a lack of consumer information and/or information processing capability about energy efficiency opportunities in the commercial equipment market.

(2) There is asymmetric information (one party to a transaction has more and better information than the other) and/or high transactions costs (costs of gathering information and effecting exchanges of goods and services).

(3) There are some external benefits resulting from improved energy efficiency of distribution transformers that are not captured by the users of such equipment. These benefits include externalities related to environmental protection and energy security that are not reflected in energy prices, such as reduced emissions of greenhouse gases.

The specific market failure that the energy conservation standard addresses for distribution transformers is that a substantial portion of distribution transformer purchasers are not evaluating the cost of transformer losses when they make distribution transformer purchase decisions. Consequently, distribution transformers are being purchased that do not provide the minimum LCC to the equipment owners.

For distribution transformers, the Institute of Electronic and Electrical Engineers Inc. (IEEE) has documented voluntary guidelines for the economic evaluation of distribution transformer losses, IEEE PC57.12.33/D8. These guidelines document economic evaluation methods for distribution transformers that are common practice in the utility industry. But while economic evaluation of transformer losses is common, it is not a universal practice. DOE collected information during the course of the previous energy conservation standard rulemaking to estimate the extent to which distribution transformer purchases are evaluated. Data received from NEMA indicated that these guidelines or similar criteria are applied to approximately 75 percent of liquid-immersed distribution transformer purchases, 50 percent of small capacity medium-voltage dry-type transformer purchases, and 80 percent of large capacity medium-voltage dry-type transformer purchases. Therefore, 25 percent, 50 percent, and 20 percent of such purchases in these segments do not employ economic evaluation of transformer losses. These are the portions of the distribution transformer market in which there is market failure. Today's energy conservation standards would eliminate from the market those distribution transformers designs that are purchased on a purely minimum first cost basis, but which would not likely be purchased by equipment buyers when the economic value of equipment losses are properly evaluated.

In addition, DOE has determined that today's regulatory action is an ''economically significant regulatory action'' under section 3(f)(1) of Executive Order 12866. Accordingly, section 6(a)(3) of the Executive Order requires that DOE prepare a regulatory impact analysis (RIA) on today's rule and that the Office of Information and Regulatory Affairs (OIRA) in the Office of Management and Budget (OMB) review this rule. DOE presented to OIRA for review the draft rule and other documents prepared for this rulemaking, including the RIA, and has included these documents in the rulemaking record. The assessments prepared pursuant to Executive Order 12866 can be found in the technical support document for this rulemaking.

DOE has also reviewed this regulation pursuant to Executive Order 13563, issued on January 18, 2011 (76 FR 3281, Jan. 21, 2011). EO 13563 is supplemental to and explicitly reaffirms the principles, structures, and definitions governing regulatory review established in Executive Order 12866. To the extent permitted by law, agencies are required by Executive Order 13563 to: (1) Propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

DOE emphasizes as well that Executive Order 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, the Office of Information and Regulatory Affairs has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. For the reasons stated in the preamble, DOE believes that today's final rule is consistent with these principles, including the requirement that, to the extent permitted by law, benefits justify costs and that net benefits are maximized.

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis (IRFA) for any rule that by law must be proposed for public comment, and a final regulatory flexibility analysis (FRFA) for any such rule that an agency adopts as a final rule, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by Executive Order 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (August 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process. 68 FR 7990. DOE has made its procedures and policies available on the Office of the General Counsel's Web site (*http://energy.gov/gc/office-general-counsel*). DOE reviewed the February 2012 NOPR and today's final rule under the provisions of the Regulatory Flexibility Act and the procedures and policies published on February 19, 2003.

As presented and discussed in the following sections, the FRFA describes potential impacts on small manufacturers associated with the required product and capital conversion costs at each TSL and discusses alternatives that could minimize these impacts. Chapter 12 of the TSD contains more information about the impact of this rulemaking on manufacturers.

1. Statement of the Need for, and Objectives of, the Rule

The reasons why DOE is establishing the standards in today's final rule and the objectives of these standards are provided elsewhere in the preamble and not repeated here.

2. Summary of and Responses to the Significant Issues Raised by the Public Comments, and a Statement of Any Changes Made as a Result of Such Comments

This FRFA incorporates the IRFA and public comments received on the IRFA and the economic impacts of the rule. DOE provides responses to these comments in the discussion below on the compliance impacts of the rule and elsewhere in the preamble. DOE modified the standards adopted in today's final rule in response to comments received, including those from small businesses, as described in the preamble.

3. Description and Estimated Number of Small Entities Regulated

a. Methodology for Estimating the Number of Small Entities

For manufacturers of distribution transformers, the Small Business Administration (SBA) has set a size threshold, which defines those entities classified as ''small businesses'' for the purposes of the statute. DOE used the SBA's small business size standards to determine whether any small entities would be subject to the requirements of the rule. 65 FR 30836, 30848 (May 15, 2000), as amended at 65 FR 53533, 53544 (Sept. 5, 2000) and codified at 13 CFR part 121. The size standards are listed by NAICS code and industry description and are available at *http://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf*. Distribution transformer manufacturing is classified under NAICS 335311, ''Power, Distribution and Specialty Transformer Manufacturing.'' The SBA sets a threshold of 750 employees or less for an entity to be considered as a small business for this category.

In the February 2012 NOPR, DOE identified approximately 10 liquid-immersed distribution transformer manufacturers, 14 LVDT manufacturers, and 17 MVDT manufacturers of covered equipment that can be considered small businesses. 77 FR 7282 (February 10, 2012). Of the liquid-immersed distribution transformer small business manufacturers, DOE was able to reach and discuss potential standards with six of the 10 small business manufacturers. Of the LVDT manufacturers, DOE was able to contact and discuss potential standards with seven of the 14 small business manufacturers. Of the MVDT manufacturers, DOE was able to reach and discuss potential standards with five of the 17 small business manufacturers. DOE also obtained information about small business impacts while interviewing large manufacturers.

b. Distribution Transformer Industry Structure

Liquid Immersed.

Six major manufacturers supply more than 80 percent of the market for liquid-immersed transformers. None of the major manufacturers of distribution transformers covered in this rulemaking are considered to be small businesses. The vast majority of shipments are manufactured domestically. Electric utilities compose the customer base and typically buy on first-cost. Many small manufacturers position themselves towards the higher end of the market or in particular product niches, such as network transformers or harmonic mitigating transformers, but, in general, competition is based on price after a given unit's specifications are prescribed by a customer.

Low-Voltage Dry-Type.

Four major manufacturers supply more than 80 percent of the market for low-voltage dry-type transformers. None of the major manufacturers of LVDT distribution transformers covered in this rulemaking are small businesses. The customer base rarely purchases on efficiency and is very first-cost conscious, which, in turn, places a premium on economies of scale in manufacturing. DOE estimates approximately 80 percent of the market is served by imports, mostly from Canada and Mexico. Many of the small businesses that compete in the low-voltage dry-type market produce specialized transformers that are not covered under standards. Roughly 50 percent of the market by revenue is not covered under DOE standards. This market is much more fragmented than the one serving DOE-covered LVDT transformers.

In the DOE-covered LVDT market, low-volume manufacturers typically do not compete directly with large manufacturers using business models similar to those of their bigger rivals because scale disadvantages in purchasing and production are usually too great a barrier in this portion of the market. The exceptions to this rule are those companies that also compete in the medium-voltage market and, to some extent, are able to leverage that experience and production economies. More typically, low-volume manufacturers focus their operations on one or two parts of the value chain—rather than all of it—and focus on market segments outside of the high-volume baseline efficiency market.

In terms of operations, some small firms focus on the engineering and design of transformers and source the production of the cores or even the whole transformer, while other small firms focus on just production and rebrand for companies that offer broader solutions through their own sales and distribution networks.

In terms of market focus, many small firms compete entirely in distribution transformer markets that are not covered by statute. DOE did not attempt to contact companies operating solely in this very fragmented market. Of those that do compete in the DOE-covered market, a few small businesses reported a focus on the high-end of the market, often selling NEMA Premium® (equivalent to EL3, EL3, and EL2 for DL6, DL7 and DL8, respectively) or better transformers as retrofit opportunities. Others focus on particular applications or niches, like data centers, and become well-versed in the unique needs of a particular customer base.

Medium-Voltage Dry-Type.

The medium-voltage dry-type transformer market is relatively consolidated with one large company holding a substantial share of the market. Electric utilities and industrial users make up most of the customer base and typically buy on first-cost or features other than efficiency. DOE estimates that at least 75 percent of production occurs domestically. Several manufacturers also compete in the power transformer market. Like the LVDT industry, most small business manufacturers in the MVDT industry often produce transformers not covered under DOE standards. DOE estimates that 10 percent of the market is not covered under standards.

c. Comparison Between Large and Small Entities

Small distribution transformer manufacturers differ from large manufacturers in several ways that affect the extent to which they would be impacted by the proposed standards. Characteristics of small manufacturers include: lower production volumes, fewer engineering resources, less technical expertise, lack of purchasing power for high performance steels, and less access to capital.

Lower production volumes are the root cause of most small business disadvantages, particularly for a small manufacturer that is vertically integrated. A lower-volume manufacturer's conversion costs would need to be spread over fewer units than a larger competitor. Thus, unless the small business can differentiate its product in some way that earns a price premium, the small business is a ''price taker'' and experiences a reduction in profit per unit relative to the large manufacturer. Therefore, because much of the same equipment would need to be purchased by both large and small manufacturers in order to produce transformers (in-house) at higher TSLs, undifferentiated small manufacturers would face a greater variable cost penalty because they must depreciate the one-time conversion expenditures over fewer units.

Smaller companies are also more likely to have more limited engineering resources and they often operate with lower levels of design and manufacturing sophistication. Smaller companies typically also have less experience and expertise in working with more advanced technologies, such as amorphous core construction in the liquid-immersed market or step-lap mitering in the dry-type markets. Standards that required these technologies could strain the engineering resources of these small manufacturers if they chose to maintain a vertically integrated business model.

Small distribution transformer manufacturers can also be at a disadvantage due to their lack of purchasing power for high performance materials. If more expensive steels are needed to meet standards and steel cost grows as a percentage of the overall product cost, small manufacturers who pay higher per pound prices would be disproportionately impacted.

Last, small manufacturers typically have less access to capital, which may be needed by some to cover the conversion costs associated with new technologies.

4. Description and Estimate of Compliance Requirements

a. Liquid-Immersed

Based on interviews with manufacturers in the liquid-immersed market, DOE does not believe small manufacturers will face significant capital conversion costs at the levels established in today's rulemaking. DOE expects small manufacturers of liquid-immersed distribution transformers to continue to produce silicon steel cores, rather than invest in amorphous technology. While silicon steel designs capable of achieving TSL 1 would get larger, and thus reduce throughput, most manufacturers said the industry in general has substantial excess capacity due to the recent economic downturn. Therefore, DOE believes TSL 1 would not require the typical small manufacturer to invest in additional capital equipment. However, small manufacturers may incur some engineering and product design costs associated with re-optimizing their production processes around new baseline equipment. DOE estimates TSL 1 would require industry product conversion costs of only one-half of one year's annual industry R&D expenses. Because these one-time costs are relatively fixed per manufacturer, they impact smaller manufacturers disproportionately (compared to larger manufacturers). The table below illustrates this effect:

TABLE VI.1—ESTIMATED PRODUCT CONVERSION COSTS AS A PERCENTAGE OF ANNUAL R&D EXPENSE

	Product conversion cost	Product conversion cost as a percentage of annual R&D expense
Typical Large Manufacturer	$1.34 M	20
Typical Small Manufacturer	1.34 M	222

While the costs disproportionately impact small manufactures, the standard levels, as stated above, do not require small manufacturers to invest in entirely different production processes nor do they require steels or core construction techniques with which these manufacturers are not familiar. A range of design options would still be available.

b. Low-Voltage Dry-Type.

Small manufacturers have several options available to them at TSL2 based on individual economic determinations. They may choose to: (1) Source their cores, (2) fabricate cores with butt-lapping technology and higher-grade steel, (3) buy a mitering machine (enabling them to build mitered cores with lower-grade steel than would be otherwise required), or (4) exit a product line.

Compared to higher TSLs, TSL 2 provides many more design paths for small manufacturers to comply. DOE's engineering analysis indicates that the efficiency level represented by TSL 2 for DL7 (the high-volume line) could be met without mitering through the use of butt-lapping higher-grade steels. It is uncertain whether small manufacturers would elect to butt-lap with higher grade steel rather than source their cores or invest in mitering equipment, but each option remains a viable path to compliance. With respect to the other paths to compliance, DOE notes that roughly half of the small business LVDT manufacturers DOE interviewed already have mitering capability. DOE estimates half of all cores in small business DL7 transformers are currently sourced, according to transformer and core manufacturer interviews, as third-party core manufacturers already often have significant variable cost advantages through bulk steel purchasing power and greater production efficiencies due to higher volumes.

Each business' ultimate decision on how it will ultimately comply depends on its production volumes, the relative steel prices it faces, its position in the value chain, and whether it currently has mitering technology in-house, among other factors. Because a small business may ultimately make the business decision to build mitered cores at TSL 2, DOE estimates the cost of such a strategy to conservatively bound the compliance impact. Below DOE compares the relative impact on a small business of the scenario in which a small manufacturer elects to purchase a new mitering machine (rather than continue to butt-lap with higher grade steel or source its core production). Based on interviews with small businesses and core manufacturers, DOE believes this to be a conservative assessment of compliance costs, as many small businesses currently source a large share of their cores. DOE estimates capital conversion costs of $0.75 million and product conversion costs of $0.2 million, based on manufacturer and equipment supplier interviews, would be incurred if small businesses without mitering equipment chose to invest in it. Because of the largely fixed nature of these one-time conversion expenditures that distribution transformer manufacturers would incur as a result of standards, small manufacturers who choose to invest in in-house mitering capability will likely be disproportionately impacted (compared to large manufacturers). Based on information gathered in interviews, DOE estimates that three small manufacturers would invest in mitering equipment as result of this rule. As Table VI.2 indicates, small manufacturers face a greater relative hurdle in complying with standards should they opt to continue to maintain core production in-house.

TABLE VI.2—ESTIMATED CAPITAL AND PRODUCT CONVERSION COSTS AS A PERCENTAGE OF ANNUAL CAPITAL EXPENDITURES AND R&D EXPENSE

	Capital conversion cost as a percentage of annual capital expenditures	Product conversion cost as a percentage of annual R&D expense	Total conversion cost as a percentage of annual EBIT
Large Manufacturer	37	10	15
Small Manufacturer	137	44	70

For more than half of the small businesses DOE interviewed, it is already standard practice to source a large percentage of their DOE-covered cores on an ongoing basis or quickly do so when steel prices merit such a strategy. Furthermore, small businesses are currently more likely to source cores for NEMA Premium® units than standard units. Many small businesses indicated that they expect the continuance of this strategy would be the low-cost option under higher standards. Therefore, the impacts in the table are not representative of the strategy DOE expects to be employed by many small manufacturers, but only those choosing to invest in mitering equipment.

For all of the reasons discussed, DOE believes the capital expenditures it estimated above for small businesses are likely conservative and that small businesses have a variety of technical and strategic paths to continue to compete in the market at TSL 2.

c. Medium-Voltage Dry-Type

Based on its engineering analysis and interviews, DOE expects relatively minor capital expenditures for the industry to meet TSL 2. DOE understands that the market is already standardized on step-lap mitering, so manufacturers will not need to make major investments for more advanced core construction. Furthermore, TSL 2 does not require a change to much thinner steels such as M3 or H0. The industry can use M4 and H1, thicker steels with which it has much more experience and which are easier to employ in the stacked-core production process that dominates the medium-voltage market. However, some investment will be required to maintain capacity as some manufacturers will likely migrate towards more M4 and H1 steel and away from the slightly thicker M5, which is also common. Additionally, design options at TSL 2 typically have larger cores, also slowing throughput. Therefore, some manufacturers may need to invest in additional production equipment. Alternatively, depending on each company's availability capacity, manufacturers could employ additional production shifts, rather than invest in additional capacity.

For the medium-voltage dry-type market, at TSL 2, the level proposed in today's notice, DOE estimates low capital and product conversion costs that are relatively fixed for both small and large manufacturers. Similar to the low-voltage dry-type market, small manufacturers will likely be disproportionately impacted compared to large manufacturers due to the fixed nature of the conversion expenditures. Table VI.3 illustrates the relative impacts on small and large manufacturers.

TABLE VI.3—ESTIMATED CAPITAL AND PRODUCT CONVERSION COSTS AS A PERCENTAGE OF ANNUAL CAPITAL EXPENDITURES AND R&D EXPENSE

	Capital conversion cost as a percentage of annual capital expenditures	Product conversion cost as a percentage of annual R&D expense	Total conversion cost as a percentage of annual EBIT
Large Manufacturer	3	9	8
Small Manufacturer	40	117	98

d. Summary of Compliance Impacts

The compliance impacts on small businesses are discussed above for low-voltage dry-type, medium-voltage dry-type, and liquid-filled distribution transformer manufacturers. Although the conversion costs required can be considered substantial for both large and small companies, the impacts could be relatively greater for a typical small manufacturer because of much lower production volumes and the relatively fixed nature of the R&D and capital investments required.

5. Steps Taken to Minimize Impacts on Small Entities and Reasons Why Other Significant Alternatives to Today's Final Rule Were Rejected

DOE modified the standards established in today's final rule from those proposed in the February 2012 NOPR as discussed previously and based on comments and additional test data received from interested parties.

The previous discussion also analyzes impacts on small businesses that would result from the other TSLs DOE considered. Though TSLs lower than the adopted TSL are expected to reduce the impacts on small entities, DOE is required by EPCA to establish standards that achieve the maximum improvement in energy efficiency that are technically feasible and economically justified, and result in a significant conservation of energy. Thus, DOE rejected the lower TSLs.

In addition to the other TSLs being considered, the TSD includes a regulatory impact analysis (chapter 17) that discusses the following policy alternatives: (1) No standard, (2) consumer rebates, (3) consumer tax credits, (4) manufacturer tax credits, and (5) early replacement. DOE does not intend to consider these alternatives further because they are either not feasible to implement, or not expected to result in energy savings as large as those that would be achieved by the standard levels under consideration. Thus, DOE rejected these alternatives and is adopting the standards set forth in this rulemaking.

6. Duplication, Overlap, and Conflict With Other Rules and Regulations

DOE is not aware of any rules or regulations that duplicate, overlap, or conflict with the rule being finalized today.

7. Significant Alternatives to Today's Rule

The discussion above analyzes impacts on small businesses that would result from the other TSLs DOE considered. Though TSLs lower than the selected TSLs are expected to reduce the impacts on small entities, DOE is required by EPCA to establish standards that achieve the maximum improvement in energy efficiency that are technically feasible and economically justified, and result in a significant conservation of energy. Therefore, DOE rejected the lower TSLs.

In addition to the other TSLs being considered, the TSD includes a regulatory impact analysis (chapter 17) that discusses the following policy alternatives: (1) Consumer rebates, (2) consumer tax credits, and (3) manufacturer tax credits. DOE does not intend to consider these alternatives further because they either are not feasible to implement or are not expected to result in energy savings as large as those that would be achieved by the standard levels under consideration.

8. Significant Issues Raised by Public Comments

DOE's MIA suggests that, while TSL1, TSL1, and TSL 2 present greater difficulties for small businesses than lower levels in the liquid-immersed, LVDT, and MVDT classes, respectively, the impacts at higher TSLs would be greater. DOE expects that small businesses will generally be able to profitably compete at the TSL selected in today's rulemaking. DOE's MIA is based on its interviews of both small and large manufacturers, and consideration of small business impacts explicitly enters into DOE's choice of the TSLs selected in this final rule.

DOE also notes that today's standards can be met with a variety of materials, including multiple core steels and both copper and aluminum windings. Because today's TSLs can be met with a variety of materials, DOE does not expect that material availability issues will be a problem for the industry that results from this rulemaking.

9. Steps DOE Has Taken to Minimize the Economic Impact on Small Manufacturers

In consideration of the benefits and burdens of standards, including the burdens posed to small manufacturers, DOE concluded that TSL1 is the highest level that can be justified for liquid-immersed and medium-voltage dry-type transformers and TSL2 is the highest level that can be justified for low-voltage dry-type transformers. As explained in part 6 of the IRFA, ''Significant Alternatives to the Rule,'' DOE explicitly considered the impacts on small manufacturers of liquid-immersed and dry-type transformers in selecting the TSLs in today's rulemaking, rather than selecting a higher trial standard level. It is DOE's belief that levels at TSL3 or higher would place excessive burdens on small manufacturers of medium-voltage dry-type transformers, as would TSL 2 or higher for liquid-immersed and medium-voltage dry-type transformers. Such burdens would include large product redesign costs and also operational problems associated with the extremely thin laminations of core steel that would be needed to meet these levels and advanced core construction equipment and tooling for mitering, or wound-core designs. Similarly, for medium-voltage dry-type, the steels and construction techniques likely to be used at TSL 2 are already commonplace in the market, whereas TSL 3 would likely trigger a more dramatic shift to thinner and more exotic steels, to which many small businesses have limited access. Lastly, DOE is confident that TSL1 for the liquid-immersed distribution transformer market would not require small manufacturers to invest in amorphous steel technology, which could put them at a significant disadvantage.

Section VI.B discusses how small business impacts entered into DOE's selection of today's standards for distribution transformers. DOE made its decision regarding standards by beginning with the highest level considered and successively eliminating TSLs until it found a TSL that is both technologically feasible and economically justified, taking into account other EPCA criteria. Because DOE believes that the TSLs selected are economically justified (including consideration of small business impacts), the reduced impact on small businesses that would have been realized in moving to lower efficiency levels was not considered in DOE's decision (but the reduced impact on small businesses that is realized in moving down to TSL2 from TSL3 (in the case of medium-voltage dry-type and low-voltage dry-type) and to TSL1 from TSL2 (in the case of liquid-immersed) was explicitly considered in the weighing of benefits and burdens).

C. Review Under the Paperwork Reduction Act

Manufacturers of distribution transformers must certify to DOE that their equipment complies with any applicable energy conservation standards. In certifying compliance, manufacturers must test their equipment according to the DOE test procedures for distribution transformers, including any amendments adopted for those test procedures. DOE has established regulations for the certification and recordkeeping requirements for all covered consumer products and commercial equipment, including distribution transformers. (76 FR 12422 (March 7, 2011). The collection-of-information requirement for the certification and recordkeeping is subject to review and approval by OMB under the Paperwork Reduction Act (PRA). This requirement has been approved by OMB under OMB control number 1910–1400. Public reporting burden for the certification is estimated to average 20 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA, unless that collection of information displays a currently valid OMB Control Number.

D. Review Under the National Environmental Policy Act of 1969

Pursuant to the National Environmental Policy Act (NEPA) of 1969, DOE has determined that the rule fits within the category of actions included in Categorical Exclusion (CX) B5.1 and otherwise meets the requirements for application of a CX. See 10 CFR part 1021, App. B, B5.1(b); 1021.410(b) and Appendix B, B(1)–(5). The rule fits within the category of actions because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, and for which none of the exceptions identified in CX B5.1(b) apply. Therefore, DOE has made a CX determination for this rulemaking, and DOE does not need to prepare an Environmental Assessment or Environmental Impact Statement for this rule. DOE's CX determination for this rule is available at *http://cxnepa.energy.gov/* or link directly to *http://energy.gov/nepa/downloads/cx-007852-categorical-exclusion-determination*.

E. Review Under Executive Order 13132

Executive Order 13132, ''Federalism.'' 64 FR 43255 (Aug. 10, 1999) imposes certain requirements on Federal agencies formulating and implementing policies or regulations that preempt State law or that have Federalism implications. The Executive Order requires agencies to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and to carefully assess the necessity for such actions. The Executive Order also requires agencies to have an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications. On March 14, 2000, DOE published a statement of policy describing the intergovernmental consultation process it will follow in the development of such regulations. 65 FR 13735. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the products that are the subject of today's final rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6297) No further action is required by Executive Order 13132.

F. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of Executive Order 12988, ''Civil Justice Reform,'' imposes on Federal agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction. 61 FR 4729 (Feb. 7, 1996). Section 3(b) of Executive Order 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, this final rule meets the relevant standards of Executive Order 12988.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. Pub. L. 104–4, sec. 201 (codified at 2 U.S.C. 1531). For an amended regulatory action likely to result in a rule that may cause the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in any one year (adjusted annually for inflation), section 202 of UMRA requires a Federal agency to publish a written statement that estimates the resulting costs, benefits, and other effects on the national economy. (2 U.S.C. 1532(a), (b)) The UMRA also requires a Federal agency to develop an effective process to permit timely input by elected officers of State, local, and Tribal governments on a ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect small governments. On March 18, 1997, DOE published a statement of policy on its process for intergovernmental consultation under UMRA. 62 FR 12820. DOE's policy statement is also available at *http://energy.gov/gc/office-general-counsel*.

DOE has concluded that this final rule would likely require expenditures of $100 million or more by the private sector. Such expenditures may include: (1) investment in research and development and in capital expenditures by distribution transformer manufacturers in the years between the final rule and the compliance date for the new standards, and (2) incremental additional expenditures by consumers to purchase higher-efficiency distribution transformers, starting at the compliance date for the applicable standard.

Section 202 of UMRA authorizes a Federal agency to respond to the content requirements of UMRA in any other statement or analysis that accompanies the final rule. 2 U.S.C. 1532(c). The content requirements of section 202(b) of UMRA relevant to a private sector mandate substantially overlap the economic analysis requirements that apply under section 325(o) of EPCA and Executive Order 12866. The **SUPPLEMENTARY INFORMATION** section of the final rule and the ''Regulatory Impact Analysis'' section of the TSD for this final rule respond to those requirements.

Under section 205 of UMRA, the Department is obligated to identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a written statement under section 202 is required. 2 U.S.C. 1535(a). DOE is required to select from those alternatives the most cost-effective and least burdensome alternative that achieves the objectives of the rule unless DOE publishes an explanation for doing otherwise, or the selection of such an alternative is inconsistent with law. As required by 42 U.S.C. 6295 (o), 6316(a), and 6317(a)(1), today's final rule would establish energy conservation standards for distribution transformers that are designed to achieve the maximum improvement in energy efficiency that DOE has determined to be both technologically feasible and economically justified. A full discussion of the alternatives considered by DOE is presented in the ''Regulatory Impact Analysis'' chapter of the TSD for today's final rule.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

DOE has determined, under Executive Order 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights'' 53 FR 8859 (March 18, 1988), that this regulation would not result in any takings that might require compensation under the Fifth Amendment to the U.S. Constitution.

J. Review Under the Treasury and General Government Appropriations Act, 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516, note) provides for Federal agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (February 22, 2002), and DOE's guidelines were published at 67 FR 62446 (October 7, 2002). DOE has reviewed today's final rule under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13211

Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' 66 FR 28355 (May 22, 2001), requires Federal agencies to prepare and submit to OIRA at OMB, a Statement of Energy Effects for any significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgates or is expected to lead to promulgation of a final rule, and that: (1) Is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use.

DOE has concluded that today's regulatory action, which sets forth energy conservation standards for distribution transformers, is not a significant energy action because the amended standards are not likely to have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated as such by the Administrator at OIRA. Accordingly, DOE has not prepared a Statement of Energy Effects for the final rule.

L. Review Under the Information Quality Bulletin for Peer Review

On December 16, 2004, OMB, in consultation with the Office of Science and Technology Policy (OSTP), issued its Final Information Quality Bulletin for Peer Review (the Bulletin). 70 FR 2664 (January 14, 2005). The Bulletin establishes that certain scientific information shall be peer reviewed by qualified specialists before it is disseminated by the Federal Government, including influential scientific information related to agency regulatory actions. The purpose of the bulletin is to enhance the quality and credibility of the Government's scientific information. Under the Bulletin, the energy conservation standards rulemaking analyses are ''influential scientific information,'' which the Bulletin defines as scientific information the agency reasonably can determine will have, or does have, a clear and substantial impact on important public policies or private sector decisions. 70 FR 2667.

In response to OMB's Bulletin, DOE conducted formal in-progress peer reviews of the energy conservation standards development process and analyses and has prepared a Peer Review Report pertaining to the energy conservation standards rulemaking analyses. Generation of this report involved a rigorous, formal, and documented evaluation using objective criteria and qualified and independent reviewers to make a judgment as to the technical/scientific/business merit, the actual or anticipated results, and the productivity and management effectiveness of programs and/or projects. The ''Energy Conservation Standards Rulemaking Peer Review Report'' dated February 2007 has been disseminated and is available at the following Web site: *www1.eere.energy.gov/buildings/appliance_standards/peer_review.html.*

M. Congressional Notification

As required by 5 U.S.C. 801, DOE will report to Congress on the promulgation of this rule prior to its effective date. The report will state that it has been determined that the rule is a ''major rule'' as defined by 5 U.S.C. 804(2).

VII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of today's final rule.

List of Subjects in 10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation, Reporting and recordkeeping requirements.

Issued in Washington, DC, on April 9, 2013.

David Danielson,

Assistant Secretary of Energy, Energy Efficiency and Renewable Energy.

For the reasons set forth in the preamble, DOE amends part 431 of chapter II, of title 10 of the Code of Federal Regulations, to read as set forth below:

PART 431—ENERGY EFFICIENCY PROGRAM FOR CERTAIN COMMERCIAL AND INDUSTRIAL EQUIPMENT

■ 1. The authority citation for part 431 continues to read as follows:

Authority: 42 U.S.C. 6291–6317.

■ 2. Section 431.192 is amended by:

■ a. Removing the definition of ''underground mining distribution transformer'' and

■ b. Adding in alphabetical order, the definition for ''mining distribution transformer'' to read as follows:

§ 431.192 Definitions.

* * * * *

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

* * * * *

■ 3. Section 431.196 is revised to read as follows:

§ 431.196 Energy conservation standards and their effective dates.

(a) *Low-Voltage Dry-Type Distribution Transformers.* (1) The efficiency of a low-voltage, dry-type distribution transformer manufactured on or after January 1, 2007, but before January 1, 2016, shall be no less than that required for the applicable kVA rating in the table below. Low-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	%	kVA	%
15	97.7	15	97.0

Single-phase		Three-phase	
kVA	%	kVA	%
25	98.0	30	97.5
37.5	98.2	45	97.7
50	98.3	75	98.0
75	98.5	112.5	98.2
100	98.6	150	98.3
167	98.7	225	98.5
250	98.8	300	98.6
333	98.9	500	98.7
		750	98.8
		1000	98.9

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

(2) The efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA rating in the table below. Low-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

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

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

(b) *Liquid-Immersed Distribution Transformers.* (1) The efficiency of a liquid-immersed distribution transformer manufactured on or after January 1, 2010, but before January 1, 2016, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.62	15	98.36
15	98.76	30	98.62
25	98.91	45	98.76
37.5	99.01	75	98.91
50	99.08	112.5	99.01
75	99.17	150	99.08
100	99.23	225	99.17
167	99.25	300	99.23
250	99.32	500	99.25
333	99.36	750	99.32
500	99.42	1000	99.36
667	99.46	1500	99.42
833	99.49	2000	99.46
		2500	99.49

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

(2) The efficiency of a liquid-immersed distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

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

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

(c) *Medium-Voltage Dry-Type Distribution Transformers.* (1) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after January 1, 2010, but before January 1, 2016, shall be no less than that required for their kVA and BIL rating in the table below. Medium-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase				Three-phase			
kVA	BIL*			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.10	97.86		15	97.50	97.18	
25	98.33	98.12		30	97.90	97.63	
37.5	98.49	98.30		45	98.10	97.86	
50	98.60	98.42		75	98.33	98.12	
75	98.73	98.57	98.53	112.5	98.49	98.30	
100	98.82	98.67	98.63	150	98.60	98.42	
167	98.96	98.83	98.80	225	98.73	98.57	98.53
250	99.07	98.95	98.91	300	98.82	98.67	98.63
333	99.14	99.03	98.99	500	98.96	98.83	98.80
500	99.22	99.12	99.09	750	99.07	98.95	98.91
667	99.27	99.18	99.15	1000	99.14	99.03	98.99
833	99.31	99.23	99.20	1500	99.22	99.12	99.09
				2000	99.27	99.18	99.15
				2500	99.31	99.23	99.20

* BIL means basic impulse insulation level.

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

(2) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA and BIL rating in the table below. Medium-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

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

* BIL means basic impulse insulation level.

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

(d) *Mining Distribution Transformers.* [Reserved]

Appendix

Note: The following letter from the Department of Justice will not appear in the Code of Federal Regulations.

U.S. Department of Justice
Antitrust Division
Joseph F. Wayland
Acting Assistant Attorney General
RFK Main Justice Building
950 Pennsylvania Ave., NW
Washington, D.C. 20530–0001
(202)514–2401/(202)616–2645 (Fax)

September 24, 2012

Eric J. Fygi
Deputy General Counsel
Department of Energy
Washington, DC 20585

Dear Deputy General Counsel Fygi:

I am responding to your August 16, 2012 letter seeking the views of the Attorney General about the potential impact on competition of proposed energy conservation standards for certain types of distribution transformers, namely medium-voltage, dry-type and liquid-immersed distribution transformers, as well as low-voltage, dry-type distribution transformers. Your request was submitted under Section 325(o)(2)(B)(i)(V) of the Energy Policy and Conservation Act, as amended (ECPA), 42 U.S.C. 6295(o)(2)(B)(i)(V), which requires the Attorney General to make a determination of the impact of any lessening of competition that is likely to result from the imposition of proposed energy conservation standards. The Attorney General's responsibility for responding to requests from other departments about the effect of a program on competition has been delegated to the Assistant Attorney General for the Antitrust Division in 28 CFR § 0.40(g).

In conducting its analysis the Antitrust Division examines whether a proposed standard may lessen competition, for example, by substantially limiting consumer choice, by placing certain manufacturers at an unjustified competitive disadvantage, or by inducing avoidable inefficiencies in production or distribution of particular products. A lessening of competition could result in higher prices to manufacturers and consumers, and perhaps thwart the intent of the revised standards by inducing substitution to less efficient products.

We have reviewed the proposed standards contained in the Notice of Proposed Rulemaking (77 Fed. Reg. 7282, February 10, 2012) (NOPR). We have also reviewed supplementary information submitted to the Attorney General by the Department of Energy. The NOPR proposed Trial Standard Level 2 for medium-voltage, dry-type distribution transformers, which was arrived at through a consensus agreement among a diverse array of stakeholders as part of a negotiated rulemaking, and Trial Standard Level 1 for medium-voltage, liquid-immersed and low-voltage, dry-type distribution transformers, after no consensus was reached as part of a negotiated rulemaking. Our review has focused on the standards DOE has proposed adopting. We have not determined the impact on competition of more stringent standards than those proposed in the NOPR.

Based on this review, our conclusion is that the proposed energy conservation standards for medium-voltage, dry-type and liquid-immersed distribution transformers, as well as low-voltage, dry-type distribution transformers, are unlikely to have a significant adverse impact on competition. In reaching our conclusion, we note that the proposed energy standards for medium-voltage, dry-type distribution transformers were arrived at through a consensus agreement among a diverse array of stakeholders.

Sincerely,

Joseph F. Wayland

[FR Doc. 2013–08712 Filed 4–17–13; 8:45 am]

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