DEPARTMENT OF ENERGY

10 CFR Part 431

[EERE–2019–BT–STD–0018]

RIN 1904–AE12

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, as amended (EPCA), 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 periodically review its existing standards to determine whether more stringent standards would be technologically feasible and economically justified, and would result in significant energy savings. In this final rule, DOE is adopting amended energy conservation standards for distribution transformers. It has determined that the amended energy conservation standards for these products would result in significant conservation of energy, and are technologically feasible and economically justified.

DATES: The effective date of this rule is July 8, 2024. Compliance with the amended standards established for distribution transformers in this final rule is required on and after April 23, 2029.

ADDRESSES: The docket for this rulemaking, which includes **Federal Register** notices, public meeting attendee lists and transcripts, comments, and other supporting documents/materials, is available for review at *www.regulations.gov.* 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.

The docket web page can be found at *www.regulations.gov/docket/EERE-2019-BT-STD-0018.* The docket web page contains instructions on how to access all documents, including public comments, in the docket.

For further information on how to review the docket, contact the Appliance and Equipment Standards Program staff at (202) 287–1445 or by email: *ApplianceStandardsQuestions@ee.doe.gov.*

FOR FURTHER INFORMATION CONTACT:

Mr. Jeremy Dommu, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Office, EE–5B, 1000 Independence Avenue SW, Washington, DC 20585–0121. Email: *ApplianceStandardsQuestions@ee.doe.gov.*

Mr. Matthew Schneider, U.S. Department of Energy, Office of the General Counsel, GC–33, 1000 Independence Avenue SW, Washington, DC 20585–0121. Telephone: (202) 597–6265. Email: *matthew.schneider@hq.doe.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Synopsis of the Final Rule

The Energy Policy and Conservation Act, Public Law 94–163, as amended (EPCA),[1] authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. (42 U.S.C. 6291–6317, as codified) Title III, Part B of EPCA [2] established the Energy Conservation Program for Consumer Products Other Than Automobiles. (42 U.S.C. 6291–6309) Title III, Part C of the EPCA, as amended,[3] established the Energy Conservation Program for Certain Industrial Equipment. (42 U.S.C. 6311–6317) The Energy Policy Act of 1992, Public Law 102–486, amended EPCA and directed DOE to prescribe energy conservation standards for those distribution transformers for which DOE determined 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, Public Law. 109–58, amended EPCA to establish energy conservation standards for low-voltage dry-type (LVDT) distribution transformers. (42 U.S.C. 6295(y))

Pursuant to EPCA, DOE is required to review its existing energy conservation standards for covered equipment no later than six years after issuance of any final rule establishing or amending a standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(m)(1)) Pursuant to that statutory provision, DOE must publish either a notification of determination that standards for the product do not need to be amended, or a notice of proposed rulemaking (NOPR) including new proposed energy conservation standards (proceeding to a final rule, as appropriate). (*Id.*) Any new or amended energy conservation standard must be designed to achieve the maximum improvement in energy efficiency that DOE determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A)) Furthermore, the new or amended standard must result in significant conservation of energy. (42 U.S.C. 6295(o)(3)(B)) DOE has conducted this review of the energy conservation standards for distribution transformers under EPCA's six-year-lookback authority. (*Id.*)

In accordance with these and other statutory provisions discussed in this document, DOE analyzed the benefits and burdens of five trial standard levels (TSLs) for liquid-immersed distribution transformers, low-voltage dry-type and medium-voltage dry-type distribution transformers. The TSLs and their associated benefits and burdens are discussed in detail in sections V.A through V.C of this document. As discussed in section V.C of this document, DOE has determined that TSL 3 for liquid-immersed distribution transformers, which corresponds to a 5 percent reduction in losses for single-phase transformers less than or equal to 100 kVA and three-phase transformers greater than or equal to 500 kVA and a 20 percent reduction in losses for single-phase transformers greater than 100 kVA and three-phase transformers less than 500 kVA, represents the maximum improvement in energy efficiency that is technologically feasible and economically justified. For low-voltage dry-type distribution transformers, DOE

[1] All references to EPCA in this document refer to the statute as amended through the Energy Act of 2020, Public Law 116–260 (Dec. 27, 2020), which reflect the last statutory amendments that impact Parts A and A–1 of EPCA.

[2] For editorial reasons, upon codification in the U.S. Code, Part B was redesignated Part A.

[3] For editorial reasons, upon codification in the U.S. Code, Part C was redesignated Part A–1. While EPCA includes provisions regarding distribution transformers in both Part A and Part A–1, for administrative convenience DOE has established the test procedures and standards for distribution transformers in 10 CFR part 431, Energy Efficiency Program for Certain Commercial and Industrial Equipment. DOE refers to distribution transformers generally as ''covered equipment'' in this document.

has determined that TSL 3, corresponding to a 30 percent reduction in losses for single-phase low-voltage dry-type distribution transformers, 20 percent reduction in losses for three-phase low-voltage dry-type distribution transformers represents the maximum improvement in energy efficiency that is technologically feasible and economically justified. For medium-voltage dry-type distribution transformers, DOE has determined that TSL 2 for medium-voltage dry-type (MVDT), corresponding to a 20 percent reduction in losses, represents the maximum improvement in energy efficiency that is technologically feasible and economically justified. The adopted standards, which are expressed in efficiency as a percentage, are shown in Table I.1 through Table I.3. These standards apply to all equipment listed in Table I.1 through Table I.3 and manufactured in, or imported into, the United States starting on April 23, 2029.

BILLING CODE 6450–01–P

Table I.1 Adopted Energy Conservation Standards for Low-Voltage Dry-Type Distribution Transformers

Single-Phase		Three-Phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
15	98.39%	15	98.31%
25	98.60%	30	98.58%
37.5	98.74%	45	98.72%
50	98.81%	75	98.88%
75	98.95%	112.5	98.99%
100	99.02%	150	99.06%
167	99.09%	225	99.15%
250	99.16%	300	99.22%
333	99.23%	500	99.31%
		750	99.38%
		1000	99.42%

Table I.2 Adopted Energy Conservation Standards for Liquid-Immersed Distribution Transformers

Single-Phase		Three-Phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.77%	15	98.92%
15	98.88%	30	99.06%
25	99.00%	45	99.14%
37.5	99.10%	75	99.22%
50	99.15%	112.5	99.29%
75	99.23%	150	99.33%
100	99.29%	225	99.38%
167	99.46%	300	99.42%
250	99.51%	500	99.38%
333	99.54%	750	99.43%
500	99.59%	1000	99.46%
667	99.62%	1500	99.51%
833	99.64%	2000	99.53%
		2500	99.55%
		3750	99.54%
		5000	99.53%

Table I.3 Adopted Energy Conservation Standards for Medium-Voltage Dry-Type Distribution Transformers

Single-Phase				Three-Phase			
	BIL*				BIL		
	20-45 kV	46-95 kV	≥96 kV		20-45 kV	46-95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.29%	98.07%		15	97.75%	97.46%	
25	98.50%	98.31%		30	98.11%	97.87%	
37.5	98.64%	98.47%		45	98.29%	98.07%	
50	98.74%	98.58%		75	98.50%	98.32%	
75	98.86%	98.71%	98.68%	112.5	98.67%	98.52%	
100	98.94%	98.80%	98.77%	150	98.79%	98.66%	
167	99.06%	98.95%	98.92%	225	98.94%	98.82%	98.71%
250	99.16%	99.06%	99.02%	300	99.04%	98.93%	98.82%
333	99.23%	99.13%	99.09%	500	99.18%	99.09%	99.00%
500	99.30%	99.21%	99.18%	750	99.29%	99.21%	99.12%
667	99.34%	99.26%	99.24%	1000	99.35%	99.28%	99.20%
833	99.38%	99.31%	99.28%	1500	99.43%	99.37%	99.29%
				2000	99.49%	99.42%	99.35%
				2500	99.52%	99.47%	99.40%
				3750	99.50%	99.44%	99.40%
				5000	99.48%	99.43%	99.39%

*BIL means basic impulse insulation level.

Table I.4 Impacts of Adopted Energy Conservation Standards on Consumers of Distribution Transformers*

Equipment Class**	Average LCC Savings *(2022$)*	Simple PBP *years*
1A	657	10.7
1B	48	19.5
2A	851	9.2
2B	498	14.6
12	N/A	N/A
3	321	7.4
4	765	3.6
6	1,389	3.3
8	3,794	1.6
10	-1,438	20.1

*No-new standards are currently being proposed for equipment class 12, "N/A" indicates that there are no consumer savings.

** Equipment Classes shown here correspond to the following: 1A - Liquid-Immersed, Medium-Voltage, Single-Phase, >100 kVa and ≤833 kVA; 1B - Liquid-Immersed, Medium-Voltage, Single-Phase, ≥10 kVa and ≤100 kVA; 2A - Liquid-Immersed, Medium-Voltage, Three-Phase, ≥15 kVa and <500 kVA; 2B - Liquid-Immersed, Medium-Voltage, Three-Phase, ≥500 kVa and ≤5000 kVA; 12 – Submersible; 3 - Dry-Type, Low-Voltage, Single-Phase, 15-333 kVA, 4- Dry-Type, Low-Voltage, Three-Phase 15-1000 kVA; 6 – Dry-Type, Medium-Voltage, Three-Phase, 20-45 kV BIL, 15-5000 kVA; 8 – Dry-Type, Medium-Voltage, Three-Phase, 46-95 kV BIL, 15-5000 kVA; 10 – Dry-Type, Medium-Voltage, Three-Phase, ≥95 kV BIL, 255-5000 kVA.

BILLING CODE 6450–01–C

A. Benefits and Costs to Consumers

Table I.4 summarizes DOE's evaluation of the economic impacts of the adopted standards on consumers of distribution transformers, as measured by the average life-cycle cost (LCC) savings and the simple payback period (PBP).[4] The average LCC savings are positive for all equipment classes in all cases, with the exception of equipment class 10 (e,g., medium-voltage, dry-type, three-phase with a BIL of greater than 96 kV and kVA range of 225–5000), and the PBP is less than the average lifetime of distribution transformers, which is estimated to be 32 years (see section IV.F.8 of this document). In the context of this final rule, the term ≥consumer≥ refers to different populations that purchase and bear the operating costs of distribution transformers. Consumers vary by transformer category: for medium-voltage liquid-immersed distribution transformers, the term ≥consumer≥ refers to electric utilities; for low- and medium-voltage dry-type distribution transformers, the term ≥consumer≥ refers to COMMERCIAL AND INDUSTRIAL entities.

DOE's analysis of the impacts of the adopted standards on consumers is described in section IV.F of this document.

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 (2024–2058). Using a real discount rate of 7.4 percent for liquid-immersed distribution transformers, 11.1 percent for LVDT distribution transformers, and 9.0 percent for MVDT distribution transformers, DOE estimates that the INPV for manufacturers of distribution transformers in the case without amended standards is $1,792 million in 2022 dollars for liquid-immersed distribution transformers, $212 million in 2022 dollars for LVDT distribution transformers, and $95 million in 2022 dollars for MVDT distribution transformers. Under the adopted standards, the change in INPV is estimated to range from −8.1 percent to −6.2 percent for liquid-immersed distribution transformers which represents a change in INPV of approximately −$145 million to −$111 million; from −12.8 percent to −8.9 percent for LVDT distribution transformers, which represents a change in INPV of approximately −$27.1 million to −$18.9 million; and −4.7 percent to −2.5 percent for MVDT distribution transformers, which represents a change in INPV of approximately −$4.4 million to −$2.3 million. In order to bring products into compliance with amended standards, it is estimated that the industry would incur total conversion costs of $187 million for liquid-immersed distribution transformer, $36.1 million for LVDT distribution transformers, and $5.7 million for MVDT distribution transformers.

DOE's analysis of the impacts of the adopted standards on manufacturers is described in sections IV.J and V.B.2 of this document.

C. National Benefits and Costs [5]

1. Liquid-Immersed Distribution Transformers

DOE's analyses indicate that the adopted energy conservation standards for distribution transformers would save a significant amount of energy. Relative to the case without amended standards, the lifetime energy savings for liquid-immersed distribution transformers purchased in the 30-year period that begins in the anticipated year of compliance with the amended standards (2029–2058) amount to 2.73 quadrillion British thermal units (Btu), or quads.[6] This represents a savings of 13 percent relative to the energy use of these products in the case without amended standards (referred to as the ''no-new-standards case'').

The cumulative net present value (NPV) of total consumer benefits of the standards for liquid-immersed distribution transformers ranges from $0.56 billion (at a 7-percent discount rate) to $3.41 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product and installation costs for distribution transformers purchased in 2029–2058.

In addition, the adopted standards for liquid-immersed distribution transformers are projected to yield significant environmental benefits. DOE estimates that the standards will result in cumulative emission reductions (over the same period as for energy savings) of 51.40 million metric tons (Mt) [7] of carbon dioxide (CO_2), 12.29 thousand tons of sulfur dioxide (SO_2), 89.85 thousand tons of nitrogen oxides (NO_X), 416.15 thousand tons of methane (CH_4), 0.40 thousand tons of nitrous oxide (N_2O), and 0.08 tons of mercury (Hg).[8]

DOE estimates the value of climate benefits from a reduction in greenhouse gases (GHG) using four different estimates of the social cost of CO_2 (SC–CO_2), the social cost of methane (SC–CH_4), and the social cost of nitrous oxide (SC–N_2O).[9] Together these represent the social cost of GHG (SC–GHG). DOE used interim SC–GHG values (in terms of benefit-per-ton of GHG avoided) developed by an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG).[10] The derivation of these values is discussed in section IV.L of this document. For presentational purposes, the climate benefits associated with the average SC–GHG at a 3-percent discount rate are estimated to be $1.85 billion. DOE does not have a single central SC–GHG point estimate and it emphasizes the importance and value of considering the benefits calculated using all four sets of SC–GHG estimates.

[4] The average LCC savings refer to consumers that are affected by a standard and are measured relative to the efficiency distribution in the no-new-standards case, which depicts the market in the compliance year in the absence of new or amended standards (see section IV.F.10 of this document). The simple PBP, which is designed to compare specific efficiency levels, is measured relative to the baseline product (see section IV.C of this document).

[5] All monetary values in this document are expressed in 2022 dollars and, where appropriate, are discounted to 2024 from the year of compliance (2029) unless explicitly stated otherwise.

[6] The quantity refers to full-fuel-cycle (FFC) energy savings. FFC energy savings includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels) and, thus, presents a more complete picture of the impacts of energy efficiency standards. For more information on the FFC metric, see section IV.H of this document.

[7] A metric ton is equivalent to 1.1 short tons. Results for emissions other than CO_2 are presented in short tons.

[8] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *Annual Energy Outlook 2023* (*AEO2023*). *AEO2023* reflects, to the extent possible, laws and regulations adopted through mid-November 2022, including the Inflation Reduction Act. *See* section IV.K of this document for further discussion of *AEO2023* assumptions that affect air pollutant emissions.

[9] Estimated climate-related benefits are provided in compliance with Executive Order 12866.

[10] To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the February 2021 SC–GHG TSD. *www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

DOE estimated the monetary health benefits of SO_2 and NO_X emissions reductions, using benefit-per-ton estimates from the Environmental Protection Agency,[11] as discussed in section IV.L of this document. DOE estimated the present value of the health benefits would be $1.11 billion using a 7-percent discount rate, and $3.71 billion using a 3-percent discount rate.[12] DOE is currently only monetizing health benefits from changes in ambient fine particulate matter ($PM_{2.5}$) concentrations from two precursors (SO_2 and NO_X), and from changes in ambient ozone from one precursor (NO_X), but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions.

Table I.5 summarizes the monetized benefits and costs expected to result from the amended standards for liquid-immersed distribution transformers. There are other important unquantified effects, including certain unquantified climate benefits, unquantified public health benefits from the reduction of toxic air pollutants and other emissions, unquantified energy security benefits, and distributional effects, among others.

BILLING CODE 6450–01–P

[11] U.S. EPA. Estimating the Benefit per Ton of Reducing Directly Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors. Available at *www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-21-sectors.*

[12] DOE estimates the economic value of these emissions reductions resulting from the considered TSLs for the purpose of complying with the requirements of Executive Order 12866.

Table I.5 Summary of Monetized Benefits and Costs of Adopted Energy Conservation Standards for Liquid Immersed Distribution Transformers (for Units Shipped between 2029 – 2058)

	Billion $2022
3% discount rate	
Consumer Operating Cost Savings	6.07
Climate Benefits*	1.85
Health Benefits**	3.71
Total Benefits†	11.63
Consumer Incremental Product Costs‡	2.66
Net Benefits†	8.97
Change in Producer Cash Flow (INPV)‡‡	(0.15) – (0.11)
7% discount rate	
Consumer Operating Cost Savings	1.99
Climate Benefits* (3% discount rate)	1.85
Health Benefits**	1.11
Total Benefits†	4.95
Consumer Incremental Product Costs‡	1.43
Net Benefits†	3.52
Change in Producer Cash Flow (INPV)‡‡	(0.15) – (0.11)

Note: This table presents the costs and benefits associated with product name shipped in 2029−2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the SC-CO_2, SC-CH_4, and SC-N_2O (model average at 2.5-percent, 3-percent, and 5-percent discount rates; 95th percentile at a 3-percent discount rate) (*see* section IV.L of this document). Together these represent the global SC-GHG. For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.

† Total and net benefits include those consumer, climate, and health benefits that can be quantified and monetized. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For liquid-immersed distribution transformers, the change in INPV ranges from -$145 million to -$111 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the net benefit calculation for this final rule, the net benefits would range from $8.83 billion to $8.86 billion at a 3-percent discount rate and would range from $3.38 billion to $3.41 billion at a 7-percent discount rate. Parentheses () indicate negative values.

BILLING CODE 6450–01–C

The benefits and costs of the adopted standards can also be expressed in terms of annualized values. The monetary values for the total annualized net benefits are (1) the reduced consumer operating costs, minus (2) the increase in product purchase prices and installation costs, plus (3) the value of climate and health benefits of emission reductions, all annualized.[13]

The national operating cost savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered equipment and are measured for the lifetime of distribution transformers shipped in 2029–2058. The benefits associated with reduced emissions achieved as a result of the adopted standards are also calculated based on the lifetime of liquid-immersed distribution transformers shipped in 2029–2058. Total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with a 3-percent discount rate.[14] Estimates of total benefits are presented for all four SC–GHG discount rates in section IV.L of this document.

Table I.6 presents the total estimated monetized benefits and costs associated with the adopted standard, expressed in terms of annualized values. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NOx and SO_2 reductions, and the 3-percent discount rate case for GHG social costs, the estimated cost of the adopted standards for liquid-immersed distribution transformers is $151.1 million per year in increased equipment installed costs, while the estimated annual benefits are $210.2 million from reduced equipment operating costs, $106.1 million in GHG reductions, and $117.0 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $282.3 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the adopted standards for liquid-immersed distribution transformers is $152.6 million per year in increased equipment costs, while the estimated annual benefits are $348.3 million in reduced operating costs, $106.1 million from GHG reductions, and $213.2 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $515.1 million per year.

BILLING CODE 6450–01–P

[13] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2024, the year used for discounting the NPV of total consumer costs and savings. For the benefits, DOE calculated a present value associated with each year's shipments in the year in which the shipments occur (*e.g.,* 2020 or 2030), and then discounted the present value from each year to 2024. Using the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in the compliance year, that yields the same present value.

[14] As discussed in section IV.L.1 of this document, DOE agrees with the IWG that using consumption-based discount rates *e.g.,* 3 percent) is appropriate when discounting the value of climate impacts. Combining climate effects discounted at an appropriate consumption-based discount rate with other costs and benefits discounted at a capital-based rate (*i.e.,* 7 percent) is reasonable because of the different nature of the types of benefits being measured.

Table I.6 Annualized Benefits and Costs of Adopted Energy Conservation Standards (TSL 3) for Liquid-immersed Distribution Transformers (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	348.3	329.0	407.3
Climate Benefits*	106.1	103.7	119.9
Health Benefits**	213.2	208.1	241.9
Total Benefits†	667.6	640.8	769.2
Consumer Incremental Equipment Costs‡	152.6	194.5	156.5
Net Benefits†	515.1	446.2	612.7
Change in Producer Cash Flow (INPV)‡‡	(11.7) – (8.9)	(11.7) – (8.9)	(11.7) – (8.9)
7% discount rate			
Consumer Operating Cost Savings	210.2	199.6	242.5
Climate Benefits* (3% discount rate)	106.1	103.7	119.9
Health Benefits**	117.0	114.6	131.0
Total Benefits†	433.4	417.9	493.5
Consumer Incremental Equipment Costs‡	151.1	186.5	155.1
Net Benefits†	282.3	231.4	338.4
Change in Producer Cash Flow (INPV)‡‡	(11.7) – (8.9)	(11.7) – (8.9)	(11.7) – (8.9)

Note: This table presents the costs and benefits associated with equipment shipped in 2029–2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029–2058. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the *AEO2023* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a constant rate in the Primary Estimate, an increase in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in section IV.F.1 of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For liquid-immersed distribution transformers, the annualized change in INPV ranges from -$11.7 million to -$8.9 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $709.5 million to $712.3 million at a 3-percent discount rate and would range from $476.6 million to $479.4 million at a 7-percent discount rate. Parentheses () indicate negative values.

BILLING CODE 6450–01–C

2. Low-Voltage Dry-Type Distribution Transformers

DOE's analyses indicate that the adopted energy conservation standards for distribution transformers would save a significant amount of energy. Relative to the case without amended standards, the lifetime energy savings for low-voltage dry-type distribution transformers purchased in the 30-year period that begins in the anticipated year of compliance with the amended standards (2029–2058) amount to 1.71 quadrillion Btu, or quads.[15] This represents a savings of 35 percent relative to the energy use of these products in the no-new-standards case.

The cumulative NPV of total consumer benefits of the standards for low-voltage dry-type distribution transformers ranges from $2.08 billion (at a 7-percent discount rate) to 6.68 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product and installation costs for distribution transformers purchased in 2029–2058.

In addition, the adopted standards for low-voltage dry-type distribution transformers are projected to yield significant environmental benefits. DOE estimates that the standards will result in cumulative emission reductions (over the same period as for energy savings) of 31.28 million Mt[16] of CO_2, 7.49 thousand tons of SO_2, 55.92 thousand tons of NO_X, 259.96 thousand tons of CH_4, 0.24 thousand tons of N_2O, and 0.05 tons of Hg.[17]

DOE estimates the value of climate benefits from a reduction in GHG using four different estimates of the SC-$_{CO2}CO_2$, the SC–CH_4, and the SC–N_2O. Together these represent the SC–GHG. DOE used interim SC–GHG values (in terms of benefit per ton of GHG avoided) developed by an IWG.[18] The derivation of these values is discussed in section IV.L of this document. For presentational purposes, the climate benefits associated with the average SC–GHG at a 3-percent discount rate are estimated to be $1.23 billion. DOE does not have a single central SC–GHG point estimate and it emphasizes the importance and value of considering the benefits calculated using all four sets of SC–GHG estimates.

DOE estimated the monetary health benefits of SO_2 and NO_X emissions reductions, using benefit per ton estimates from the Environmental Protection Agency,[19] as discussed in section IV.L of this document. DOE did not monetize the reduction in mercury emissions because the quantity is very

[15] The quantity refers to FFC energy savings. FFC energy savings includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels) and, thus, presents a more complete picture of the impacts of energy efficiency standards. For more information on the FFC metric, see section IV.H of this document.

[16] A metric ton is equivalent to 1.1 short tons. Results for emissions other than CO_2 are presented in short tons.

[17] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *AEO2023. AEO2023* reflects, to the extent possible, laws and regulations adopted through mid-November 2022, including the Inflation Reduction Act. *See* section IV.K of this document for further discussion of *AEO2023* assumptions that affect air pollutant emissions.

[18] To monetize the benefits of reducing GHG emissions, this analysis uses values that are based on the February 2021 SC-GHG TSD. *www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument__SocialCostofCarbonMethaneNitrousOxide.pdf.*

[19] U.S. EPA. Estimating the Benefit per Ton of Reducing Directly Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors. Available at *www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-21-sectors.*

small. DOE estimated the present value of the health benefits would be $0.76 billion using a 7-percent discount rate, and $2.42 billion using a 3-percent discount rate.[20] DOE is currently only monetizing health benefits from changes in ambient $PM_{2.5}$ concentrations from two precursors (SO_2 and NO_X), and from changes in ambient ozone from one precursor (for NO_X), but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions.

Table I.7 summarizes the monetized benefits and costs expected to result from the amended standards for low-voltage dry-type distribution transformers. There are other important unquantified effects, including certain unquantified climate benefits, unquantified public health benefits from the reduction of toxic air pollutants and other emissions, unquantified energy security benefits, and distributional effects, among others.

BILLING CODE 6450–01–P

Table I.7 Summary of Monetized Benefits and Costs of Adopted Energy Conservation Standards for Low-Voltage Dry-type Distribution Transformers (for Units Shipped between 2029 – 2058)

	Billion $2022
3% discount rate	
Consumer Operating Cost Savings	7.85
Climate Benefits*	1.23
Health Benefits**	2.42
Total Benefits†	11.50
Consumer Incremental Product Costs‡	1.17
Net Benefits†	10.33
Change in Producer Cash Flow (INPV)‡‡	(0.03) – (0.02)
7% discount rate	
Consumer Operating Cost Savings	2.71
Climate Benefits* (3% discount rate)	1.23
Health Benefits**	0.76
Total Benefits†	4.70
Consumer Incremental Product Costs‡	0.63
Net Benefits†	4.07
Change in Producer Cash Flow (INPV)‡‡	(0.03) – (0.02)

Note: This table presents the costs and benefits associated with equipment shipped in 2029−2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the social cost of carbon ($SC\text{-}CO_2$), methane ($SC\text{-}CH_4$), and nitrous oxide ($SC\text{-}N_2O$) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate) (see section IV.L of this document). Together these represent the global SC-GHG. For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the

[20] DOE estimates the economic value of these emissions reductions resulting from the considered TSLs for the purpose of complying with the requirements of Executive Order 12866.

Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990 published in February 2021 by the IWG.
** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. See section IV.L of this document for more details.
† Total and net benefits include those consumer, climate, and health benefits that can be quantified and monetized. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate.
‡ Costs include incremental equipment costs as well as installation costs.
‡‡ Operating Cost Savings are calculated based on the life cycle costs analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impacts analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customers. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cashflow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. Change in INPV is calculated using the industry weighted average cost of capital value of 11.1 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For LVDT distribution transformers, the change in INPV ranges from -$27.1 million to -$18.9 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the net benefit calculation for this final rule, the net benefits would range from $10.30 billion to $10.31 billion at 3-percent discount rate and would range from $4.04 billion to $4.05 billion at 7-percent discount rate. Parentheses () indicate negative values.

BILLING CODE 6450–01–C

The benefits and costs of the adopted standards can also be expressed in terms of annualized values. The monetary values for the total annualized net benefits are (1) the reduced consumer operating costs, minus (2) the increase in product purchase prices and installation costs, plus (3) the value of climate and health benefits of emission reductions, all annualized.[21]

The national operating cost savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered equipment and are measured for the lifetime of distribution transformers shipped in 2029–2058. The benefits associated with reduced emissions achieved as a result of the adopted standards are also calculated based on the lifetime of low-voltage dry-type distribution transformers shipped in 2029–2058. Total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with a 3-percent discount rate.[22] Estimates of total benefits are presented for all four SC–GHG discount rates in section IV.L of this document.

Table I.8 presents the total estimated monetized benefits and costs associated with the adopted standard, expressed in terms of annualized values. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NOx and SO_2 reductions, and the 3-percent discount rate case for GHG social costs, the estimated cost of the adopted standards for low-voltage dry-type is $66.6 million per year in increased equipment installed costs, while the estimated annual benefits are $286.8 million from reduced equipment operating costs, $70.4 million in GHG reductions, and $80.3 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $370.8 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of

[21] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2024, the year used for discounting the NPV of total consumer costs and savings. For the benefits, DOE calculated a present value associated with each year's shipments in the year in which the shipments occur (*e.g.,* 2020 or 2030), and then discounted the present value from each year to 2024. Using the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in the compliance year, that yields the same present value.

[22] As discussed in section IV.L.1 of this document, DOE agrees with the IWG that using consumption-based discount rates *e.g.,* 3 percent) is appropriate when discounting the value of climate impacts. Combining climate effects discounted at an appropriate consumption-based discount rate with other costs and benefits discounted at a capital-based rate (*i.e.,* 7 percent) is reasonable because of the different nature of the types of benefits being measured.

the adopted standards for low-voltage dry-type is $67.4 million per year in increased equipment costs, while the estimated annual benefits are $450.9 million in reduced operating costs, $70.4 million from GHG reductions, and $139.1 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $593.0 million per year.

BILLING CODE 6450–01–P

Table I.8 Annualized Benefits and Costs of Adopted Energy Conservation Standards (TSL 3) for Low-Voltage Dry-Type Distribution Transformers (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	450.9	434.3	463.1
Climate Benefits*	70.4	70.4	70.4
Health Benefits**	139.1	139.1	139.1
Total Benefits†	660.4	643.8	672.6
Consumer Incremental Equipment Costs‡	67.4	89.4	60.6
Net Benefits†	593.0	554.4	612.0
Change in Producer Cash Flow (INPV)‡‡	(3.1) – (2.2)	(3.1) – (2.2)	(3.1) – (2.2)
7% discount rate			
Consumer Operating Cost Savings	286.8	276.8	294.6
Climate Benefits* (3% discount rate)	70.4	80.3	80.3
Health Benefits**	80.3	70.4	70.4
Total Benefits†	437.4	427.5	445.3
Consumer Incremental Equipment Costs‡	66.6	85.1	60.8
Net Benefits†	370.8	342.4	384.5
Change in Producer Cash Flow (INPV)‡‡	(3.1) – (2.2)	(3.1) – (2.2)	(3.1) – (2.2)

Note: This table presents the costs and benefits associated with equipment shipped in 2029−2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029−2058. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the *AEO2023* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a constant rate in the Primary Estimate, an increasing in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in section IV.F.1 of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.
* Climate benefits are calculated using four different estimates of the global SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.
** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.
† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.
‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life cycle costs analysis and national impact analysis as discussed in detail. *See* sections IV.F and IV.H of this document. DOE's national impacts analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cashflow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 11.1 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For LVDT distribution transformers, the annualized change in INPV ranges from -$3.1 million to -$2.2 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $589.9 million to $590.8 million at 3-percent discount rate and would range from $367.7 million to $368.6 million at 7-percent discount rate. Parentheses () indicate negative values.

BILLING CODE 6450–01–C

3. Medium-Voltage Dry-Type Distribution Transformers

DOE's analyses indicate that the adopted energy conservation standards for medium-voltage dry-type distribution transformers would save a significant amount of energy. Relative to the case without amended standards, the lifetime energy savings for distribution transformers purchased in the 30-year period that begins in the anticipated year of compliance with the amended standards (2029–2058) amount to 0.14 quadrillion Btu, or quads.[23] This represents a savings of 9 percent relative to the energy use of these products in the no-new-standards case.

The cumulative NPV of total consumer benefits of the standards for medium-voltage dry-type distribution transformers ranges from $0.03 (at a 7-percent discount rate) to $0.22 (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product and installation costs for distribution transformers purchased in 2029–2058.

In addition, the adopted standards for medium-voltage dry-type distribution transformers are projected to yield significant environmental benefits. DOE estimates that the standards will result in cumulative emission reductions (over the same period as for energy savings) of 2.59 million Mt [24] of CO_2, 0.63 thousand tons of SO_2, 4.69 thousand tons of NO_X, 21.86 thousand tons of CH_4, 0.02 thousand tons of N_2O, and 0.00 tons of Hg.[25]

DOE estimates the value of climate benefits from a reduction in GHG using four different estimates of the SC–CO_2, the SC–CH_4, and the SC–N_2O. Together these represent the SC–GHG. DOE used interim SC–GHG values (in terms of benefit per ton of GHG avoided) developed by an IWG.[26] The derivation of these values is discussed in section IV.L of this document. For presentational purposes, the climate benefits associated with the average SC–GHG at a 3-percent discount rate are estimated to be $0.10 billion. DOE does not have a single central SC–GHG point estimate and it emphasizes the importance and value of considering the benefits calculated using all four sets of SC–GHG estimates.

DOE estimated the monetary health benefits of SO_2 and NO_X emissions reductions, using benefit per ton estimates from the Environmental Protection Agency,[27] as discussed in section IV.L of this document. DOE did not monetize the reduction in mercury emissions because the quantity is very small. DOE estimated the present value of the health benefits would be $0.06 billion using a 7-percent discount rate, and $0.20 billion using a 3-percent discount rate.[28] DOE is currently only monetizing health benefits from changes in ambient $PM_{2.5}$ concentrations from two precursors (SO_2 and NO_X), and from changes in ambient ozone from one precursor (for NO_X), but will continue to assess the ability to monetize other

[23] The quantity refers to FFC energy savings. FFC energy savings includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels) and, thus, presents a more complete picture of the impacts of energy efficiency standards. For more information on the FFC metric, see section IV.H of this document.

[24] A metric ton is equivalent to 1.1 short tons. Results for emissions other than CO_2 are presented in short tons.

[25] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *AEO2023. AEO2023* reflects, to the extent possible, laws and regulations adopted through mid-November 2022, including the Inflation Reduction Act. *See* section IV.K of this document for further discussion of *AEO2023* assumptions that affect air pollutant emissions.

[26] To monetize the benefits of reducing GHG emissions, this analysis uses values that are based on the February 2021 SC–GHG TSD. *www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

[27] U.S. EPA. Estimating the Benefit per Ton of Reducing Directly Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors. Available at *www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-21-sectors.*

[28] DOE estimates the economic value of these emissions reductions resulting from the considered TSLs for the purpose of complying with the requirements of Executive Order 12866.

effects such as health benefits from reductions in direct $PM_{2.5}$ emissions.

Table I.9 summarizes the monetized benefits and costs expected to result from the amended standards for medium-voltage dry-type distribution transformers. There are other important unquantified effects, including certain unquantified climate benefits, unquantified public health benefits from the reduction of toxic air pollutants and other emissions, unquantified energy security benefits, and distributional effects, among others.

BILLING CODE 6450–01–P

Table I.9 Summary of Monetized Benefits and Costs of Adopted Energy Conservation Standards for Medium-Voltage Dry-Type Distribution Transformers (for Units Shipped between 2029 – 2058)

	Billion $2022
3% discount rate	
Consumer Operating Cost Savings	0.44
Climate Benefits*	0.10
Health Benefits**	0.20
Total Benefits†	0.74
Consumer Incremental Product Costs‡	0.22
Net Benefits†	0.52
Change in Producer Cash Flow (INPV)‡‡	(0.004) – (0.002)
7% discount rate	
Consumer Operating Cost Savings	0.15
Climate Benefits* (3% discount rate)	0.10
Health Benefits**	0.06
Total Benefits†	0.32
Consumer Incremental Product Costs‡	0.12
Net Benefits†	0.20
Change in Producer Cash Flow (INPV)‡‡	(0.004) – (0.002)

Note: This table presents the costs and benefits associated with product name shipped in 2029−2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the SC-CO_2, SC-CH_4, and SC-N_2O (model average at 2.5-percent, 3-percent, and 5-percent discount rates; 95th percentile at a 3-percent discount rate) (*see* section IV.L of this document). Together these represent the global SC-GHG. For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.

† Total and net benefits include those consumer, climate, and health benefits that can be quantified and monetized. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the

increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The change in INPV is calculated using the industry weighted average cost of capital value of 9.0 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For MVDT distribution transformers, the change in INPV ranges from -$4.4 million to -$2.3 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the net benefit calculation for this final rule, the net benefits would range from $0.516 billion to $0.518 billion at a 3-percent discount rate and would range from $0.196 billion to $0.198 billion at a 7-percent discount rate.

BILLING CODE 6450–01–C

The benefits and costs of the adopted standards can also be expressed in terms of annualized values. The monetary values for the total annualized net benefits are (1) the reduced consumer operating costs, minus (2) the increase in product purchase prices and installation costs, plus (3) the value of climate and health benefits of emission reductions, all annualized.[29]

The national operating cost savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered equipment and are measured for the lifetime of medium-voltage dry-type distribution transformers shipped in 2029–2058. The benefits associated with reduced emissions achieved as a result of the adopted standards are also calculated based on the lifetime of distribution transformers shipped in 2029–2058. Total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with a 3-percent discount rate.[30] Estimates of total benefits are presented for all four SC–GHG discount rates in section IV.L of this document.

Table I.10 presents the total estimated monetized benefits and costs associated with the adopted standard, expressed in terms of annualized values. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NO_X and SO_2 reductions, and the 3-percent discount rate case for GHG social costs, the estimated cost of the adopted standards for medium-voltage dry-type is $12.5 million per year in increased equipment installed costs, while the estimated annual benefits are $15.9 million from reduced equipment operating costs, $5.9 million in GHG reductions, and $6.7 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $16.0 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the adopted standards for medium-voltage dry-type distribution transformers is $12.7 million per year in increased equipment costs, while the estimated annual benefits are $25.1 million in reduced operating costs, $5.9 million from GHG reductions, and $11.7 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $29.9 million per year.

BILLING CODE 6450–01–P

[29] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2024, the year used for discounting the NPV of total consumer costs and savings. For the benefits, DOE calculated a present value associated with each year's shipments in the year in which the shipments occur (*e.g.*, 2020 or 2030), and then discounted the present value from each year to 2024. Using the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in the compliance year, that yields the same present value.

[30] As discussed in section IV.L.1 of this document, DOE agrees with the IWG that using consumption-based discount rates *e.g.,* 3 percent) is appropriate when discounting the value of climate impacts. Combining climate effects discounted at an appropriate consumption-based discount rate with other costs and benefits discounted at a capital-based rate (*i.e.,* 7 percent) is reasonable because of the different nature of the types of benefits being measured.

Table I.10 Annualized Benefits and Costs of Adopted Energy Conservation Standards (TSL 2) for Medium-Voltage Dry-Type Distribution Transformers (for Units Shipped between 2029 – 2058)

	Million 2022$/year		
	Primary Estimate	**Low-Net-Benefits Estimate**	**High-Net-Benefits Estimate**
3% discount rate			
Consumer Operating Cost Savings	25.1	24.1	25.8
Climate Benefits*	5.9	5.9	5.9
Health Benefits**	11.7	11.7	11.7
Total Benefits†	42.6	41.6	43.3
Consumer Incremental Product Costs‡	12.7	17.1	11.3
Net Benefits†	29.9	24.5	32.0
Change in Producer Cash Flow (INPV)‡‡	(0.4) – (0.2)	(0.4) – (0.2)	(0.4) – (0.2)
7% discount rate			
Consumer Operating Cost Savings	15.9	15.4	16.4
Climate Benefits* (3% discount rate)	5.9	6.7	6.7
Health Benefits**	6.7	5.9	5.9
Total Benefits†	28.5	28.0	29.0
Consumer Incremental Product Costs‡	12.5	16.3	11.3
Net Benefits†	16.0	11.7	17.6
Change in Producer Cash Flow (INPV)‡‡	(0.4) – (0.2)	(0.4) – (0.2)	(0.4) – (0.2)

Note: This table presents the costs and benefits associated with equipment shipped in 2029−2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029−2058. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the *AEO2023* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a constant rate in the Primary Estimate, an increase in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in section IV.F.1 of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.
† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.
‡ Costs include incremental equipment costs as well as installation costs.
‡‡ Operating Cost Savings are calculated based on the life cycle costs analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impacts analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cashflow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 9.0 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For MVDT distribution transformers, the annualized change in INPV ranges from -$0.4 million to -$0.2 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $29.5 million to $29.7 million at 3-percent discount rate and would range from $15.6 million to $15.8 million at 7-percent discount rate. Parentheses () indicate negative values.

BILLING CODE 6450–01–C

DOE's analysis of the national impacts of the adopted standards is described in sections IV.H, IV.K, and IV.L of this document.

D. Conclusion

DOE concludes that the standards adopted in this final rule represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in the significant conservation of energy. Specifically, with regards to technological feasibility, products are already commercially available which either achieve these standard levels or utilize the technologies required to achieve these standard levels for all product classes covered by this proposal. As for economic justification, DOE's analysis shows that the benefits of the standards exceed, to a great extent, the burdens of the standards.

Table I.11 shows the annualized values for all distribution transformers under amended standards, expressed in 2022$. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NOx and SO_2 reduction benefits, and a 3-percent discount rate case for GHG social costs, the estimated cost of the standards for distribution transformers is $ 230.3 million per year in increased distribution transformers costs, while the estimated annual benefits are $512.9 million in reduced distribution transformers operating costs, $182.4 million in climate benefits, and $204.1 million in health benefits. The net benefit amounts to $669.1 million per year. DOE notes that the net benefits are substantial even in the absence of the climate benefits,[31] and DOE would adopt the same standards in the absence of such benefits.

The significance of energy savings offered by a new or amended energy conservation standard cannot be determined without knowledge of the specific circumstances surrounding a given rulemaking.[32] For example, some covered products and equipment have most of their energy consumption occur during periods of peak energy demand. The impacts of these products on the energy infrastructure can be more pronounced than products with relatively constant demand. Accordingly, DOE evaluates the significance of energy savings on a case-by-case basis.

As previously mentioned, the standards are projected to result in estimated national energy savings of 4.58 quads full fuel cycle (FFC), the equivalent of the primary annual energy use of 49.2 million homes. In addition, they are projected to reduce cumulative CO_2 emissions by 85.27 Mt. Based on these findings, DOE has determined the energy savings from the standard levels

[31] The information on climate benefits is provided in compliance with Executive Order 12866.

[32] Procedures, Interpretations, and Policies for Consideration in New or Revised Energy Conservation Standards and Test Procedures for Consumer Products and Commercial/Industrial Equipment, 86 FR 70892, 70901 (Dec. 13, 2021).

adopted in this final rule are ''significant'' within the meaning of 42 U.S.C. 6295(o)(3)(B). A more detailed discussion of the basis for these conclusions is contained in the remainder of this document and the accompanying TSD.

BILLING CODE 6450–01–P

Table I.11 Annualized Benefits and Costs of Adopted Energy Conservation Standards for all Distribution Transformers at Adopted Standard Levels (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	824.3	787.5	896.2
Climate Benefits*	182.4	179.9	196.2
Health Benefits**	364.0	358.8	392.7
Total Benefits†	1,370.6	1,326.2	1,485.1
Consumer Incremental Product Costs‡	232.6	301.1	228.4
Net Benefits†	1,138.0	1,025.1	1,256.7
Change in Producer Cash Flow (INPV)‡‡	(15.2) – (11.3)	(15.2) – (11.3)	(15.2) – (11.3)
7% discount rate			
Consumer Operating Cost Savings	512.9	491.8	553.5
Climate Benefits* (3% discount rate)	182.4	179.9	196.2
Health Benefits**	204.1	201.6	218.1
Total Benefits†	899.4	873.3	967.7
Consumer Incremental Product Costs‡	230.3	287.8	227.2
Net Benefits†	669.1	585.5	740.6
Change in Producer Cash Flow (INPV)‡‡	(15.2) – (11.3)	(15.2) – (11.3)	(15.2) – (11.3)

Note: This table presents the costs and benefits associated with distribution transformers shipped in 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO_2), methane (SC-CH_4), and nitrous oxide (SC-N_2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate) (see section IV.L of this document). Together these represent the global social cost of greenhouse gases (SC-GHG). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate. See section. IV.L of this document for more details. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22-30087) granted the Federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana v. Biden*, No. 21-cv-1074-JDC-KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the Federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from "adopting, employing, treating as binding, or relying upon" the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. The benefits are based on the low estimates of the monetized value. DOE is currently only monetizing (for SO_x and NO_x) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. See sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). See section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent, 11.1 percent, and 9.0 percent for liquid-immersed, LVDT, and MVDT distribution transformers respectively that is estimated in the manufacturer impact analysis (see chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For distribution transformers, the annualized change in INPV ranges from -$15.2 million to -$11.3 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. See section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $1,187.3 million to $1,191.2 million at a 3-percent discount rate and would range from $694.0 million to $697.9 million at a 7-percent discount rate. Parentheses () indicate negative values.

Table I.12 Summary of Monetized Benefits and Costs of Adopted Energy Conservation Standards for all Distribution Transformers at Adopted Standard Levels (for Units Shipped between 2029 – 2058)

	Billion $2022
3% discount rate	
Consumer Operating Cost Savings	14.36
Climate Benefits*	3.18
Health Benefits**	6.33
Total Benefits†	23.87
Consumer Incremental Product Costs‡	4.05
Net Benefits†	19.82
Change in Producer Cash Flow (INPV)‡‡	(0.18) – (0.13)
7% discount rate	
Consumer Operating Cost Savings	4.85
Climate Benefits* (3% discount rate)	3.18
Health Benefits**	1.93
Total Benefits†	9.96
Consumer Incremental Product Costs‡	2.18
Net Benefits†	7.78
Change in Producer Cash Flow (INPV)‡‡	(0.18) – (0.13)

Note: This table presents the costs and benefits associated with distribution transformers shipped in 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO_2), methane (SC-CH_4), and nitrous oxide (SC-N_2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate) (see section IV.L of this document). Together these represent the global social cost of greenhouse gases (SC-GHG). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate. See section. IV.L of this document for more details. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22-30087) granted the Federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana v. Biden*, No. 21-cv-1074-JDC-KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the Federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from "adopting, employing, treating as binding, or relying upon" the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from

reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. See sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). See section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. Change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent, 11.1 percent, and 9.0 percent for liquid-immersed, LVDT, and MVDT distribution transformers respectively that is estimated in the manufacturer impact analysis (see chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For distribution transformers, the change in INPV ranges from -$176.5 million to -$132.2 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. See section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the net benefit calculation for this final rule, the net benefits would range from $8.39 billion to $8.44 billion at a 3-percent discount rate and would range from $21.47 billion to $21.52 billion at a 7-percent discount rate. Parentheses () indicate negative values.

BILLING CODE 6450–01–C

II. Introduction

The following section briefly discusses the statutory authority underlying this final rule, as well as some of the relevant historical background related to the establishment of standards for distribution transformers.

A. Authority

EPCA authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. (42 U.S.C. 6291–6317, as codified) Title III, Part B of EPCA established the Energy Conservation Program for Consumer Products Other Than Automobiles. (42 U.S.C. 6291–6309) Title III, Part C of EPCA,[33] as amended, established the Energy Conservation Program for Certain Industrial Equipment. (42 U.S.C. 6311–6317) The Energy Policy Act of 1992, Public Law 102–486, amended EPCA and directed DOE 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, Public Law 109–58, also amended EPCA to establish energy conservation standards for low-voltage dry-type distribution transformers. (42 U.S.C. 6295(y))

EPCA further provides that, not later than six years after the issuance of any final rule establishing or amending a standard, DOE must publish either a notice of determination that standards for the product do not need to be amended, or a NOPR including new proposed energy conservation standards (proceeding to a final rule, as appropriate). (42 U.S.C. 6316(a); 42 U.S.C. 6295(m)(1))

The energy conservation program under EPCA consists essentially of four parts: (1) testing, (2) labeling, (3) the establishment of Federal energy conservation standards, and (4) certification and enforcement procedures. Relevant provisions of EPCA include definitions (42 U.S.C. 6311), test procedures (42 U.S.C. 6314), labeling provisions (42 U.S.C. 6315), energy conservation standards (42 U.S.C. 6313), and the authority to require information and reports from manufacturers (42 U.S.C. 6316).

Federal energy efficiency requirements for covered equipment established under EPCA generally supersede State laws and regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6316(a) and 42 U.S.C. 6316(b); 42 U.S.C. 6297) DOE may, however, grant waivers of Federal preemption in limited instances for particular State laws or regulations, in accordance with the procedures and other provisions set

[33] As noted previously, for editorial reasons, upon codification in the U.S. Code, Part C was redesignated Part A–1.

forth under EPCA. ((*See* 42 U.S.C. 6316(a) (applying the preemption waiver provisions of 42 U.S.C. 6297).)

Subject to certain criteria and conditions, DOE is required to develop test procedures to measure the energy efficiency, energy use, or estimated annual operating cost of each covered product. (*See* 42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(A) and (r).) Manufacturers of covered equipment must use the Federal test procedures as the basis for certifying to DOE that their equipment complies with the applicable energy conservation standards and as the basis for any representations regarding the energy use or energy efficiency of the equipment. (42 U.S.C. 6316(a); 42 U.S.C. 6295(s); 42 U.S.C. 6314(d)). Similarly, DOE must use these test procedures to evaluate whether a basic model complies with the applicable energy conservation standard(s). (42 U.S.C. 6316(a); 42 U.S.C. 6295(s)) 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 must follow specific statutory criteria for prescribing new or amended standards for covered equipment, including distribution transformers. Any new or amended standard for a covered product must be designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy (''Secretary'') determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B))

Moreover, DOE may not prescribe a standard (1) for certain products, including distribution transformers, if no test procedure has been established for the product, or (2) if DOE determines by rule that the establishment of such standard will not result in significant conservation of energy (or, for certain products, water), or is not technologically feasible or economically justified. ((42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(A)–(B)) In deciding whether a proposed standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens. *Id.* DOE must make this determination after receiving comments on the proposed standard, and by considering, to the greatest extent practicable, the following seven statutory factors:

(1) The economic impact of the standard on manufacturers and consumers of the products 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 equipment that are likely to result from the standard;

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

(4) Any lessening of the utility or the performance of the covered equipment likely to result from the standard;

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

(6) The need for national energy and water conservation; and

(7) Other factors the Secretary considers relevant.

(42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII))

Further, EPCA, as codified, 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 savings during the first year that the consumer will receive as a result of the standard, as calculated under the applicable test procedure. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(iii))

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. 6316(a); 42 U.S.C. 6295(o)(1)) 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 in 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. 6316(a); 42 U.S.C. 6295(o)(4))

Additionally, EPCA specifies requirements when promulgating an energy conservation standard for a covered product that has two or more subcategories. A rule prescribing an energy conservation standard for a type (or class) of product must specify a different standard level for a type or class of products that has the same function or intended use if DOE determines that products within such group (A) consume a different kind of energy from that consumed by other covered equipment within such type (or class); or (B) have a capacity or other performance-related feature which other products within such type (or class) do not have and such feature justifies a higher or lower standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(1)) In determining whether a performance-related feature justifies a different standard for a group of products, DOE considers such factors as the utility to the consumer 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. 6316(a); 42 U.S.C. 6295(q)(2))

B. Background

1. Current Standards

DOE most recently completed a review of its distribution transformer standards in a final rule published on April 18, 2013 (''April 2013 Standards Final Rule''), through which DOE prescribed the current energy conservation standards for distribution transformers manufactured on and after January 1, 2016. 78 FR 23336, 23433. These standards are set forth in DOE's regulations at 10 CFR 431.196 and are repeated in Table II.1, Table II.2, and Table II.3.

BILLING CODE 6450–01–P

Table II.1 Federal Energy Efficiency Standards for Low-Voltage Dry-Type Distribution Transformers

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

Table II.2 Federal Energy Conservation Standards for Liquid-Immersed Distribution Transformers

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	99.52

Table II.3 Federal Energy Conservation Standards for Medium-Voltage Dry-Type Distribution Transformers

Single-Phase				Three-Phase			
	BIL				BIL		
	20-45 kV	46-95 kV	≥96 kV		20-45 kV	46-95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.1	97.86		15	97.5	97.18	
25	98.33	98.12		30	97.9	97.63	
37.5	98.49	98.3		45	98.1	97.86	
50	98.6	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	99.2	99.11
833	99.31	99.23	99.20	1500	99.37	99.3	99.21
				2000	99.43	99.36	99.28
				2500	99.47	99.41	99.33

BILLING CODE 6450–01–C

2. History of Standards Rulemaking for Distribution Transformers

On June 18, 2019, DOE published notice that it was initiating an early assessment review to determine whether any new or amended standards would satisfy the relevant requirements of EPCA for a new or amended energy conservation standard for distribution transformers and a request for information (RFI). 84 FR 28239 (''June 2019 Early Assessment Review RFI'').

On August 27, 2021, DOE published a notification of a webinar and availability of a preliminary technical support document (TSD), which announced the availability of its analysis for distribution transformers. 86 FR 48058 (''August 2021 Preliminary Analysis TSD''). The purpose of the August 2021 Preliminary Analysis TSD was to make publicly available the initial technical and economic analyses conducted for distribution transformers, and present initial results of those analyses. DOE did not propose new or amended standards for distribution transformers at that time. The initial TSD and accompanying analytical spreadsheets for the August 2021 Preliminary Analysis TSD provided the analyses DOE used to examine the potential for amending energy conservation standards for distribution transformers and provided preliminary discussions in response to a number of issues raised in comments to the June 2019 Early Assessment Review RFI. It described the analytical methodology that DOE used and each analysis DOE performed.

On January 11, 2023, DOE published a NOPR and public meeting announcement, in which DOE proposed amended energy conservation standards for distribution transformers. 88 FR 1722 (''January 2023 NOPR''). DOE proposed amended standards for liquid-immersed, low-voltage dry-type, and MVDT distribution transformers. DOE additionally proposed to establish a separate equipment class for submersible distribution transformers, with standards maintained at the levels prescribed by the April 2013 Standards Final Rule. *Id.* On February 16, 2023, DOE presented the proposed standards and accompanying analysis in a public meeting.

On February 22, 2023, DOE published a notice extending the comment period for the January 2023 NOPR by an additional 14 days. 88 FR 10856.

DOE received 93 comments in response to the January 2023 NOPR from the interested parties listed in Table II.4.

BILLING CODE 6450–01–P

Table II.4 List of Commenters with Written Submissions in Response to the January 2023 NOPR

Commenter(s)	Abbreviation	Comment No. in the Docket	Commenter Type
Cleveland-Cliffs Steel Corporation	Cliffs	66, 105	Steel Manufacturer
American Public Power Association, Edison Electric Institute, National Rural Electric Cooperative Association	Joint Associates	68	Trade Association
International Union, United Automobile, Aerospace and Agricultural Implement Workers of America	UAW	69	Labor Union
Highline Electric Association	Highline Electric	71	Utility
A. Nichols	Nichols	73	Individual
Mark Strauch	Strauch	74	Individual
GEORG North America Inc.	Georg	76	Manufacturer

Idaho Falls Power	Idaho Falls Power	77	Utility
Consumers Power Inc.	CPI	78	Utility
Allen-Batchelor Construction	Allen-Batchelor Construction	79	Construction/Home Building Organization
Robert Cleveland	Cleveland	80	Individual
Indiana Electric Cooperatives	Indiana Electric Co-Ops	81	Utility Association
Ivey Residential	Ivey Residential	82	Construction/Home Building Organization
Fall River Rural Electric Cooperative Inc.	Fall River	83	Utility
Williams Development Partners, LLC	Williams Dev Partners	84	Construction/Home Building Organization
Central Lincoln	Central Lincoln	85	Utility
Electric Research and Manufacturing Cooperative, Inc.	ERMCO	86	Manufacturer
Southwest Electric	Southwest Electric	87	Manufacturer
U.S. Chamber of Commerce	Chamber of Commerce	88	Lobbying Organization
James Sychak	Sychak	89	Individual
United Auto Workers Locals	UAW Locals	91, 163, 164	Trade Association
WEG Transformers	WEG	92	Manufacturer
Sola Hevi-Duty	SolaHD	93	Manufacturer
Building Industry Association of Washington	BIAW	94	Construction/Home Building Organization
Exelon	Exelon	95	Utility
Mulkey Engineering Inc.	Mulkey Engineering	96	Consultant
National Multifamily Housing Council and National Apartment Association	NMHC & NAA	97	Construction/Home Building Organization
National Rural Electric Cooperative Association	NRECA	98	Utility Association
Power System Engineering	PSE	98	Consultant
Coalition for the Advancement for Reliable Electric Systems	CARES	99	Utility Association
Office of Advocacy of the U.S. Small Business Administration	SBA	100	Elected Official/Agency
Schneider Electric	Schneider	101	Manufacturer
New York State Energy Research and Development Authority	NYSERDA	102	Regional Agency/Association
American Public Power Association	APPA	103	Utility Association
Northwest Public Power Association	NWPPA	104	Utility Association
National Association of Home Builders of the United States	NAHB	106	Construction/Home Building Organization
ABB Inc.	ABB	107	Manufacturer
Leading Builders of America	LBA	108	Construction/Home Building Organization
Standards Michigan	Standards Michigan	109	Regional Agency/Association
ABB Smart Power	ABB SP	110	Manufacturer

EVgo	EVgo	111	Construction/Home Building Organization
Powersmiths International Corp.	Powersmiths	112	Manufacturer
Alabama Senator Tommy Tuberville	Alabama Senator	113	State Official/Agency
Entergy Services, LLC	Entergy	114	Utility
American Iron and Steel Institute	AISI	115	Trade Association
Howard Industries Inc.	Howard	116	Manufacturer
Theresa Pugh Consulting	Pugh Consulting	117	Utility Association
WEC Energy Group	WEC	118	Utility
Metals Technology Consulting	MTC	119	Consultant
Prolec GE	Prolec GE	120	Manufacturer
Appliance Standards Awareness Project, American Council for an Energy-Efficient Economy, Natural Resources Defense Council	Efficiency Advocates	121	Efficiency Organization
American Council for an Energy-Efficient Economy, Climate Action Campaign, Elevate Energy, Environment America, Environmental Defense Fund, Green & Healthy Homes Initiative, Natural Resources Defense Council, U.S. PIRG	Environmental and Climate Advocates	122	Efficiency Organization
Institute for Policy Integrity – New York University School of Law	IPI-NYU	123	Efficiency Organization
California Energy Commission	CEC	124	Efficiency Organization
Metglas, Inc.	Metglas	125	Steel Manufacturer
Rappahannock Electric Cooperative	REC	126	Utility Association
Xcel Energy	Xcel Energy	127	Utility
Alliant Energy	Alliant Energy	128	Utility
Northeast Public Power Association	NEPPA	129	Utility Association
Portland General Electric	Portland General Electric	130	Utility
Butler County Board of Commissioners	BCBC	131, 132	Local Government
Butler County Government Center	BCGC	132	Local Government
B. Webb	Webb	133	Individual
HVOLT Inc.	HVOLT	134	Consultant
Edison Electric Institute	EEI	135	Utility Association
EMS Consulting	EMS Consulting	136	Consultant
Eaton	Eaton	137	Manufacturer
Transformer Manufacturing Association of America	TMMA	138	Trade Association
Idaho Power	Idaho Power	139	Utility
Carte International Inc.	Carte	140	Manufacturer
National Electrical Manufacturers Association	NEMA	141	Trade Association
Hammond Power Solutions Inc.	Hammond	142	Manufacturer
United States Congressman Jake LaTurner	Kansas Congress Member	143	Elected Official/Agency
Tennessee Valley Public Power Association	TVPPA	144	Utility Association

United States Representative Dusty Johnson	South Dakota Congress Member	145	Elected Official/Agency
Joint United States Senators	U.S. Senators	147	Elected Official/Agency
Virginia, Maryland, and Delaware United States Members of Congress	VA, MD, and DE Members of Congress	148	Elected Official/Agency
United States Representative Morgan Luttrell	Texas Congress Member	149	Elected Official/Agency
United States Members of Congress from Florida	Florida Members of Congress	150	Elected Official/Agency
United States Representative Marcy Kaptur	Ohio Congress Member	151	Elected Official/Agency
United States Members of Congress from Michigan	Michigan Members of Congress	152	Elected Official/Agency
United States Members of Congress from New York	New York Members of Congress	153	Elected Official/Agency
American Council for an Energy-Efficient Economy, Appliance Standards Awareness Project, Earth Justice, Electrify Now, American Council for an Energy-Efficient Economy, Evergreen Action, League of Conservation Voters, Midwest Building Decarbonization Coalition, Natural Resources Defense Council, Phius, Rewiring America, RMI, Sierra Club, Union of Concerned Scientists	Efficiency and Climate Advocates	154	Efficiency Organization
J. Thomas	Thomas	155	Individual
Pennsylvania AFL-CIO	Pennsylvania AFL-CIO	156	Trade Association
Individual	Nelson	157	Individual
Butler Country Chamber of Commerce	BCCC	158	Local Government
Renick Brothers Construction Co.	Renick Brothers Co.	160	Construction/Home Building Organization
Snyder Associated Companies Inc.	Snyder Companies	161	Local Business

BILLING CODE 6450–01–C

A parenthetical reference at the end of a comment quotation or paraphrase provides the location of the item in the public record.[34] To the extent that interested parties have provided written comments that are substantively consistent with any oral comments provided during the February 16, 2023, public meeting, DOE cites the written comments throughout this final rule. Any oral comments provided during the webinar that are not substantively addressed by written comments are summarized and cited separately throughout this final rule.

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

III. General Discussion

DOE developed this final rule after a review of the market for the subject distribution transformers. DOE also considered comments, data, and information from interested parties that represent a variety of interests. This notice addresses issues raised by these commenters.

A. General Comments

This section summarizes general comments received from interested parties regarding rulemaking timing and process.

DOE received several comments recommending DOE pursue policies for saving energy or strengthening the supply chain either in place of or in addition to revised distribution transformer efficiency standards. Specifically, Standards Michigan commented that distribution transformers are oversized and recommended DOE work with electrical code committees to encourage proper distribution transformer sizing. (Standards Michigan, No. 109 at p. 1) APPA recommended DOE consider other efficiency measures to conserve energy, such as improving building codes and increasing the size of service conductors to reduce transmission losses. (APPA, No. 103 at p. 3) Pugh Consulting commented that DOE should work with the U.S. Environmental Protection Agency (EPA) to accelerate the permitting process under the Clean Air Act and Clean Water Act and to allow steel and transformer manufacturers to engage in nitrogen oxide (NOx) emission trading under EPA's Good Neighbor Plan. (Pugh Consulting, No. 117 at p. 7) Pugh Consulting further recommended DOE remove tariffs from friendly nations and explore agreements to increase electrical steel imports from these nations. (Pugh Consulting, No. 117 at p. 7) EVgo commented that DOE should use Defense Production Act investments to increase transformer supply to accommodate the increases in demand that are supporting administration electrification goals. (EVgo, No. 111 at p. 2)

DOE notes that this final rule pertains only to energy conservation standards for distribution transformers, and any efforts to amend national electrical codes, building codes, or other Federal regulatory programs and policies are beyond the scope of this rulemaking. DOE notes it is actively working with fellow government agencies and industry to better address the current supply chain challenges impacting the distribution transformer market, as well as the broader electricity industry.[35]

Several commenters disagreed with DOE's assessment that the proposed standards are technologically feasible and economically justified generally.

Cliffs commented that DOE standards are not economically justified. (Cliffs, No. 105 at pp. 13–14) NAHB commented that the proposed standards are not economically justified because the benefits do not outweigh the costs. NAHB added that DOE's designation of economic justification is subjective and would be impacted by regulations from other agencies. (NAHB, No. 106 at pp. 2–3) SBA commented that the proposed standards are not economically justified due to the additional costs associated with amorphous cores and the significant shock to the market from a lack of market competition. (SBA, No. 100 at pp. 6–7) NRECA commented that the proposed standards are neither economically justified nor technologically feasible because DOE's NOPR is based on flawed assumptions. (NRECA, No. 98 at pp. 1–2) Pugh Consulting commented that DOE's proposal does not properly consider the requirements established under the Energy Policy Act of 2005. (Pugh Consulting, No. 117 at p. 2)

APPA commented that DOE's requests for comment in the January 2023 NOPR indicate some technical questions are unresolved and, therefore, DOE should address these questions before issuing any final rule. (APPA, No. 103 at pp. 17–18) Cliffs commented that insufficient collaboration with stakeholders was conducted prior to publication of the NOPR and because of that, the NOPR contains flawed assumptions and oversteps DOE's authority. (Cliffs, No. 105 at p. 2)

Entergy recommended that instead of finalizing the proposed rule, DOE should (1) adopt a standard that does not require a full move to amorphous or (2) use its authority to issue a determination that no new standard is required, which would allow DOE to work with industry through the Electricity Subsector Coordinating Council (ESCC) to further study the cost and benefits of enacting this rule and return with recommendations prior to 2027. (Entergy, No. 114 at p. 4)

CEC commented that DOE should ensure it adopts a final rule by June 30, 2024, because EPCA required DOE to update this standard by April 2019. (CEC, No. 124 at p. 2)

As stated, DOE has provided numerous notices with extensive comment periods to ensure stakeholders have an opportunity to provide data and to identify or correct any concerns in DOE's analysis of amended energy conservation standards. DOE has reviewed the many comments, data, and feedback received in response to the January 2023 NOPR and updated its analysis based on this information, as discussed throughout this final rule. In this final rule, DOE is adopting efficiency standards based on, but importantly different from, those proposed in the January 2023 NOPR. DOE is adopting standards that are expected to require significantly less amorphous material and extend the compliance period by two years, relative to what was proposed, which will reduce the burden on manufacturers and allow manufacturers considerable flexibility to meet standards without near-term supply chain impacts. DOE has concluded that the amended standards adopted in this final rule are technologically feasible and economically justified. A detailed discussion of DOE's analysis and conclusion is provided in section V.C of this document.

Specific comments regarding DOE's analysis are discussed in further detail below.

B. Equipment Classes and Scope of Coverage

This final rule covers the COMMERCIAL AND INDUSTRIAL equipment that meet the definition of ''distribution transformer'' as codified at 10 CFR 431.192.

When evaluating and establishing energy conservation standards, DOE divides covered products into equipment classes by the type of energy used or by capacity or other performance-related features that justify different standards. In making a determination whether a performance-related feature justifies a different standard, DOE must consider the utility of the feature to the consumer and other factors DOE determines are appropriate. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)) The distribution transformer equipment classes considered in this final rule are discussed in detail in section IV.A.2 of this document.

This final rule covers distribution transformers, which are currently defined as a transformer that (1) has an input voltage of 34.5 kV or less; (2) has an output voltage of 600 V or less; (3) is rated for operation at a frequency of 60 Hz; and (4) has a capacity of 10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units; but (5) the term ''distribution transformer'' does not include a transformer that is an autotransformer; drive (isolation) transformer; grounding transformer; machine-tool (control) transformer; non-ventilated transformer; rectifier transformer; regulating transformer; sealed transformer; special-impedance transformer; testing transformer; transformer with tap range of 20 percent or more; uninterruptible power supply transformer; or welding transformer. 10 CFR 431.192.

See section IV.A.1 of this document for discussion of the scope of coverage and product classes analyzed in this final rule.

C. Test Procedure

EPCA sets forth generally applicable criteria and procedures for DOE's adoption and amendment of test procedures. (42 U.S.C. 6314(a)) Manufacturers of covered equipment must use these test procedures as the basis for certifying to DOE that their product complies with the applicable energy conservation standards and as the basis for any representations regarding the energy use or energy efficiency of the equipment. (42 U.S.C. 6316(e)(1); 42 U.S.C. 6295(s); and 42 U.S.C. 6314(d)). Similarly, DOE must use these test procedures to evaluate whether a basic model complies with

[35] *See* Department of Energy. *DOE Actions to Unlock Transformers and Grid Component Production.* Available at *www.energy.gov/policy/articles/doe-actions-unlock-transformer-and-grid-component-production* (accessed Oct. 27, 2023).

the applicable energy conservation standard(s). 10 CFR 429.110(e). The current test procedure for distribution transformers is codified at 10 CFR part 431, subpart K, appendix A (''appendix A''). Appendix A includes provisions for determining percentage efficiency at rated per-unit load (PUL), the metric on which current standards are based. 10 CFR 431.193.

On September 14, 2021, DOE published a test procedure final rule for distribution transformers that contained revised definitions for certain terms, updated provisions based on the latest versions of relevant industry test standards, maintained PUL for the certification of efficiency, and added provisions for representing efficiency at alternative PULs and reference temperatures. 86 FR 51230 (''September 2021 TP Final Rule''). DOE determined that the amendments to the test procedure adopted in the September 2021 TP Final Rule do not alter the measured efficiency of distribution transformers or require retesting or recertification solely as a result of DOE's adoption of the amendments to the test procedure. 86 FR 51230, 51249.

Carte commented that they are not sure how to report data for a transformer with a dual-rated kVA based on the division of single-phase and three-phase power. (Carte, No. 140 at p. 9)

For distribution transformers, efficiency must be determined for each basic model, as defined in 10 CFR 431.192. Questions regarding how to report data for a specific unit can be submitted to *ApplianceStandardsQuestions@ee.doe.gov.*

Eaton commented that if DOE adopts higher efficiency standards, DOE should revisit the alternative methods for determining energy efficiency and energy use (AEDM) tolerance requirements in 10 CFR 429.70, because the original tolerances were based on a much higher number of absolute losses and amended standards would be based on a much smaller number of losses. (Eaton, No. 137 at pp. 29–30) Therefore, even though the difference in watts of loss could be similar, the percentage difference in losses may exceed the current requirements in 10 CFR 429.70. *Id.*

DOE notes that AEDM requirements are handled in a separate rulemaking that spans all certification, labeling, and enforcement provisions across many products and equipment (*see* Docket No. EERE–2023–BT–CE–0001). AEDMs are widely used in certifying the efficiency of distribution transformers and DOE intends to continue to allow this under amended efficiency standards. DOE encourages stakeholders to submit any comment and data regarding distribution transformer AEDM tolerances to the docket referenced above.

D. Technological Feasibility

1. General

As discussed, any new or amended energy conservation standard must be designed to achieve the maximum improvement in energy efficiency that DOE determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A))

To determine whether potential amended standards would be technologically feasible, DOE first develops a list of all known technologies and design options that could improve the efficiency of the products or equipment that are the subject of the rulemaking. DOE considers technologies incorporated in commercially available products or in working prototypes to be ''technologically feasible.'' 10 CFR 431.4; 10 CFR 430, subpart C, appendix A, sections 6(b)(3)(i) and 7(b)(1). Section IV.A.3 of this document discusses the technology options identified by DOE for this analysis. For further details on the technology assessment conducted for this final rule, see chapter 3 of the final rule TSD.

After DOE has determined which, if any, technologies and design options are technologically feasible, it further evaluates each technology and design option in light of the following additional screening criteria: (1) practicability to manufacture, install, and service; (2) adverse impacts on product utility or availability; (3) adverse impacts on health or safety; and (4) unique-pathway proprietary technologies. 10 CFR 431.4; 10 CFR 430, subpart C, appendix A, sections 6(b)(3)(ii) through(v) and 7(b)(2) through(5). Those technology options that are ''screened out'' based on these criteria are not considered further. Those technology and design options that are not screened out are considered as the basis for higher efficiency levels that DOE could consider for potential amended standards. Section IV.B of this document discusses the results of this screening analysis conducted for this final rule. For further details on the screening analysis conducted for this final rule, see chapter 4 of the final rule TSD.

2. Maximum Technologically Feasible Levels

EPCA requires that for any proposed rule that prescribes an amended or new energy conservation standard, or prescribes no amendment or no new standard for a type (or class) of covered product, DOE must determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible for each type (or class) of covered products. (42 U.S.C. 6313(a); 42 U.S.C. 6295(p)(1)). Accordingly, in the engineering analysis, DOE identifies the maximum efficiency level currently available on the market. DOE also defines a ''max-tech'' efficiency level, representing the maximum theoretical efficiency that can be achieved through the application of all available technology options retained from the screening analysis.[36] In many cases, the max-tech efficiency level is not commercially available because it is not currently economically feasible.

E. Energy Savings

1. Determination of Savings

For each trial standard level (TSL), DOE projected energy savings from application of the TSL to distribution transformers purchased in the 30-year period that begins in the year of compliance with the amended standards (2029–2058).[37] The savings are measured over the entire lifetime of equipment purchased in the 30-year analysis period. DOE quantified the energy savings attributable to each TSL as the difference in energy consumption between each standards case and the no-new-standards case. The no-new-standards case represents a projection of energy consumption that reflects how the market for a product would likely evolve in the absence of amended energy conservation standards.

DOE used its national impact analysis (NIA) spreadsheet models to estimate national energy savings (NES) from potential amended standards for distribution transformers. The NIA spreadsheet model (described in section IV.H of this document) calculates energy savings in terms of site energy, which is the energy directly consumed by products at the locations where they are used. For electricity, DOE reports national energy savings in terms of primary energy savings, which is the savings in the energy that is used to generate and transmit the site electricity. For natural gas, the primary energy savings are considered to be

[36] In applying these design options, DOE would only include those that are compatible with each other that when combined, would represent the theoretical maximum possible efficiency.

[37] DOE also presents a sensitivity analysis that considers impacts for products shipped in a 9-year period. *See* section V.B.3 of this document for additional detail.

equal to the site energy savings. DOE also calculates NES in terms of FFC energy savings. The FFC metric includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and thus presents a more complete picture of the impacts of energy conservation standards.[38] DOE's approach is based on the calculation of an FFC multiplier for each of the energy types used by covered products or equipment. For more information on FFC energy savings, see section IV.H.2 of this document.

2. Significance of Savings

To adopt any new or amended standards for a covered product, DOE must determine that such action would result in significant energy savings. (42 U.S.C. 6295(o)(3)(B))

The significance of energy savings offered by a new or amended energy conservation standard cannot be determined without knowledge of the specific circumstances surrounding a given rulemaking.[39] For example, some covered products and equipment have most of their energy consumption occur during periods of peak energy demand. The impacts of these products on the energy infrastructure can be more pronounced than products with relatively constant demand. Accordingly, DOE evaluates the significance of energy savings on a case-by-case basis, taking into account the significance of cumulative FFC national energy savings, the cumulative FFC emissions reductions, and the need to confront the global climate crisis, among other factors.

As stated, the standard levels adopted in this final rule for all distribution transformers are projected to result in national energy savings of 4.58 quad, the equivalent of the primary annual energy use of 49.2 million homes . Based on the amount of FFC savings, the corresponding reduction in emissions, and the need to confront the global climate crisis, DOE has determined the energy savings from the standard levels adopted in this final rule are ''significant'' within the meaning of 42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B).

[38] The FFC metric is discussed in DOE's statement of policy and notice of policy amendment. 76 FR 51282 (Aug. 18, 2011), as amended at 77 FR 49701 (Aug. 17, 2012).

[39] The numeric threshold for determining the significance of energy savings established in a final rule published on February 14, 2020 (85 FR 8626, 8670), was subsequently eliminated in a final rule published on December 13, 2021 (86 FR 70892).

F. Economic Justification

1. Specific Criteria

As noted previously, EPCA provides seven factors to be evaluated in determining whether a potential energy conservation standard is economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII)) The following sections discuss how DOE has addressed each of those seven factors in this rulemaking.

a. Economic Impact on Manufacturers and Consumers

In determining the impacts of potential new or amended standards on manufacturers, DOE conducts an MIA, as discussed in section IV.J. DOE first uses an annual cash flow approach to determine the quantitative impacts. This step includes both a short-term assessment—based on the cost and capital requirements during the period between when a regulation is issued and when entities must comply with the regulation—and a long-term assessment over a 30-year period. The industry-wide impacts analyzed include (1) INPV, which values the industry on the basis of expected future cash flows; (2) cash flows by year; (3) changes in revenue and income; and (4) other measures of impact, as appropriate. Second, DOE analyzes and reports the impacts on different types of manufacturers, including impacts on small manufacturers. 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 consumers, measures of economic impact include the changes in LCC and PBP associated with new or amended standards. These measures are discussed further in the following section. For consumers in the aggregate, DOE also calculates the national net present value of the consumer costs and benefits expected to result from particular standards. DOE also evaluates the impacts of potential standards on identifiable subgroups of consumers that may be affected disproportionately by a standard.

b. Savings in Operating Costs Compared to Increase in Price (LCC and PBP)

EPCA requires DOE to consider the savings in operating costs throughout the estimated average life of the covered product in the type (or class) compared to any increase in the price of, or in the initial charges for, or maintenance expenses of, the covered product that are likely to result from a standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(II)) DOE conducts this comparison in its LCC and PBP analysis.

The LCC is the sum of the purchase price of a product (including its installation) and the operating cost (including energy, maintenance, and repair expenditures) discounted over the lifetime of the product. The LCC analysis requires a variety of inputs, such as product prices, product energy consumption, energy prices, maintenance and repair costs, product lifetime, and discount rates appropriate for consumers. To account for uncertainty and variability in specific inputs, such as product lifetime and discount rate, DOE uses a distribution of values, with probabilities attached to each value.

The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost due to a more stringent standard by the change in annual operating cost for the year that standards are assumed to take effect.

For its LCC and PBP analysis, DOE assumes that consumers will purchase the covered equipment in the first year of compliance with new or amended standards. The LCC savings for the considered efficiency levels are calculated relative to the case that reflects projected market trends in the absence of new or amended standards. DOE's LCC and PBP analysis is discussed in further detail in section IV.F.

c. Energy Savings

Although significant conservation of energy is a separate statutory requirement for adopting an energy conservation standard, EPCA requires DOE, in determining the economic justification of a standard, to consider the total projected energy savings that are expected to result directly from the standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(III)) As discussed in section IV.H, DOE uses the NIA spreadsheet models to project national energy savings.

d. Lessening of Utility or Performance of Products

In establishing equipment classes, and in evaluating design options and the impact of potential standard levels, DOE evaluates potential standards that would not lessen the utility or performance of the considered equipment. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(IV)) Based on data available to DOE, the standards adopted in this document would not reduce the utility or performance of the equipment under consideration in this rulemaking.

e. Impact of Any Lessening of Competition

EPCA directs DOE to consider the impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from a standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(V)) It also directs the Attorney General to determine the impact, if any, of any lessening of competition likely to result from a standard and to transmit such determination to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(ii))

NAHB expressed concern that DOE has not published the determination made by the Attorney General on the impact of any lessening of competition that may result from this rule and recommended DOE withdraw its proposal until stakeholders have had the opportunity to review this document. (NAHB, No. 106 at p. 2)

Under EPCA, the Attorney General is required to make a determination of the impact, if any, of any lessening of competition likely to result from such standard no later than 60 days after publication of the proposed rule. DOE is then required to publish any such determination in the **Federal Register**. To assist the Department of Justice (DOJ) in making such a determination, DOE transmitted copies of its proposed rule and the NOPR TSD to the Attorney General for review, with a request that the DOJ provide its determination on this issue. In its assessment letter responding to DOE, DOJ concluded that the proposed energy conservation standards for distribution transformers are unlikely to have a significant adverse impact on competition. In accordance with EPCA, DOE is publishing the Attorney General's assessment at the end of this final rule.

f. Need for National Energy Conservation

DOE also considers the need for national energy and water conservation in determining whether a new or amended standard is economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(VI)) The energy savings from the adopted standards are likely to provide improvements to the security and reliability of the Nation's energy system. Reductions in the demand for electricity also may result in reduced costs for maintaining the reliability of the Nation's electricity system. DOE conducts a utility impact analysis to estimate how standards may affect the Nation's needed power generation capacity, as discussed in section IV.M of this document.

DOE maintains that environmental and public health benefits associated with the more efficient use of energy are important to take into account when considering the need for national energy conservation. The adopted standards are likely to result in environmental benefits in the form of reduced emissions of air pollutants and GHGs associated with energy production and use. DOE conducts an emissions analysis to estimate how potential standards may affect these emissions, as discussed in section IV.K of this document; the estimated emissions impacts are reported in section V.B.6 of this document. DOE also estimates the economic value of emissions reductions resulting from the considered TSLs, as discussed in section IV.L of this document.

g. Other Factors

In determining whether an energy conservation standard is economically justified, DOE may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(VII)) To the extent DOE identifies any relevant information regarding economic justification that does not fit into the other categories described previously, DOE could consider such information under ''other factors.''

2. Rebuttable Presumption

EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the equipment that meets the standard is less than three times the value of the first year's energy savings resulting from the standard, as calculated under the applicable DOE test procedure. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(iii)) DOE's LCC and PBP analyses generate values used to calculate the effect potential amended energy conservation standards would have on the PBP for consumers. These analyses include, but are not limited to, the 3-year PBP contemplated under the rebuttable-presumption test. In addition, DOE routinely conducts an economic analysis that considers the full range of impacts to consumers, manufacturers, the Nation, and the environment, as required under 42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i). The results of this analysis serve as the basis for DOE's evaluation of the economic justification for a potential standard level (thereby supporting or rebutting the results of any preliminary determination of economic justification). The rebuttable presumption payback calculation is discussed in section IV.F.11 of this final rule.

IV. Methodology and Discussion of Related Comments

This section addresses the analyses DOE has performed for this rulemaking with regard to distribution transformers. Separate subsections address each component of DOE's analyses.

DOE used several analytical tools to estimate the impact of the standards considered in this document. The first tool is a spreadsheet that calculates the LCC savings and PBP of potential amended or new energy conservation standards. The national impacts analysis uses a second spreadsheet set that provides shipments projections and calculates national energy savings and net present value of total consumer costs and savings expected to result from potential energy conservation standards. DOE uses the third spreadsheet tool, the Government Regulatory Impact Model (GRIM), to assess manufacturer impacts of potential standards. These three spreadsheet tools are available on the DOE website for this rulemaking: *www.regulations.gov/docket/EERE-2019-BT-STD-0018.* Additionally, DOE used output from the latest version of the Energy Information Administration's (EIA's) *Annual Energy Outlook* (*AEO*) for the emissions and utility impact analyses.

A. Market and Technology Assessment

DOE develops information in the market and technology assessment that provides an overall picture of the market for the products concerned, including the purpose of the products, the industry structure, manufacturers, market characteristics, and technologies used in the products. 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 include (1) a determination of the scope of the rulemaking and product classes, (2) manufacturers and industry structure, (3) existing efficiency programs, (4) shipments information, (5) market and industry trends, and (6) technologies or design options that could improve the energy efficiency of distribution transformers.

The key findings of DOE's market assessment are summarized in the following sections. See chapter 3 of the final rule TSD for further discussion of the market and technology assessment.

1. Scope of Coverage

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

Distribution transformer means a transformer that—(1) has an input voltage of 34.5 kV or less; (2) has an output voltage of 600 V or less; (3) is rated for operation at a 60 Hz; and (4) has a capacity of 10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units; but (5) The term ''distribution transformer'' does not include a transformer that is an—(i) autotransformer; (ii) drive (isolation) transformer; (iii) grounding transformer; (iv) machine-tool (control) transformer; (v) non-ventilated; (vi) rectifier transformer; (vii) regulating transformer; (viii) sealed transformer; (ix) special-impedance transformer; (x) testing transformer; (xi) transformer with tap range of 20 percent or more; (xii) uninterruptible power supply transformer; or (xiii) Welding transformer.

In the January 2023 NOPR, DOE discussed and proposed minor edits to the definitions of equipment excluded from the definition of distribution transformer. In response to the January 2023 NOPR, DOE received additional comments on its proposed definitional edits. These detailed comments are discussed below.

a. Autotransformers

The EPCA definition of distribution transformer excludes ''a transformer that is designed to be used in a special purpose application and is unlikely to be used in general purpose applications, such as . . . [an] auto-transformer . . .''. (42 U.S.C. 6291(35)(b)(ii)) DOE has defined autotransformer as ''a transformer that: (1) has one physical winding that consists of a series winding part and a common winding part; (2) has no isolation between its primary and secondary circuits; and (3) during step-down operation, has a primary voltage that is equal to the total of the series and common winding voltages, and a secondary voltage that is equal to the common winding voltage.'' 10 CFR 431.192.

In the January 2023 NOPR, DOE noted that, while stakeholders suggested that there may be certain applications for which autotransformers may be substitutable for an isolation transformer, these substitutions would be limited to specific applications and not common enough to regard as general practice. 88 FR 1722, 1741. Further, DOE stated that, because autotransformers do not provide galvanic isolation, they are unlikely to be used in at least some general-purpose applications. DOE did not propose to amend the exclusion of autotransformers under the distribution transformer definition. *Id.*

Schneider commented that autotransformers were used in the 1970's for distribution application. However, they do not allow for the creation of a neutral on the secondary side of the transformer nor do they allow for isolating the secondary and primary windings for power quality benefits. (Schneider, No. 101 at p. 15) Schneider commented that for applications with small loads, based on the increased purchase price and footprints at the proposed efficiency levels, the market will begin evaluating autotransformers and applying them to certain distribution applications. *Id.* Schneider recommended the statutory definition of low-voltage transformer be modified through legislation to subject autotransformers to energy conservation standards. *Id.* at p. 17.

DOE agrees that in certain applications, autotransformers may be capable of serving as a replacement for general purpose transformers. However, as discussed, the isolation and power quality benefits of distribution transformers make it unlikely that autotransformers would be widely viewed or used as a substitute for most general purpose distribution transformers. DOE notes that manufacturer literature already markets autotransformers as an ''economical alternative to general purpose distribution isolation transformers to adjust the supply voltage to match specific load requirements when load isolation from the supply line is not required.'' [40] As noted in the marketing, autotransformers are only suitable in transformer applications where load isolation is not required.

Despite autotransformers being less expensive, having a smaller footprint than general purpose distribution transformers, and being marketed as suitable in certain applications, autotransformers have not seen widespread use in general purpose applications and their use has been limited to special purposes. While autotransformers may be capable of meeting similar efficiency regulations as general purpose distribution transformers, they are statutorily excluded from the definition of distribution transformer on account of being reserved for special purpose applications. Further, stakeholder comments reiterate that there are legitimate shortcomings of autotransformer that makes significant substitution unlikely. Based on this feedback, DOE has concluded that autotransformers are designed to be used in a special purpose application and are unlikely to be used in general purpose applications due to these shortcomings. Therefore, DOE is not amending the exclusion of autotransformers under the distribution transformer definition. DOE will continue to evaluate the extent to which autotransformers are used in general purpose applications in future rulemakings.

b. Drive (Isolation) Transformers

The EPCA definition of distribution transformer excludes a transformer that is designed to be used in a special purpose application and is unlikely to be used in general purpose applications, such as drive transformers. (42 U.S.C. 6291(35)(b)(ii)). DOE defines a drive (isolation) transformer as a ''transformer that (1) isolates an electric motor from the line; (2) accommodates the added loads of drive-created harmonics; and (3) is designed to withstand the mechanical stresses resulting from an alternating current adjustable frequency motor drive or a direct current motor drive.'' 10 CFR 431.192.

In the January 2023 NOPR, DOE responded to comments by Schneider and Eaton submitted on the August 2021 Preliminary Analysis TSD that claimed drive-isolation transformers have historically been sold with non-standard low-voltage ratings corresponding to typical motor input voltages, and as such were unlikely to be used in general-purpose applications. (Schneider, No. 49 at p. 3; Eaton, No. 55 at p. 3) Schneider and Eaton commented that they had seen a recent increase in drive-isolation transformers specified as having either a ''480Y/277'' or ''208Y/120'' voltage secondary, making it more difficult to ascertain whether these transformers were being used in general purpose applications. (Schneider, No. 49 at p. 3; Eaton, No. 55 at p. 3)

In response to these comments, DOE noted that while some drive-isolation transformers could, in theory, be used in general purpose applications, no evidence exists to suggest this is common practice. 88 FR 1722, 1742.

[40] Hammond Power Solutions. *Autotransformers,* 2023. *documents.hammondpowersolutions.com/documents/Literature/Specialty/HPS-Autotransformers-Brochure.pdf?_gl=1*db1907*_ga*NTA0ODk1MjQzLjE2NzExMzEzMTM.*_ga_RTZEGSXND8*MTY4MzIxNTc5My42Ni4xLjE2ODMyMTcyNjcuNTguMC4w.*

Therefore, DOE concluded that drive-isolation transformers remain an example of a transformer that is designed to be used in special purpose applications and excluded by statute. However, DOE also noted that the overwhelming majority of general purpose applications use either 208Y/120 or 480Y/277 voltage while the overwhelming majority of drive-isolation transformers are designed with alternative voltages designed to match specific motor drives. *Id.* Therefore, DOE stated that a drive-isolation transformer with a rated secondary voltage of 208Y/120 or 480Y/277 is considerably more likely to be used in general purpose applications.

DOE proposed to amend the definition of drive (isolation) transformer to include the criterion that drive-isolation transformers have an output voltage other than 208Y/120 and 480Y/277. 88 FR 1722, 1742. DOE requested comment on its determination that a drive-isolation transformer with these common voltage ratings is likely to be used in general purpose applications and if any other common voltage ratings would indicate likely use in general purpose applications. *Id.*

In response, Schneider commented that it agrees with the evaluation completed by DOE and the proposed definition. (Schneider, No. 101 at p. 3) Schneider recommended Congress modify the statutory definition of LVDT distribution transformer to include all six-pulse drive-isolation transformers. (Schneider, No. 101 at p. 17) Schneider further commented that even if customers do need a secondary 208Y/120 or 480Y/277 voltage for their drive applications, they would still be able to purchase a transformer, but it would just be an energy efficient model. (Schneider, No. 101 at p. 3) Schneider has previously commented that six-pulse drive-isolation transformers are within the LVDT scope in Canada and their energy conservation standards align with current DOE energy conservation standards. (Schneider, No. 49 at p. 4) Therefore, energy efficient models are readily available for purchase.

NEMA commented that voltage ratings are a poor measure to capture the distinction between general purpose applications and special purpose applications. (NEMA, No. 141 at p. 7) NEMA did not provide an alternative recommendation.

DOE has previously stated that it intends to strictly and narrowly construe the exclusions from the definition of ''distribution transformer.'' 84 FR 24972, 24979 (April 27, 2009). Drive-isolation transformers are excluded from the definition of distribution transformers because 42 U.S.C. 6291 lists them as a special purpose product unlikely to be used in general purpose applications. (42 U.S.C. 6291(35)(b)(ii)) Therefore, even if all six-pulse drive-isolation transformers may be able to meet energy conservation standards, most drive-isolation transformers remain statutorily excluded since they are designed to be used in special purpose applications and are unlikely to be used in a general purpose application. To the extent that some transformers are marketed as drive-isolation transformers with rated output voltages aligning with common distribution voltages, DOE is unable to similarly conclude that these transformers are designed to be used in special purpose applications and are unlikely to be used in general purpose applications.

While NEMA commented that relying on output voltages may not capture the distinctions between all drive-isolation transformers and distribution transformers, NEMA did not provide any data to refute DOE's tentative determination that a transformer marketed as a drive-isolation transformer with rated output voltages aligning with common distribution voltages would be significantly more likely to be used in general purpose distribution applications. Further, as stated by Schneider, DOE's proposal does not prevent consumers that need these secondary voltages for their drive applications from purchasing a suitable product, it only requires them to purchase a product that meets energy conservation standards.

Based on the foregoing discussion, DOE is finalizing its proposed definition for drive (isolation) transformer to mean ''a transformer that: (1) isolates an electric motor from the line; (2) accommodates the added loads of drive-created harmonics; (3) is designed to withstand the additional mechanical stresses resulting from an alternating current adjustable frequency motor drive or a direct current motor drive; and (4) has a rated output voltage that is neither '208Y/120' nor '480Y/277'.''

c. Special-Impedance Transformers

Impedance is an electrical property that relates voltage across and current through a distribution transformer. It may be selected to balance voltage drop, overvoltage tolerance, and compatibility with other elements of the local electrical distribution system. A transformer built to operate outside of the normal impedance range for that transformer's kVA rating, as specified in Tables 1 and 2 of 10 CFR 431.192 under the definition of ''special-impedance transformer,'' is excluded from the definition of ''distribution transformer.'' 10 CFR 431.192.

In the January 2023 NOPR, DOE noted that the current tables in the ''special-impedance transformer'' definition do not explicitly address how to treat non-standard kVA values (*e.g.,* kVA values between those listed in the ''special-impedance transformer'' definition). 88 FR 1722, 1742–1743. DOE proposed to amend the definition of ''special-impedance transformer'' to specify that ''distribution transformers with kVA ratings not appearing in the tables shall have their minimum normal impedance and maximum normal impedance determined by linear interpolation of the kVA and minimum and maximum impedances, respectively, of the values immediately above and below that kVA rating.'' *Id.* DOE noted that this approach was consistent with the approach specified for determining the efficiency requirements of distribution transformers of non-standard kVA rating (*i.e.,* using a linear interpolation from the nearest bounding kVA values listed in the table). *See* 10 CFR 431.196. DOE requested comment on this proposed amendment and whether it provided sufficient clarity as to how to treat the normal impedance ranges for non-standard kVA distribution transformers. *Id.*

In response to the January 2023 NOPR, Prolec GE commented that the proposed definition is a helpful clarification. (Prolec GE, No. 120 at p. 5). NEMA, Howard, and Eaton all recommended DOE specify normal impedance for kVA ranges rather than using a linear interpolation method. (NEMA, No. 141 at pp. 7–8; Howard, No. 116 at pp. 6–7; Eaton, No. 137 at pp. 5–11)

Eaton further commented that the industry assumption was that a given impedance range was intended to apply to all non-standard kVA ratings occurring between two standard kVA ratings and the confusion was as to whether the impedance ranged corresponding to the lower, or the upper preferred kVA rating should be used. (Eaton, No. 137 at p. 5) Eaton identified two potential approaches, the ascending approach, wherein the impedance range is intended to change only upon reaching the next higher preferred kVA, and the descending approach, wherein the impedance range is intended to change immediately upon exceeding the lower kVA rating. (Eaton, No. 137 at pp. 5–7). Eaton commented that the normal impedance ranges change gradually with the only significant jump being between 500 to 666 kVA single-phase and 500 to 749 kVA three-phase, where the lower bound of the normal impedance range jumps from 1.0 percent to 5.0 percent. (Eaton, No. 137 at p. 7)

Eaton provided shipment data for years 2016 through 2022 for non-standard kVAs that coincide with this jump in the lower-bound of normal impedance. (Eaton, No. 137 at pp. 7–8) Eaton commented that they built zero non-standard kVA single-phase units between 501 and 666 kVA and 80 non-standard kVA three-phase units. Eaton added that of those 80 units, 57 were outside of scope regardless of the impedance, while the remaining 23 units were treated as within DOE's scope of coverage. *Id.* Of those units, only seven units were between 1.5 and 5.0 percent impedance. Meaning under the ascending interpretation, these seven units would be in-scope and under the descending interpretation, these seven units would be out of scope. Eaton provided the impedance for all 23 units. *Id.* DOE notes that all 23 units would be within scope under both the ascending interpretation and the proposed linear interpolation method, as the unit impedance values fall within the normal impedance range of both the ascending interpretation and the proposed linear interpolation method.

Eaton commented that current industry standards do not provide a clear answer but in comparing the ascending interpretation and the proposed linear interpolation, the linear interpolation is somewhat more computationally cumbersome and more confusing to audit. (Eaton, No. 137 at pp. 8–11) For these reasons, Eaton recommended DOE adopt normal-impedance tables with an ascending interpretation on kVA ranges. (Eaton, No. 137 at p. 11).

While Howard and NEMA didn't explicitly discuss the differences between the ascending interpretation, descending interpretation, and linear-interpolation methods, both recommended tables that apply the ascending interpretation. (NEMA, No. 141 at pp. 7–8; Howard, No. 116 at pp. 6–7)

As noted, DOE has not previously stated what the normal impedance ranges for non-standard kVA transformers are intended to be. While DOE proposed a linear interpolation, Eaton's data suggested that adopting an ascending interpretation would include an identical number of transformers within scope of the distribution transformer rulemaking. Further, multiple stakeholders preferred the simplicity of the ascending interpretation. Given that the number of impacted transformers is unchanged, the simplicity of defining normal impedance based on kVA ranges, and stakeholder support for the ascending interpretation, DOE is adopting amended tables to specify the normal impedance ranges for non-standard kVA transformers using an ascending interpretation. The adopted normal impedance ranges for each kVA range are given in Table IV.1 and Table IV.2.

Table IV.1 Normal Impedance Ranges for Liquid-Immersed Transformers

Single-phase transformers		Three-phase transformers	
kVA	Impedance (%)	kVA	Impedance (%)
10 <= kVA < 50	1.0 – 4.5	15 <= kVA < 75	1.0 – 4.5
50 <= kVA < 250	1.5 – 4.5	75 <= kVA < 112.5	1.0 – 5.0
250 <= kVA < 500	1.5 – 6.0	112.5 <= kVA < 500	1.2 – 6.0
500 <= kVA < 667	1.5 – 7.0	500 <= kVA < 750	1.5 – 7.0
667 <= kVA <= 833	5.0 – 7.5	750 <= kVA <= 5000	5.0 – 7.5

Table IV.2 Normal Impedance Ranges for Dry-Type Transformers

Single-phase transformers		Three-phase transformers	
kVA	Impedance (%)	kVA	Impedance (%)
15 <= kVA < 75	1.5 – 6.0	15 <= kVA < 225	1.5 – 6.0
75 <= kVA < 167	2.0 – 7.0	225 <= kVA < 500	3.0 – 7.0
167 <= kVA < 250	2.5 – 8.0	500 <= kVA < 750	4.5 – 8.0
250 <= kVA < 667	3.5 – 8.0	750 <= kVA < 5000	5.0 – 8.0
667 <= kVA <= 833	5.0 – 8.0		

d. Tap Range of 20 Percent or More

Distribution transformers are commonly sold with voltage taps that allow manufacturers to adjust for minor differences in the input or output voltage. Transformers with multiple voltage taps, the highest of which equals at least 20 percent more than the lowest, computed based on the sum of the deviations of the voltages of these taps from the transformer's nominal voltage, are excluded from the definition of distribution transformers. 10 CFR 431.192. (*See also* 42 U.S.C. 6291(35)(B)(i))

In the response to the August 2021 Preliminary Analysis TSD, Schneider, NEMA, and Eaton recommended that only full-power taps should be permitted for tap range calculations. (Eaton, No. 55 at pp. 5–6; Schneider, No. 49 at pp. 5–6; NEMA, No. 50 at p. 4) Schneider and Eaton commented that the nominal voltage by which the tap range is calculated is a consumer choice and could result in two physically identical transformers being subject to standards or not, depending on the choice of nominal voltage. (Schneider No. 49 at p. 6; Eaton No. 55 at pp. 6–7)

In the January 2023 NOPR, DOE noted that, while traditional industry understanding of tap range is in percentages relative to the nominal voltage, stakeholder comments suggest that such a calculation can be applied such that two physically identical distribution transformers can be inside or outside of scope depending on the choice of nominal voltage. 88 FR 1722. To have a consistent standard for physically identical distribution transformers, DOE proposed to modify the calculation of tap range to only include full-power capacity taps and calculate tap range based on the transformer's maximum voltage rather than nominal voltage.

Prolec GE and NEMA commented that the proposed amendment to the calculation of a tap range of 20 percent or more was clear and removed ambiguity. (Prolec GE, No. 120 at p. 5; NEMA, No. 141 at p. 8) Howard and Eaton supported the proposed definition but recommended DOE make clarifying edits to avoid any confusion. (Howard, No. 116 at pp. 7–8; Eaton, No. 137 at p. 12)

Specifically, Eaton recommended changing DOE's proposal to use ''full-power voltage taps'' to read ''a transformer with multiple voltage taps, each capable of operating at full, rated capacity (kVA) . . .'' (Eaton, No. 137 at p. 12) Eaton commented that this clarification aligned with how full-power taps are more commonly described and clarified that full-capacity refers to kVA. *Id.*

Eaton and Howard also both noted that the description of how to calculate the tap range is confusing. Specifically, Eaton and Howard identified the text where DOE proposed to state ''the highest of which equals at least 20% more than the lowest, computed based on the sum of the deviations of these taps from the transformer's maximum full-power voltage.'' (Howard, No. 116 at pp. 7–8; Eaton, No. 137 at p. 12) Howard recommended DOE state ''where the difference between the highest tap voltage and the lowest tap voltage is 20 percent or more of the highest tap voltage.'' (Howard, No. 116 at pp.7–8) Eaton recommended DOE state ''whose range, defined as the maximum tap voltage minus minimum tap voltage, is 20 percent or more of the maximum tap voltage rating appearing on the product nameplate.'' (Eaton, No. 137 at p. 12)

Schneider commented that the proposed definition does clearly define how to calculate the tap percentage, but it does not address the fact that common LVDT products meet these criteria. (Schneider, No. 101 at p. 3) Schneider identified certain LVDT products designed to span multiple nominal voltages as having a tap-range greater than 20 percent. *Id.* Schneider recommended DOE modify the definition to allow for only one standard nominal voltage rating (*e.g.,* a transformer spanning 480V and 600V would not be exempted because it includes two standard voltage systems). *Id.*

Regarding Eaton's editorial suggestion as to how DOE specifies that only full-power taps are used, DOE agrees that Eaton's wording is clearer and better aligns with how industry addresses full-power taps. Therefore, DOE is adopting language that using full-power taps means ''each capable of operating at full, rated capacity (kVA)''.

Regarding Eaton and Howard's editorial suggestion as to how DOE communicates the calculation for the tap range, DOE notes that the proposed definition simply modified the current definition in the CFR to be based on the transformer's maximum full-power voltage, rather than the nominal voltage. However, DOE agrees that, with more explicit directions as to how to compute the tap range, the phrasing ''the highest of which equals at least 20 percent more than the lowest'' could be redundant and confusing. Therefore, DOE is simplifying the wording, in accordance with Howard and Eaton's suggestions to read that ''whose range, defined as the difference between the highest tap voltage and lowest tap voltage, is 20 percent or more of the highest tap voltage.''

Regarding Schneider's comment recommending that DOE only consider ''standard'' nominal voltage ratings to be eligible, DOE notes that the adopted test procedure for measuring the energy consumption of distribution transformers specifies how to handle reconfigurable nominal windings in the case of a dual- or multi-voltage capable transformers. (*See* appendix A to subpart K of 10 CFR part 431).

Transformer taps are intended to offer consumers the ability to conduct minor corrections to system voltage. The addition of voltage taps generally adds to a manufacturer's costs and reduces the efficiency of a product due to requiring additional winding material. Therefore, EPCA listed transformers with a tap range of 20 percent or more as excluded from the scope of the distribution transformer rulemaking. (*See* 42 U.S.C. 6291(35)(B)(i)) DOE's proposed amendment to the definition of a transformer with a tap range of 20 percent or more is only intended to clarify the provisions established under EPCA as to how this tap range is to be calculated across physically identical products. Transformers with tap ranges greater than 20 percent, are not within the scope of distribution transformers as defined in this final rule.

Based on the foregoing discussion, DOE is adopting a definition for transformer with a tap range of 20 percent or more to mean ''a transformer with multiple voltage taps, each capable of operating at full, rated capacity (kVA), whose range, defined as the difference between the highest voltage tap and the lowest voltage tap, is 20 percent or more of the highest voltage tap.''

e. Sealed and Non-Ventilated Transformers

The statutory definition of distribution transformer excludes transformers that are designed to be used in a special purpose application and are unlikely to be used in general purpose applications, such as ''sealed and non-ventilated transformers.'' (42 U.S.C. 6291(356)(b)(ii)) DOE defines sealed transformer and non-ventilated transformer at 10 CFR 431.192.

In the January 2023 NOPR, DOE proposed to modify the definitions of sealed and non-ventilated transformers to clarify that only certain ''dry-type'' transformers meet the definition of sealed and non-ventilated transformers. 88 FR 1722, 1744 DOE requested comment on this proposed amendment. *Id.*

Eaton and NEMA commented that the amendment provides clarity and agreed with including it in the definition. (Eaton, No. 137 at p. 13; NEMA, No. 141 at p. 8) DOE received no further comment on the proposed definition and is finalizing the clarification that sealed and non-ventilated transformers only include ''dry-type'' transformers.

Regarding the statutory exclusion of non-ventilated transformers broadly, Schneider commented that the original rationale for excluding non-ventilated transformers from EPCA was because non-ventilated transformers have higher core losses, which makes it difficult to meet efficiency standards at 35-percent loading, and because their inclusion would not drive significant energy savings. (Schneider, No. 101 at pp. 8–9) DOE notes that, because non-ventilated transformers do not have airflow or oil surrounding the core and coil, they have a harder time dissipating heat than general purpose dry-type distribution transformers. Transformer thermal limitations are governed by total losses at full load (*i.e.,* 100-percent PUL), where load losses make up a much higher percentage of total losses. As such, manufacturers of sealed and non-ventilated transformers typically increase no-load losses to decrease load losses, and therefore meet temperature rise limitations.

Schneider commented that while non-ventilated transformers are typically used in specialty applications,[41] there is

[41] Nonventilated transformers are typically marketed for specific hazardous environment

Continued

nothing inherent about non-ventilated transformers that would prevent them from being used in general purpose applications. (Schneider, No. 101 at pp. 8–9)

Schneider commented that non-ventilated transformers are typically larger and higher priced than general purpose LVDTs, which has historically discouraged consumers from using them in general purpose applications. (Schneider, No. 101 at p. 16) However, Schneider noted that if the proposed standards are adopted, specifically standards requiring amorphous cores, the increased volume and cost of general purpose LVDT units could become higher than non-ventilated units. *Id.* Schneider commented that if that were the case, manufacturers may choose to market non-ventilated transformer for general purpose applications to avoid the capital investment required to produce transformers with amorphous cores. *Id.* Schneider commented that if the proposed standards are finalized, it expects 50 percent of the LVDT market to purchase non-ventilated transformers instead of more efficient products. Schneider stated that because non-ventilated products are excluded from standards, the efficiency is likely to be very low, which would have a negative impact on any potential savings associated with LVDT transformers. *Id.* DOE notes that Schneider did not provide any specific data as to the relative increase in weight or production cost expected between non-ventilated transformers and general purpose distribution transformers to demonstrate how Schneider derived the 50 percent expected market share for non-ventilated transformers.

Schneider recommended that manufacturers work with Congress to modify the definition of low-voltage distribution transformer to remove the exclusion for non-ventilated transformers. (Schneider, No. 101 at p. 17)

DOE agrees that there are no technical features preventing a non-ventilated transformer from being used in general purpose applications. However, as described by Schneider, this substitution generally does not occur in industry because of the challenges associated with dissipating heat for non-ventilated transformers, which leads to non-ventilated transformers being larger and more expensive than a ventilated transformer of identical kVA. Further, dissipating heat becomes more of a challenge as the size of the transformer increases due to the significant amount of energy that larger transformers need to shed. As a result, the percentage increase in weight and cost of a non-ventilated transformer relative to a general purpose LVDT unit is greater for larger kVA transformers.

DOE reviewed manufacturer websites that listed product specifications and prices for both general purpose LVDTs and non-ventilated transformers (See Chapter 3 of the TSD). In general, DOE observed that the relatively higher cost and weight for non-ventilated transformers was considerably more than the modeled increase in cost and weight for even max-tech general purpose LVDTs. Therefore, non-ventilated distribution transformers are unlikely to become cost-competitive with more efficient, general purpose distribution transformers. Further, under the adopted standards, amorphous core transformers are not required for LVDTs. Therefore, it is unlikely for manufacturers to sell non-ventilated transformers into general purpose applications. As such, DOE maintains that non-ventilated transformers are statutorily excluded from the definition of distribution transformer on account of being used only in special purpose applications.

f. Step-Up Transformers

For transformers generally, the term ‘‘step-up’’ refers to the function of a transformer providing greater output voltage than input voltage. Step-up transformers primarily service energy producing applications, such as solar or wind electricity generation. In these applications, transformers accept an input source voltage, step-up the voltage in the transformer, and output higher voltages that feed into the electric grid. The definition of ‘‘distribution transformer’’ does not explicitly exclude transformers designed for step-up operation. However, most step-up transformers have an output voltage larger than the 600 V limit specified in the distribution transformer definition. *See* 10 CFR 431.192. (*See also* 42 U.S.C. 6291(35)(A)(ii))

In the January 2023 NOPR, DOE discussed how it is technically possible to operate a step-up transformer in a reverse manner, by connecting the high-voltage to the ‘‘output’’ winding of a step-up transformer and the low-voltage to the ‘‘input’’ winding of a step-up transformer, such that it functions as a distribution transformer. 88 FR 1722, 1744. However, DOE has also previously identified that this is not a widespread practice. 78 FR 2336, 23354. Comments received in response to the 2021 Preliminary Analysis TSD confirmed that, while step-up transformers are typically less efficient than DOE standards would mandate and step-up transformers could, in theory, be used in distribution applications, this is not a common practice. 88 FR 1722, 1744. Feedback from stakeholders indicated that step-up transformers typically serve a separate and unique application, often in the renewable energy field where transformer designs may not be optimized for the distribution market but rather are optimized for integration with other equipment, such as inverters. *Id.* As such, DOE did not propose to amend the definition of ‘‘distribution transformer’’ to account for step-up transformers. *Id.*

DOE received additional comments specifically regarding low-voltage step-up transformers in response to the January 2023 NOPR.

Schneider commented that there is confusion as to whether low-voltage step-up transformers are included in scope and recommended DOE explicitly state in the LVDT definition that both step-up and step-down transformers are within scope. (Schneider, No. 101 at p. 4) NEMA recommended clarifying that step-up LVDT transformers are within scope since both the input and output voltages meet the definition of distribution transformers. (NEMA, No. 141 at p. 9)

As previously noted, the definition of ‘‘distribution transformer’’ specifies that a transformer ‘‘has an output voltage of 600 V or less’’ and the definition of a low-voltage distribution transformer specifies ‘‘a distribution transformer that has an input voltage of 600 volts or less’’. *See* 10 CFR 431.192. Any step-up transformer with a primary input and output voltage less than our equal to 600 volts would therefore meet the definition of a low-voltage dry-type distribution transformer.

Any product meeting the definition of low-voltage dry-type distribution transformer, would be subject to DOE standards. DOE is not amending the definition of low-voltage dry-type distribution transformer to specifically include step-up transformers as this could be confusing to manufacturers of step-up transformers that do not meet the voltage limits (and therefore are not within the scope of distribution transformer efficiency standards). Further, as described in the foregoing discussion, these low-voltage dry-type products are already included within the definition of low-voltage dry-type distribution transformer.

applications where airborne contaminants or large quantities of particles would potentially harm the performance of a traditional ventilated distribution transformer.

g. Uninterruptible Power Supply Transformers

''Uninterruptible power supply transformer'' is defined as a transformer that is used within an uninterruptible power system, which in turn supplies power to loads that are sensitive to power failure, power sags, over voltage, switching transients, line noise, and other power quality factors. 10 CFR 431.192. An uninterruptible power supply transformer is excluded from the definition of distribution transformer. 42 U.S.C. 6291(35)(B)(ii); 10 CFR 431.192. Such a system does not step-down voltage, but rather it is a component of a power conditioning device, and it is used as part of the electric supply system for sensitive equipment that cannot tolerate system interruptions or distortions to counteract such irregularities. 69 FR 45376, 45383. DOE has clarified that uninterruptible power supply transformers do not ''supply power to'' an uninterruptible power system; rather, they are ''used within'' the uninterruptible power system. 72 FR 58190, 58204. This clarification is consistent with the reference in the definition to transformers that are ''within'' the uninterruptible power system. 10 CFR 431.192.

In the January 2023 NOPR, DOE noted that transformers at the input, output or bypass that are supplying power to an uninterruptible power system are not uninterruptible power supply transformers. 88 FR 1722, 1745. Accordingly, DOE proposed to amend the definition of ''uninterruptible power supply transformer'' to explicitly state that transformers at the input, output, or bypass of a distribution transformer are not a part of the uninterruptible power system and requested comment on the proposed amendment. *Id.*

In response, NEMA recommended that DOE include in the definition of an uninterruptible power supply transformer that these transformers must include a core with an air gap and/or a shunt core. NEMA stated these features prevent uninterruptible power supply transformers from meeting the proposed efficiency standards and transformers that do not include at least one of these attributes would not meet the definition of an uninterruptible power supply transformer. (NEMA, No. 141 at p. 8) Prolec GE commented that the proposed amendment to the definition provides helpful clarification, but suggested DOE confirm its usage of the terms ''uninterruptable'' and ''uninterruptible''. (Prolec GE, No. 120 at p. 5)

DOE notes that its usage of ''uninterruptable'' in the January 2023 NOPR was an inadvertent typographical error. In this final rule, all instances of ''uninterruptable'' have been corrected to ''uninterruptible.''

Regarding NEMA's recommendation to include a requirement for a core with an air gap and/or a shunt core, DOE reviewed available literature to evaluate the relevance of these design features, specifically regarding how prevalent they are in the design of uninterruptible power supply transformers and how they may impact the efficiency of a distribution transformer. Based on its review, DOE interprets the terms ''magnetic shunt'' and ''air gap'' as they appear in NEMA's comment to refer to the definitions prescribed in in IEEE Standard 449–1998 (R2007) ''IEEE Standard for Ferroresonant Voltage Regulators'' (''IEEE 449'').[42] IEEE 449 defines a magnetic shunt as ''the section of the core of the ferroresonant transformer that provides the major path for flux generated by the primary winding current that does not link the secondary winding''; IEEE 449 defines an air gap as ''the space between the magnetic shunt and the core, used to establish the required reluctance of the shunt flux path.'' DOE understands these features to provide a high reluctance pathway for excess magnetic flux such that the secondary voltage will remain constant, even when the primary side voltage fluctuates unexpectedly. This functionality would be particularly useful in uninterruptible power supply transformers, which provide a smooth and continuous supply of electricity to avoid damaging any downstream equipment.

However, DOE notes that the definitions of ''air gap'' and ''magnetic shunt'' as they are presented in IEEE 449 do not appear to be the only examples of these features as they appear in transformer design. For example, stacked core designs have inherent air gaps that do not provide the same high reluctance pathway for magnetic flux. Additionally, DOE observed transformer designs advertised as having ''magnetic shunts,'' consisting of laminated steel sheets installed on or surrounding the transformer core to prevent leakage flux from affecting the transformer tank or other surrounding components. These alternative applications for these features could create confusion as to which transformers would meet the definition of an uninterruptible power supply transformer.

While inclusion of either an ''air gap'' or ''shunt core'' may be useful features in identifying uninterruptible power supply transformers, DOE lacks sufficient data to properly characterize these attributes. DOE also has not received sufficient feedback from stakeholders to indicate that these features are exclusive to uninterruptible power supply transformers or if they would encompass many other transformers not intended to be uninterruptible power supply transformers. Further, NEMA has previously commented that manufacturers are applying the definition of uninterruptible power supply transformer appropriately and clarification is not needed. (NEMA, No. 50 at p. 4)

DOE notes that the proposed definition only sought to codify DOE's existing interpretation that uninterruptible power supply transformers must be ''within'' an uninterruptible power system and not at the ''input, output, or bypass'' of an uninterruptible power system. Therefore, in this final rule, DOE is finalizing the proposed definition of ''uninterruptible power supply transformer.''

h. Voltage Specification

As stated, the definition of ''distribution transformer'' is based, in part, on the voltage capacity of equipment, *i.e.,* has an input voltage of 34.5 kV or less, and has an output voltage of 600 V or less. 10 CFR 431.192. (42 U.S.C. 6291(35)(A)) Three-phase distribution transformer voltage may be described as either ''line,'' *i.e.,* measured across two lines, or ''phase,'' *i.e.,* measured across one line and the neutral conductor. For delta-connected[43] distribution transformers, line and phase voltages are equal. For wye-connected distribution transformers, line voltage is equal to phase voltage multiplied by the square root of three.

DOE notes that it previously stated that the definition of distribution transformer applies to ''transformers having an output voltage of 600 volts or less, not having only an output voltage of less than 600 volts.''[44] 78 FR 23336, 23353. For example, a three-phase wye-connected transformer for which the output phase voltage is at or below 600 V, but the output line voltage is above

[42] IEEE SA. (1998). IEEE 449–1998—IEEE Standard for Ferroresonant Voltage Regulators (Accessed on 09/15/2023). Available online at: *standards.ieee.org/ieee/449/675/.*

[43] Delta connection refers to three distribution transformer terminals, each one connected to two power phases.

[44] Inclusive of a transformer at 600 volts.

600 V would satisfy the output criteria of the distribution transformer definition. DOE's test procedure requires that the measured efficiency for the purpose of determining compliance be based on testing in the configuration that produces the greatest losses, regardless of whether that configuration alone would have placed the transformer at-large within the scope of coverage. *Id.* Similarly, with input voltages, a transformer is subject to standards if either the ''line'' or ''phase'' voltages fall within the voltage limits in the definition of distribution transformers, so long as the other requirements of the definition are also met. *Id*

In response to the August 2021 Preliminary Analysis TSD, DOE received feedback that it should clarify the interpretation of voltage in the regulatory text. (Schneider, No. 49 at p. 8; NEMA, No. 50 at p. 4; Eaton, No. 55 at pp. 7–8). In the January 2023 NOPR, DOE noted that the voltage limits in the definition of distribution transformer established in EPCA do not specify whether line or phase voltage is to be used. 88 FR 1722, 1745; 42 U.S.C. 6291(35). However, DOE also discussed that, upon further evaluation, the distribution transformer input voltage limitation aligns with the common maximum distribution circuit voltage of 34.5 kV.[45] [46] This common distribution voltage aligns with the distribution line voltage, implying that the intended definition of distribution transformer in EPCA was to specify the input and output voltages based on the line voltage. Accordingly, DOE tentatively determined that applying the phase voltage, as DOE cited in the April 2013 Standards Final Rule, would cover products not traditionally understood to be distribution transformers and not intended to be within the scope of distribution transformer as defined by EPCA. 88 FR 1722, 1745. DOE also noted in the January 2023 NOPR that the common distribution transformer voltages have both line and phase voltages that are within DOE's scope, and therefore the proposed change is not expected to impact the scope of this rulemaking aside from select, unique transformers with uncommon voltages. *Id.* Accordingly, DOE proposed to modify the definition of distribution transformer to state explicitly that the input and output voltage limits are based on the ''line'' voltage and not the phase voltage.

In response, Eaton commented that DOE's revised interpretation of input and output voltages better aligns with industry. (Eaton, No. 137 at p. 13). NEMA commented that the addition of line voltage removes ambiguity and clearly defines products that need to be in compliance. (NEMA, No. 141 at p. 9). NEMA further recommended that the LVDT definition should also be updated to clarify that the voltage specifications are line voltages. (NEMA, No. 141 at p. 8) Schneider also supported DOE's clarification that input and output voltages are line voltages and recommended adding a similar clarification to the LVDT definition. (Schneider, No. 101 at p. 4)

Howard commented that clarifying that voltage refers to line voltage is an improvement to the definition of input and output voltage. However, Howard further stated that it is more common in industry to refer to line voltage as the ''nominal system'' voltage. Howard recommended that rather than using ''line'' voltages, DOE should use ''nominal system voltage,'' which is used in many industry standards, and proposed defining ''nominal system voltage.'' Howard additionally supported DOE's assessment that the revised definitions of input and output voltage would only impact products not considered by industry to be serving distribution applications. (Howard, No. 116 at p. 8–9)

DOE reviewed relevant industry standards to assess Howard's recommendation. Based on this review, DOE found that, while the term ''nominal system voltage'' has been adopted in several standards, its usage is not ubiquitous. For example, IEEE standard C57.91–2020 interchangeably uses the terms ''nominal voltage,'' ''line voltage,'' and ''line-to-line voltage'' to specify transformer voltage ratings.[47] Other standards similarly specify voltage ratings using the terms ''phase-to-phase,'' ''line-to-ground nominal system voltage,'' or ''nominal line-to-line system voltage.'' Further, DOE reviewed manufacturer catalogs for distribution transformers and observed that it is more common to specify transformer voltage ratings according to the ''line voltage,'' as opposed to the ''nominal system voltage.'' The comments received from Eaton and NEMA additionally indicate that the term ''line voltage'' is well understood in industry and sufficiently clarifies the definitions of input and output voltage.

Therefore, for the reasons discussed, DOE is modifying the definition of distribution transformer in this final rule to state explicitly that the input and output voltage limits are based on the ''line'' voltage and not the phase voltage. Similarly, in accordance with the feedback submitted by NEMA and Schneider, DOE is similarly amending the definition of ''low-voltage dry-type distribution transformer'' to state a transformer that has ''an input line voltage of 600 volts or less''.

i. kVA Range

The EPCA definition for distribution transformers does not include any capacity range. In codifying the current distribution transformer capacity ranges in 10 CFR 431.192, (10 kVA to 2500 kVA for liquid-immersed units and 15 kVA to 2500 kVA for dry-type units), DOE noted that distribution transformers outside of these ranges are not typically used for electricity distribution. 71 FR 24972, 24975–24976. Further, DOE noted that transformer capacity is to some extent tied to its primary and secondary voltages, meaning that the EPCA definition has the practical effect of limiting the maximum capacity of transformers that meet those voltage limitations to approximately 3,750 to 5,000 kVA, or possibly slightly higher. *Id.* DOE established the current kVA range for distribution transformers by aligning with NEMA publications in place at the time that DOE adopted the range, specifically the NEMA TP–1 standard. 78 FR 23336, 23352. DOE cited these documents as evidence that its kVA scope is consistent with industry understanding (*i.e.,* NEMA TP–1 and NEMA TP–2), but noted that it may revise its understanding in the future as the market evolves. 78 FR 2336, 23352.

In the January 2023 NOPR, DOE noted that several industry sources suggest that the distribution transformer kVA range may exceed 2,500 kVA. 88 FR 1722, 1746. Specifically, DOE cited Natural Resources Canada (NRCAN) regulations that include dry-type distribution transformers up to 7,500 kVA.[48] The European Union (EU) Ecodesign requirements also specify maximum load losses and maximum no-load losses for three-phase liquid-

[45] Pacific Northwest National Lab and U.S. Department of Energy (2016), ''Electricity Distribution System Baseline Report.'', p. 27. Available at *www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf.*

[46] U.S. Department of Energy (2015), ''United States Electricity Industry Primer.'' Available at *www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf.*

[47] IEEE SA. (2020). IEEE C57.12.91–2020—IEEE Standard Test Code for Dry-Type Distribution and Power Transformers. Available at *standards.ieee.org/standard/C57_12_91-2020.html* (last accessed June 21, 2023).

[48] See NRCAN dry-type transformer energy efficiency regulations at *www.nrcan.gc.ca/energyefficiency/energy-efficiency-regulations/guidecanadas-energy-efficiency-regulations/dry-typetransformers/6875.*

immersed distribution transformers up to 3,150 kVA.[49]

DOE noted that manufacturers in interviews had stated that transformers beyond 2,500 kVA are typically step-up transformers serving renewable applications, which would be outside the scope of standards on account of exceeding the output voltage limit. 88 FR 1722, 1746. However, DOE cited comments by NEMA and Eaton, which suggested that some number of general purpose distribution transformers are sold beyond 2,500 kVA. (NEMA, No. 50 at p. 5; Eaton, No. 55 at p. 8). Further, DOE noted that some manufacturers expressed concern in interviews that in the presence of amended energy conservation standards, there may be increased incentive to build distribution transformers that are just above the existing scope (*e.g.,* 2,501 kVA). 88 FR 1722, 1746.

In response to this feedback, DOE proposed to expand the scope of the definition of distribution transformer to 5,000 kVA. DOE requested comment as to whether 5,000 kVA represented the upper limit for distribution transformers. *Id.* at 88 FR 1747.

DOE also estimated energy savings for transformers greater than 2,500 kVA but less than or equal to 5,000 kVA by scaling certain representative units. In estimating energy savings, DOE assumed these units are purchased based on lowest first cost and use similar grades of electrical steel as in-scope units but are not required to meet any efficiency standards. DOE requested comment on the number of shipments and distribution of efficiency for these large three-phase distribution transformers. *Id.*

NAHB submitted data showing that imports for liquid-immersed transformers with ratings above 2500 kVA have increased significantly in the past decade and expressed concern that the proposed standards would negatively impact the import market for these products. (NAHB, No. 106 at pp. 8–9) DOE notes that the data cited by NAHB is for all transformers greater than 2,500 kVA without considering their secondary voltage. Most transformers greater than 2,500 kVA would be substation or large power transformers with output voltages that vastly exceed 600V. Due to the voltage limitations, virtually all transformers cited by NAHB would not be subject to DOE efficiency regulations regardless of the kVA range for the definition of distribution transformer.

Howard commented that transformers beyond 2,500 kVA are not within the technical scope of what is considered a distribution transformer and should not be a part of distribution transformer regulations. (Howard, No. 116 at pp. 9, 19) Howard stated that they produce a very small number of 3,000, 3,750, and 5,000 kVA transformers per year that are primarily used for unique and specialized applications, not as a means to circumvent DOE regulations. *Id.* Howard referred DOE to IEEE C57.12.34 and C57.12.36 industry standards, which Howard stated do not specify an impedance value for 5,000 kVA transformers with a low-voltage rating of 600 V and below.[50] *Id.* Prolec GE commented that transformers between 2,500 kVA and 5,000 kVA may maintain certain characteristics as distribution transformers but are mainly specified and purchased by industrial customers and not intended for general purpose applications. (Prolec GE, No. 120 at p. 5)

Eaton commented that between 2016 and 2022, it built zero transformers above a kVA rating of 5,000 kVA that also had an output voltage of 600 V or less. (Eaton, No. 137 at p. 13) Howard commented that units above 2,500 kVA with secondary voltages of 600 V or less represent less than one percent of Howard's annual three-phase pad mounted transformer shipments. (Howard, No. 116 at p. 10) Howard stated that units over 2,500 kVA have very few shipments, representing a very small number of specialized units. (Howard, No. 116 a p. 19)

Howard stated that the average efficiency of these units is 99.4 percent and achieving lower losses than this becomes difficult due to the very high currents that lead to significant stray and eddy losses. (Howard, No. 116 at p. 10) Howard stated that if DOE elects to include these high-kVA units, their efficiencies should not be on-par with smaller units due to the unique challenges associated with high-kVA units. (Howard, No. 116 at p. 19)

Eaton commented that because the scaling relationships do not hold with high-kVA units, DOE should work with manufacturers to identify more accurate max-tech efficiency levels for high-kVA transformers. (Eaton, No. 137 at p. 28) Eaton provided data showing what their design software calculated as max-tech for 3-phase distribution transformers at various voltages across a range of kVA values. (Eaton, No. 137 at p. 28)

Prolec GE commented that the proposed standards for transformers above 2,500 kVA result in a much larger increase in standards than all other transformers because they are not currently subject to efficiency standards and therefore the baseline transformer is less efficient than transformers that are in-scope today. (Prolec GE, No. 120 at p. 12)

Hammond commented that the 5,000 kVA limit is preferrable for medium-voltage dry-type distribution transformer units; however, the high-currents of these designs may make efficiency standards infeasible and, therefore, it may be necessary to apply an exclusion for high-current units, similar to the NRCAN regulations. (Hammond, No. 142 at p. 3)

In reviewing the technical challenges associated with meeting energy conservation standards for large three-phase units, DOE agrees that the presence of both very high kVA ratings and an output voltage of 600V could lead to very high currents that would inherently lead to manufacturing challenges, making it more costly to meet a given efficiency standard. However, DOE notes that industry standards recommend minimum low-voltage ratings that vary based on kVA.[51] As a result, larger kVA transformer tend to have higher secondary voltages. While maintaining these recommended voltage ratings does not entirely eliminate the challenges faced by high-current transformers, as further discussed in section IV.A.2.c, it generally helps maintain a reasonable current.

DOE notes that one of the primary reasons it cited for proposing to include higher kVA distribution transformer within the scope of the distribution transformer rulemaking was concern from manufacturers that, in the presence of amended energy conservation standards, there may be increased incentive to build distribution transformers that are just above the existing scope (*e.g.,* 2,501 kVA). 88 FR 1722, 1746.

NEMA commented in response to the January 2023 NOPR that some customers have requested units just beyond the scope of regulations (*e.g.* 2,501 kVA). (NEMA, No. 141 at p. 9) The Efficiency Advocates commented that they support DOE's proposal to include capacities up to 5,000 KVA based on manufacturer comment that some products are sold here that meet the voltage limits and to eliminate the potential incentive to build transformers just beyond the current scope in the

[49] Official Journal of the European Union, Commission Regulation (EU) No. 548/2014, May 21, 2014, Available at *eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2014.152.01.0001.01.ENG.*

[50] See Table 2 of IEEE Std C57.12.34–2022 and Table 5 of IEEE Std C57.12.36–2017.

[51] See Table 3 of IEEE Std C57.12.36–2017.

presence of amended standards. (Efficiency Advocates, No. 121 at p.7)

Stakeholder comments indicate that losses for high-kVA transformers increase at a faster rate than modeled by the scaling relationships used in the January 2023 NOPR, causing the proposed standards for these high-kVA units to be beyond what is technologically feasible. Based on the feedback received, DOE conducted additional investigation into the interaction between capacity, current, and efficiency standards, as discussed in sections IV.A.2.c and IV.C.1.e. Based on the feedback received from manufacturers and this additional technical investigation, DOE has determined that the primary challenge associated with meeting efficiency standards for higher kVA distribution transformers is related to the high-current associated with those transformers.

If built per the minimum voltage recommendations of IEEE Std C57.12.36–2017, 5,000 kVA transformers would never have an output voltage less than or equal to 600V, and 3,750 kVA transformers would also typically be larger than 600V. This indicates that 3,750 kVA or 5,000 kVA transformers would likely not have output voltages that meet the definition of distribution transformers subject to energy conservation standards, if built per industry standards.

However, stakeholder comments also suggest that consumers have requested transformers just beyond 2,500 kVA (*i.e.,* 2,501 kVA), that are not built per industry standard kVA ranges to use in general purpose applications, which could increase in the presence of amended efficiency standards. As such, DOE is finalizing an expansion to include distribution transformers less than or equal to 5,000 kVA, as proposed in the January 2023 NOPR. However, DOE requested comment on its modeling of high-kVA units (88 FR 1722, 1760) and based on stakeholder feedback has modified its modeling (as discussed in section IV.C.1.e) and adopted efficiency levels for these high-kVA units to reflect the challenges associated with high-currents in distribution transformers.

DOE notes that this finalized definition reduces the risk of non-standard kVA transformers being built just beyond the scope of regulations in an effort to circumvent efficiency requirements, while accommodating the legitimate challenges associated with high-current transformers. DOE discusses the specific comments related to high-current transformers in section IV.A.2.c of this document.

2. Equipment Classes

When evaluating and establishing or amending energy conservation standards, DOE may establish separate standards for a group of covered equipment (*i.e.,* establish a separate equipment class) if DOE determines that separate standards are justified based on the type of energy used, or if DOE determines that a product's capacity or other performance-related feature justifies a different standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)) In making a determination whether a performance-related feature justifies a different standard, DOE considers such factors as the utility of the feature to the consumer and other factors DOE determines are appropriate. (*Id.*)

Eleven equipment classes are established under the existing standards for distribution transformers, one of which (mining transformers[52]) is not subject to energy conservation standards. 10 CFR 431.196. The remaining ten equipment classes are delineated according to the following characteristics: (1) type of transformer insulation: liquid-immersed or dry-type, (2) number of phases: single or three, (3) voltage class: low or medium (for dry-type only), and (4) basic impulse insulation level (BIL) (for MVDT only).

Table IV.3 presents the eleven equipment classes that exist in the current energy conservation standards and provides the kVA range associated with each.

Table IV.3 Current Equipment Classes for Distribution Transformers

EC* #	Insulation	Voltage	Phase	BIL Rating	kVA Range
EC1	Liquid-Immersed	Medium	Single	-	10-833 kVA
EC2	Liquid-Immersed	Medium	Three	-	15-2500 kVA
EC3	Dry-Type	Low	Single	-	15-333 kVA
EC4	Dry-Type	Low	Three	-	15-1000 kVA
EC5	Dry-Type	Medium	Single	20-45kV BIL	15-833 kVA
EC6	Dry-Type	Medium	Three	20-45kV BIL	15-2500 kVA
EC7	Dry-Type	Medium	Single	46-95kV BIL	15-833 kVA
EC8	Dry-Type	Medium	Three	46-95kV BIL	15-2500 kVA
EC9	Dry-Type	Medium	Single	≥ 96kV BIL	75-833 kVA
EC10	Dry-Type	Medium	Three	≥ 96kV BIL	225-2500 kVA
EC11	Mining Transformers				

* EC = Equipment Class

DOE notes that across the existing transformer equipment classes, numerous factors can impact the cost and efficiency of a distribution transformer. Certain factors like primary voltage, secondary voltage, insulation material, specific impedance designs, voltage taps, *etc.,* can all increase the price of a given transformer and lead to an increase in transformer losses, which may make meeting any given efficiency standard more difficult. Distribution transformers are frequently customized by consumers to add features, safety margins, *etc.* However, DOE has

[52] A mining distribution transformer is 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 identified the transformer as being for this use only. 10 CFR 431.192.

determined that in general these differences are not sufficient to warrant separate equipment classes. Having a different equipment class for all possible kVA and voltage combinations is infeasible, would add complexity to optimization software, and was not suggested by any stakeholders. Within a given equipment class and efficiency standard, there is typically sufficient ''margin'' such that all small variabilities in design can meet efficiency standards without reaching an ''efficiency wall'' wherein any additional efficiency gains become substantially more expensive. However, certain design variabilities may warrant separation into additional equipment classes such that the product features remain on the market. In the January 2023 NOPR, DOE requested comment and data on a variety of other potential equipment features that may warrant a separate equipment class. 88 FR 1722, 1747. These comments are discussed in detail below.

a. Submersible Transformers

Certain distribution transformers are installed underground and, accordingly, may endure partial or total immersion in water. In the January 2023 NOPR, DOE stated that the subterranean installation of submersible distribution transformers means that there is less circulation of ambient air for shedding heat. 88 FR 1722, 1748. Operation while submerged in water and in contact with run-off debris further impacts the ability of a distribution transformer to transfer heat to the environment and limits the alternative approaches in the external environment that can be used to increase cooling (*e.g.,* adding radiators).

DOE noted that distribution transformer temperature rise tends to be governed by load losses and that it is typical for design options that reduce load losses to increase no-load losses. 88 FR 1722, 1748. While no-load losses make up a relatively small portion of losses at full load, no-load losses can contribute a significant portion of total losses at 50-percent PUL, at which manufacturers must certify efficiency. However, due to the potentially reduced heat transfer of a subterranean environment, combined with the possibility of operating while submerged, customers must reduce load losses to meet temperature rise limitations. Therefore, the design choices needed to meet a lower temperature rise may lead manufacturers to increase no-load losses and may make it more difficult to meet a given efficiency standard at 50-percent PUL.

In the January 2023 NOPR, DOE tentatively determined that distribution transformers designed to operate while submerged and in contact with run-off debris constitutes a performance-related feature which other types of distribution transformers do not have. 88 FR 1722, 1748. At max-tech efficiency levels, both no-load and load losses are low enough that distribution transformers generally do not meet their rated temperature rise. However, at intermediate efficiency levels, trading load losses for no-load losses allows distribution transformers to be rated for a lower temperature rise. This may make it more difficult to meet any amended efficiency standard, as no-load losses contribute proportionally more to efficiency at the test procedure PUL as compared to at the rated temperature rise. *Id.*

In defining a submersible distribution transformer, DOE noted that the IEEE C57.12.80–2010 includes numerous definitions for transformers designed to operate in partial or total submersion. *Id.* DOE attempted to identify the physical features that would distinguish transformers capable of operating in a submersible operation by reviewing industry standards IEEE C57.12.23–2018 and IEEE C57.12.24–2016. *Id.* DOE proposed to define a submersible distribution transformer as ''a liquid-immersed distribution transformer so constructed as to be successfully operable when submerged in water including the following features: (1) is rated for a temperature rise of 55 °C; (2) has insulation rated for a temperature rise of 65 °C; (3) has sealed-tank construction; and (4) has the tank, cover, and all external appurtenances made of corrosion-resistant material.'' *Id.* DOE noted that this definition sought to incorporate the physical features associated with submersible transformers that are included in industry standards. DOE requested comment on its definition of submersible distribution transformer and information regarding the specific design characteristics that limit efficiency. *Id.*

APPA supported creating a separate equipment class for vault, submersible, or special installation transformers and supported DOE's proposal not to establish higher efficiency standards for those units. (APPA, No. 103 at p. 3)

Howard supported a separate equipment class for submersible distribution transformers because of their lack of cooling, higher ambient temperatures, and higher installation costs. (Howard, No. 116 at p. 11) Howard commented that comparing its submersible transformers to its non-submersible transformers requires a 10- to 12-percent increase in no-load losses and comparable reduction in load losses to meet maximum temperature rise characteristics. (Howard, No. 116 at p. 11) Howard added that in addition to the reduced cooling, submersible transformers also frequently have bushings, switches, tap changers, and other accessories mounted on the cover, which increases lead lengths and therefore increases losses. (Howard, No. 116 at p. 11)

Prolec GE and NEMA commented that submersible transformers are limited in their ability to meet higher efficiency levels on account of needing to meet the strict dimensional requirements associated with fitting in existing vaults, their limited heat transformer on account of needing to operate in dirty water, and their need to have corrosion-resistant construction, which is thicker and reduces the transformer's ability to remove heat. (NEMA, No. 141 at p. 10; Prolec GE, No. 120 at p. 9) Due to these limitations, Prolec GE supported DOE establishing a separate equipment class for submersible transformers and not increasing efficiency standards. (Prolec GE, No. 120 at p. 9) Carte supported establishing a separate equipment class for submersible transformers and not establishing higher efficiency levels because of the strict dimensional constraints associated with installations in vault locations. (Carte, No. 140 at p. 7)

WEC commented that DOE's proposed equipment class and no-new-standard determination for submersible distribution transformers would not cover WEC's more cost effective approach of using pad mounted transformers in certain vault applications. (WEC, No. 118 at p. 2) DOE notes that in cases where utilities are using traditional pad-mounted distribution transformers in vault applications, there are not going to be the same thermal limitations that represent the technical features identified by stakeholders as warranting a separate equipment class.

Regarding DOE's proposed definition of submersible distribution transformer, Carte commented that some utilities in unique locations use a 65 °C temperature rise in their transformer vaults. (Carte, No. 140 at p. 7) Prolec GE and NEMA commented that submersible distribution transformer is already defined per IEEE standards C57.12.24 and C57.12.40. (Prolec GE, No. 120 at p. 6; NEMA, No. 141 at pp. 9–10) Prolec GE and NEMA further commented that the unique design and characteristics of submersible transformers makes them rarely compatible with above ground installation. (Prolec GE, No. 120 at p. 6; NEMA, No. 141 at pp. 9–10) Prolec GE and NEMA commented that IEEE C57.12.80 identifies installation in a vault as a common characteristic for submersible, subway, and network transformers. (Prolec GE, No. 120 at p. 6; NEMA, No. 141 at pp. 9–10)

Howard commented that DOE should align the definition with IEEE standards C57.12.23, C57.12.24, and C57.12.40. Howard added that if DOE elects not to align with IEEE standards, DOE should modify feature (4) of the definition to clarify that copper-bearing steel with minimum specified thicknesses for tanks, covers, and auxiliary coolers is an acceptable alternative to stainless steel as a ''corrosion-resistant material.'' (Howard, No. 116 at p. 10) Prolec GE and NEMA recommended submersible distribution transformer be defined as ''a liquid-immersed distribution transformer, so constructed as to be operable when fully submerged in water including the following feature: (1) has sealed tank construction; (2) has the tank, cover and all external appurtenances made of corrosion-resistance material or with appropriate corrosion-resistance surface treatment to induce the components surface to be corrosion resistant; and (3) is designed for installation in an underground vault.'' (Prolec GE, No. 120 at p. 6; NEMA, No. 141 at pp. 9–10)

In reviewing the nuances NEMA, Prolec GE, and Howard described as to the different approaches manufacturers may take to ensure their distribution transformer is constructed to operate when submerged in water, DOE agrees that different insulating fluids may modify the exact temperature rise of a given submersible distribution transformer and the primary physical features associated with submersible transformers include having sealed tank construction and corrosion resistant surroundings. As noted, DOE described the physical features identified in the NOPR based on a review of these industry standards and intended to align its definition with the physical features identified in these standards.

Therefore, DOE is adopting a definition for submersible distribution transformer to mean ''a liquid-immersed distribution transformer, so constructed as to be operable when fully or partially submerged in water including the following features: (1) has sealed-tank construction; and (2) has the tank, cover, and all external appurtenances made of corrosion-resistant material or with appropriate corrosion resistant surface treatment to induce the components surface to be corrosion resistant.''

b. Large Single-Phase Transformers

DOE received several comments from stakeholders (discussed in sections IV.C.1.d and IV.E.2 of this document) noting that in the immediate future, the ability to operate transformers efficiently at higher loading may represent a distinct consumer utility. (APPA, No. 103 at p. 17; NEPPA, No. 129 at p. 2; Cliffs, No. 105 at pp. 16–17; Carte, No. 140 at p. 6) Specifically, an increased ability to overload small single-phase transformers, which are often placed most directly near consumer loads, provides safety and reliability amidst uncertainty over near-future demand patterns as electrification proceeds. DOE notes that the ability to overload a distribution transformer is related to a transformer's temperature rise and insulation.

The likelihood of a distribution transformer being overloaded is a function of, among other factors, the size of the transformer and the number of consumers being served by a given distribution transformer. While smaller kVA transformers tend to serve a smaller number of households, the loading on those smaller transformers could vary with considerably more irregularity because the actions of a small number of individuals can drastically impact loading. Larger kVA transformers tend to serve a larger number of households, with overall loading on the transformer distributed across a larger number of individuals. Therefore, while loading still varies, it varies more predictably as no single individual can impact the loading on a single transformer as significantly. As a result, larger kVA transformers are less likely to be subject to overloading conditions than their smaller kVA counterparts.

Instantaneous temperature rise on a transformer tends to be governed by load losses and it is typical for design options that reduce load losses to increase no-load losses. While no-load losses typically make up a relatively small portion of losses at full load, no-load losses can contribute a significant portion of total losses at 50-percent PUL, at which manufacturers must currently demonstrate compliance with energy conservation standards at 10 CFR 431.196(b). The design choices needed to reduce temperature rise may lead manufacturers to increase no-load losses, as not doing so may increase the cost of the distribution transformer and diminish sales in a market sensitive to selling price. Further, because operating temperature is impacted by the ability of the transformer to dissipate heat, a transformer's tolerance of overloading is directly linked to its ability to shed heat. Heat transfer is directly dependent on the ratio of distribution transformer surface area to volume. In other words, the more surface area that a transformer has per unit of volume, the more effectively it will be able to shed heat. As transformer capacity increases, however, the weight and volume of the transformer tend to increase more rapidly than the surface area, meaning that heat transfer become less effective. As a result, smaller kVA transformers tend to be more physically suitable for sustaining overload conditions than larger kVA transformers, which typically need additional radiators to effectively remove heat.

Similarly to submersible transformers, at the max-tech efficiency levels for single phase transformers, both the no-load and load losses are low enough that distribution transformers generally do not meet their rated temperature rise. However, at intermediate efficiency levels, trading load losses for no-load losses may allow smaller distribution transformers serving fewer consumers to have increased overload capability, particularly if paired with less-flammable insulating liquid. This combination may make it more difficult to meet any amended efficiency standard, as no-load losses contribute proportionally more to efficiency at the test procedure PUL as compared to at the rated temperature rise. *Id.*

One utility investigated the likelihood of distribution transformers being overloaded based on potential electric vehicle (EV) charging penetration rates for single-phase transformers ranging from 15 to 100 kVA. This study found that smaller transformers have a high likelihood of being overloaded and, as the size of those transformers increases, the percentage of overloaded transformers at a given kVA goes to zero beyond 100 kVA.[53] While in the longer term, the study recommends upsizing transformers such that loading on transformers remains low, in the immediate future, consumers will value increased overload capacity as a consumer feature for small, single-phase transformers.

Based on this data, for this final rule DOE has evaluated two equipment classes for single-phase liquid-immersed distribution transformers. Equipment Class 1A corresponds to single-phase

[53] Dalah, S., Aswani, D., Geraghty, M., Dunckley, J., *Impact of Increasing Replacement Transformer Size on the Probability of Transformer Overloads with Increasing EV Adoption,* 36th International Electric Vehicle Symposium and Exhibition, June, 2023. Available online at: *https://evs36.com/wp-content/uploads/finalpapers/FinalPaper_Dahal_Sachindra.pdf.*

liquid-immersed distribution transformers greater than 100 kVA. Equipment Class 1B corresponds to single-phase liquid-immersed distribution transformers ranging from 10–100 kVA. Equipment Class 1A includes units that are unlikely to be overloaded, while Equipment Class 1B includes units that are at higher likelihood of being overloaded and, therefore, consumers are more likely to exchange no-load losses for load losses, thereby making it more difficult to meet amended efficiency standards.

DOE notes that in the cited study exploring the likelihood of overloading in the presence of high-EV penetration (corresponding to a 50% penetration rate by 2035), the overloading likelihood ranges from 100 percent for 15 kVA transformers to 2.5 percent for 100 kVA transformers. However, when those 100 kVA transformers are upsized, the overload likelihood in the high-EV penetration scenario falls to 0.1 percent, indicating that 100 kVA approximately corresponds to the upper limit of single-phase transformers that are likely to experience overloading and therefore likely to be designed to trade load losses for no-load losses to reduce the loss-of-life impacts associated with overloading. DOE considered other potential capacities for separating equipment, as lower-EV penetration scenarios show that 75 kVA and 100 kVA transformers are unlikely to be overloaded. However, given the regional variance of EV penetration, DOE has determined that even in the most aggressive EV-penetration scenarios, the likelihood of overloading falls to virtually zero above 100 kVA. Therefore, in light of the above, DOE has determined that 10–100 kVA and above 100 kVA are reasonable capacity designation for determining product classes.

As noted, higher efficiency levels can result in low no-load and load losses; however, intermediate efficiency levels require trading off between the two. Further, the utility associated with increased overloading is likely limited to the near-term electrification build-out, wherein a significant number of new loads, notably electric vehicles, are being added to the grid. Longer-term, utilities are expected to replace this overloading ability with larger kVA transformers, as recommended by the aforementioned study.

While DOE did not propose separate equipment classes based upon kVA capacity for liquid-immersed transformers in the January 2023 NOPR, DOE requested comment on any other categories of equipment that may warrant a separate equipment class. 88 FR 1722, 1752. DOE also evaluated a separate equipment class in the January 2023 NOPR for submersible distribution transformer based, in part, on the high overload capabilities and reduced heat transformer needed for many submersible distribution transformers which require manufacturers to increase no-load losses in order to decrease load losses. 88 FR 1722, 1748. Stakeholder feedback in response to the NOPR regarding the likely increase in loading—as summarized at the beginning of this section—and the conclusions from the additional studies described previously in this section regarding the likelihood of overloading a transformers in the near-term justify evaluating single-phase liquid-immersed distribution-transformers as two equipment classes based on kVA size, based on a similar principle that increased ability to overload a transformer requires trading no-load losses for load losses at intermediate efficiency levels.

c. Large Three-Phase Transformers With High-Currents

Distribution transformers with high currents often have increased stray losses, which can impact the efficiency of distribution transformers. Because of this limitation, NRCAN regulations exclude transformers with a nominal low-voltage line current of 4000 A or more. DOE has historically not evaluated high-current transformers as a separate equipment class.

In the January 2023 NOPR, DOE noted that while stray losses may be slightly higher for high-current transformers, manufacturers have the option to use copper secondaries or a copper buss bar to decrease load losses. 87 FR 1722, 1750. Further, DOE noted that technologies that increase the efficiency of lower-current transformers tend to also increase the efficiency of high-current transformers. *Id.* Therefore, DOE did not propose a separate equipment class for high-current transformers. However, DOE stated that it may consider a separate equipment class for high-current transformers if sufficient data were provided, and DOE requested manufacturers provide data on the different cost-efficiency curve associated with high-current transformers along with the number of shipments of these units. *Id.* at 87 FR 1751.

Eaton provided data showing the max-tech of their designs with both amorphous and grain-oriented electrical steel (GOES) cores with 208Y/120 secondaries and 480Y/277 secondaries. (Eaton, No. 137 at p. 17) Eaton's data showed that the max-tech is similar at low kVA values, regardless of secondary current. (Eaton, No. 137 at p. 17) Eaton additionally provided cost efficiency curves for 500 kVA units which showed similar incremental costs at the proposed standard levels for designs with either a 208Y/120 or a 480Y/277 secondary. *Id.* However, as the transformer capacity increases and the secondary current increases, the maximum transformer efficiency that can be achieved begins to drop considerably. *Id.*

Most distribution transformers are sold at one of a handful of standard secondary voltages. For three-phase transformers, this is typically either 480Y/277 or 208Y/120. Eaton stated that 97 percent of their three-phase shipments use either a 208Y/120 or 480Y/277 secondary. (Eaton, No. 137 at p. 20)

Eaton recommended DOE set an efficiency standard with at least a 20-percent margin in base losses relative to the actual max-tech for 208Y/120 secondary transformers. *Id.* Eaton suggested that DOE could propose separate standards for transformers with 480Y/277V or 208Y/120V secondaries based on having a line voltage above or below 250 V respectively. (Eaton, No. 137 at p. 29)

DOE notes that across all transformers, variability in voltage can impact the price and maximum achievable efficiency of a transformer. As shown in Eaton's max-tech plots, there is a slight difference in the maximum efficiency that can be achieved across all kVA ranges as the stray and eddy currents and conductor thickness will vary slightly between designs. Similarly, the choice in primary voltage may slightly impact the maximum achievable efficiency of a given transformer design. However, in general, these differences are not sufficient to warrant separate equipment classes. As discussed in Eaton's comment, for most kVA values there is sufficient ''margin'' that both a 208Y/120 and a 480Y/277 transformer have similar cost-efficiency relationships. Having a different equipment class for all possible kVA and voltage combinations is infeasible and was not suggested by any stakeholders.

Eaton additionally commented that its modeling of max-tech shows that previous DOE efficiency standards may have resulted in the unavailability of many 2,000 kVA and 2,500 kVA distribution transformers with 208Y/120 secondaries, which should not have been allowed under 42 U.S.C. 6295(o)(4), as this represents a performance characteristic. (Eaton, No. 137 at p. 18)

DOE notes that 42 U.S.C. 6295(o)(4) specifies that DOE may not set any amended standard that is likely to result in the unavailability of any performance characteristics that are substantially the same as those generally available in the United States at the time of the Secretary's finding. DOE notes that voltage generally increases as transformer capacity increases. As such, the high-current units cited by Eaton generally were not available due to the challenges of designing a transformer with a wire of sufficient thickness to handle the very high-currents. DOE does not expect that the adopted standards will result in the unavailability of any high-current units that are currently being produced in any significant volume. Further, there is no distinct purpose where such a large kVA transformer with such a high-current would be the only option to provide a low secondary voltage because consumers can and do achieve identical utility more economically and efficiently with one or multiple smaller kVA transformer placed closer to the electricity's end-use.

Transmission losses are also related to transformer current, and as such, if a customer needs a very large amount of transformative capacity, it is typically more efficient and cost effective to step-down power to 480V/277 and then use smaller transformers to further step down the voltage to 208Y/120, closer to the actual point of use. For these reasons, industry standards recommend high-kVA transformers have higher-secondary voltages. As such, currents do not tend to reach problematic values.

However, transformers within common industry values may still have a high enough current such that the stray and eddy losses would make up a much greater percentage of the transformer load losses and require manufacturers to overdesign transformers to meet a given efficiency level. Additionally, as kVA increases, this effect may become progressively more pronounced.

Prolec GE commented that load losses tend to be ten percent higher for high-current transformers due to increased losses in the leads and electrical connections on the secondary side of the transformer. (Prolec GE, No. 120 at pp. 6–7) Carte commented that using a 120V secondary instead of a 277V secondary for a 500 kVA, single-phase transformer would increase the cost to meet current efficiency standards by 52 percent. (Carte, No. 140 at p. 9) Carte commented that for 1,500 kVA three-phase transformer, using 208Y/120 secondary instead of a 480Y/277 secondary results in a 66 percent increase in first cost. Carte added that a 1,500 kVA three-phase unit with 208Y/120 design could at best achieve a 5 percent reduction in losses and would increase the cost by 95 percent relative to current efficiency standards, unless they transitioned to an amorphous core. (Carte, No. 140 at p. 9)

Several stakeholders gave specific low-voltage line-currents at which stray and eddy losses grow disproportionately. Howard commented that for three-phase transformers, it currently is difficult to meet efficiency standards for currents greater than 3000 A. Howard commented that typical load losses grow disproportionately at high current, wherein the load loss to no-load loss ratio is typically between 3–5 for low-current transformers but increases to 7–8 for high-current transformers, requiring higher grades of core steel to offset the increased load losses. Howard added that under the NOPR proposed levels, currents greater than 2000 A would be difficult. (Howard, No. 116 at p. 12) Prolec GE commented that above 3000 A, the manufacturer needs to overdesign the transformer or it becomes infeasible to meet efficiency levels. (Prolec GE, No. 120 at pp. 6–7) NEMA commented that for, liquid-filled transformers, it is difficult to meet current energy conservation standards above 4000 A today and recommended DOE not increase efficiency standards for any transformers with a low voltage line current over 3000 A. (NEMA, No. 141 at p. 11)

The current limits mentioned by stakeholders typically correspond to a specific common kVA value and common secondary voltage. For example, a low-voltage line current of 2,000 A or greater corresponds to 3-phase transformers with either a 208Y/120 secondary voltage and a capacity of 750 kVA or transformers with a 480Y/277 secondary voltage and a capacity of 2,000 kVA. A low-voltage line current of 3,000 A or greater corresponds to transformers with a 208Y/120 secondary voltage and capacity greater than 1000 kVA or transformers with a 480Y/277 secondary voltage and a capacity of 2,500 kVA. A low-voltage line current of 4,000 A or greater corresponds to transformers with a 208Y/120 secondary voltage and capacity of 1,500 kVA or transformers with a 480Y/277 secondary voltage and a capacity of 3,750 kVA.

IEEE C57.12.36–2017 recommends a minimum low-voltage of 277V beginning at 1,500 kVA and a minimum of 1386V beginning at 5,000 kVA. Similarly, IEEE C57.12.34–2022 recommends a maximum kVA of 1,000 kVA for a 208Y/120 or 240V secondary. As such, the only IEEE standard recommended products with a 208Y/120 or 480Y/277 secondary above 2,000 A include 750 kVA and 1,000 kVA transformers with 208Y/120 secondaries and 2,000 kVA; 2,500 kVA; and 3,750 kVA with 480Y/277 secondaries. The only recommended products above 3,000 A include a 2,500 kVA and 3,750 kVA with a 480Y/277 secondary. The only recommended products above 4,000 A include a 3,750 kVA with 480Y/277 secondary. DOE notes that 3,750 kVA transformers are not currently subject to energy conservation standards but were proposed to be covered in the January 2023 NOPR.

Regarding transformers with low-voltage line currents exceeding 2,000 A that stakeholders identified as having a harder time meeting standard, Eaton's data suggests that the DOE modeled max-tech closely aligns with manufacturer data for the 2,000 kVA and 2,500 kVA transformers with 480Y/277 secondaries.

Howard commented that 4.8 percent of their three-phase transformer shipments exceed 2000 A. (Howard, No. 116 at p. 12) Howard did not give specifics as to which of those also exceed 3,000 A or 4,000 A; however, based on industry standards, DOE expects most of those units to be 2,000 kVA and 2,500 kVA transformers with 480Y/277 secondaries.

Eaton provided data showing that as transformer capacity increases, the percentage of units with the higher secondary, and therefore lower current, increases such that at 1500 kVA, only 7.9 percent of units have 208Y/120 secondaries, and at 2,000 kVA and above, 0 percent of shipments have 208Y/120 secondaries. (Eaton, No. 137 at p. 20)

The data supplied by Eaton indicates that, for lower kVA capacities, transformer max-tech efficiency increases with kVA as predicted in DOE's modeling. However, above a certain point, the transformer begins to reach the limits of its design capabilities and max-tech efficiency begins to decline, rather than increase. Eaton's data suggest that this design limit can vary by steel variety, but for grain oriented electrical steel begins at 500 kVA for a 208Y/120 secondary voltage, corresponding to a line current of 1,389 A. (Eaton, No. 137 at p. 18)

Further, the normal impedance range for transformers as specified in IEEE Standard C57.12.34 changes from 1.2%–6.0% below 500 kVA to 1.5%–7.0% at 500 kVA.[54] Although impedance does

[54] IEEE SA. (2022). IEEE C57.12.34–2023—IEEE Standard Requirements for Pad Mounted, Compartmental-Type, Self-Cooled, Three-Phase

not necessarily correlate to transformer efficiency, as discussed in section IV.C.1.d, designing to a higher impedance range leaves transformer with less design flexibility to meet amended efficiency standards.

Based on the increase in stray and eddy losses associated with high-current and the change in impedance range, DOE has concluded that transformers greater than 500 kVA warrant a separate equipment class. Specifically, DOE has evaluated two equipment classes for three-phase liquid-immersed distribution transformers based upon capacity. Equipment Class 2A corresponds to three-phase liquid-immersed distribution transformers ranging from 15 to less than 500 kVA. Equipment Class 2B corresponds to three-phase liquid-immersed distribution transformers greater than or equal to 500 kVA).

Regarding further separation of large three-phase kVA transformers based on current, DOE acknowledges that high-current transformers may experience greater challenges in meeting amended efficiency standards and higher-current transformers tend to correspond to larger kVA sizes. However, DOE analyzed the incremental costs associated with three-phase 1,500 kVA units at 208Y/120 secondaries as compared to 480Y/277 secondaries. These results are discussed in Chapter 5 of the TSD. DOE has determined that both units are capable of meeting amended efficiency standards and therefore concluded that a transformer with a higher-current does not justify having a lower efficiency standard than transformers with lower-currents. Therefore, DOE has not established a separate equipment class for high-current transformers.

d. Multi-Voltage Capable Distribution Transformers

DOE's test procedure section 5.0 of appendix A requires determining the efficiency of multi-voltage-capable distribution transformers in the configuration in which the highest losses occur. In the August 2021 Preliminary Analysis TSD, DOE acknowledged that certain multi-voltage distribution transformers, particularly non-integer ratio distribution transformers, could have a harder time meeting an amended efficiency standard as it results in an unused portion of a winding when testing in the highest losses configuration and therefore reduces the measured efficiency. (August 2021 Preliminary Analysis TSD at pp. 2–21) In response to the August 2021 Preliminary Analysis TSD, DOE received comment reiterating that these transformers may experience additional losses which could make it more difficult to comply with standards, particularly when tested in the lower voltage configuration. (Schneider, No. 49 at p. 9; ERMCO, No. 45 at p. 1; NEMA, No. 50 at p. 6; Eaton, No. 55 at p. 12)

In the January 2023 NOPR, DOE discussed how multi-voltage distribution transformers, and specifically those with non-integer ratings, offer the performance feature of being able to be installed in multiple locations within the grid (such as in emergency applications) and easily upgrade grid voltages without requiring a replacement transformer. 88 FR 1722, 1750. DOE also acknowledged that these distribution transformers often have additional, unused winding turns when operated at their lower voltage, increasing the transformer losses. *Id.*

However, DOE noted that the efficiency of these transformers will increase once the distribution grid is increased to the higher voltage rating and the entire winding is used. Further, stakeholder comments suggested that the difference in losses associated with multi-voltage distribution transformers is relatively small. DOE also noted that the same technologies that increase the efficiency of single-voltage distribution transformers can be used to increase the efficiency of multi-voltage distribution transformers, meaning that the efficiency of either product could be increased via the same methods to meet amended standards. *Id.* Therefore, DOE did not propose a separate equipment class for multi-voltage-capable distribution transformers with a voltage ratio other than 2:1 but requested comment and data on the number of shipments for and degree of additional losses experienced by these products.

Howard commented that dual voltage transformers can increase load losses by 5–24 percent, requiring transformers to be overdesigned and possibly limiting manufacturers' ability to offer certain designs. Howard additionally commented that dual voltage ratios other than 2:1 represent less than 10 percent of shipments for all equipment classes. (Howard, No. 116 at pp. 11–12)

NEMA commented that it is difficult to say exactly how load loss changes with multi-voltage transformers and estimated that fewer than 2 percent of shipments are multi-voltage transformers with ratios other than 2:1. (NEMA, No. 141 at p. 10)

Eaton commented that load loss data for transformers with a voltage ratio other than 2:1 may not show a meaningful trend because load losses are adjusted based on the no-load losses to meet standards. Instead, Eaton provided cost versus efficiency data for 500 kVA transformers which indicated that transformers with a voltage rating other than 2:1 are capable of achieving effectively the same efficiencies as transformers with a single voltage rating. The data provided also indicated that the proposed efficiency levels could be met at a similar incremental cost for either a multi-voltage or single-voltage transformer. However, Eaton went on to state that this may vary across voltage and kVA ratings and that there is insufficient data to draw broad conclusions. (Eaton, No. 137 at pp. 14–15) Eaton additionally commented that they construct a considerable number of dual-voltage units, and provided data stating that 13.9 percent of their single-phase units and 4 percent of their three-phase units have non-2:1 voltage ratios. (Eaton, No. 137 at p. 15)

Carte commented that the cost to meet proposed efficiency levels with a GOES transformer increases substantially for dual- and multi-voltage transformers. (Carte, No. 140 at p. 9)

As described in section IV.A.2.d of this document, DOE may establish a separate equipment class for a product if DOE determines that separate standards are justified based on the type of energy used, or if DOE determines that a product's capacity or other performance-related feature justifies a different standard. DOE acknowledges that multi-voltage capable distribution transformers may provide a unique utility in allowing the grid to be upgraded to higher voltages without requiring that a transformer be replaced. As grid modernization continues to occur and as consumer loading increases, this utility may provide a unique benefit to utilities by enabling them to utilize transformers to the full extent of their lifetime and avoid early replacements.

However, DOE has not determined that this feature results in multi-voltage capable transformers being significantly disadvantage in meeting amended standards. DOE evaluated available loss data obtained from publicly available utility bid data for liquid-immersed distribution transformers and found distribution transformers with multi-voltage ratings, both in integer and non-integer ratios, occupying the same design space as general use transformers across all kVA sizes. (See chapter 5 of

Distribution Transformers, 10 MVA and Smaller; High-Voltage, 34.5 kV Nominal System Voltage and Below; Low-Voltage, 15 kV Nominal System Voltage and Below. Available at *https://standards.ieee.org/ieee/C57.12.34/6863/* (last accessed Nov. 8, 2021).

the TSD for additional detail). As pointed out by Howard, multi-voltage capable transformers may need to be overdesigned to meet standards at both the higher and lower voltage rating. While this might lead to a higher base cost for these transformers, available data does not indicate that the incremental cost to meet amended efficiency standards for these units would be higher. This is illustrated by the data provided by Eaton, which shows that multi-voltage capable distribution transformers are often more expensive at baseline but follow similar cost-efficiency curves. Eaton's data also indicated that multi-voltage capable distribution transformers, including those with non-integer ratios, can be designed to meet the same efficiencies as distribution transformers with single-voltage ratings up until the edge of max-tech.

Therefore, for the reasons discussed, DOE is not creating a separate equipment class in this final rule for multi-voltage capable distribution transformers with non-integer ratios.

e. Data Center Distribution Transformers

As noted in the January 2023 NOPR, DOE considered a separate equipment class for data center distribution transformers in the April 2013 Standard Final Rule, defined as the following:

''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 inrush 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

(iii) 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.''[55]

In the April 2013 Standards Final Rule, DOE did not adopt this definition of ''data center distribution transformers'' or establish a separate class for such equipment for the following reasons: (1) the considered definition listed several factors unrelated to efficiency; (2) the potential risk of circumvention of standards and that a transformer may be built to satisfy the data center definition without significant added expense; (3) operators of data centers are generally interested in equipment with high efficiencies because they often face large electricity costs, and therefore may be purchasing at or above the standard established and unaffected by the rule; and (4) data center operator can take steps to limit inrush current external to the data center transformer. 78 FR 23336, 23358.

In the August 2021 Preliminary Analysis TSD, DOE stated that data center distribution transformers could represent a potential equipment class-setting factor and requested additional data about the data center distribution transformer market, performance characteristics, and any physical features that could distinguish data center distribution transformers from general purpose distribution transformers. (August 2021 Preliminary Analysis TSD at pp. 2–22) However, DOE did not receive any comments as to physical features that could distinguish a data center distribution transformer from a general purpose distribution transformer.

[55] 78 FR 23336, 23358.

In the January 2023 NOPR, DOE did not propose a definition for data center distribution transformers and did not evaluate them as a separate equipment class. However, DOE noted that it may consider a separate equipment class if provided sufficient data to demonstrate that data center transformers warrant a different efficiency level and can appropriately be defined. 88 FR 1722, 1751. Accordingly, DOE requested comment on its proposal not to establish a separate equipment class for data center distribution transformers and on any identifying features related to efficiency which would prevent a data center transformer from being used in general purpose applications. *Id.*

ABB SP commented that it supports a separate equipment class for data center transformers with standards maintained at the current levels. (ABB SP, No. 110 at pp. 1–2)

DOE noted that distribution transformers used in data centers may sometimes, but not necessarily, be subject to different operating conditions and requirements which carry greater concern surrounding inrush current. 88 FR 1722, 1751. DOE requested comment on the interaction of inrush current and data center distribution transformer design. *Id.*

Regarding the specific challenges related to inrush current for data center distribution transformers, Schneider and NEMA commented that because of the frequent energizing of data center transformers, designers typically seek to limit inrush to prevent nuisance trips of the system. However, both Schneider and NEMA further stated that the concerns for data center transformers inrush current are similar to the concerns for all LVDTs, and while inrush is often related to installation and restoration after power loss, increased adoption of alternate power systems will mean more general purpose LVDTs will have concerns when power is transferred from one source to another. (Schneider, No. 92 at p. 6; NEMA, No. 141 at p. 12)

Regarding inrush current more broadly, Schneider and NEMA commented that the maximum inrush must be less than the over current trip value. (Schneider, No. 101 at pp. 6–8; NEMA, No. 141 at pp. 12–13) Schneider and NEMA further stated that inrush current can be limited using lower quality steel, modifying coil windings, and modifying core configurations. *Id.* Schneider and NEMA commented that nuisance tripping can be addressed by adding circuit resistance during energization of transformers, using electronic circuit breakers with adjustable trip settings, designing electrical system with the maximum allowed overcurrent protective device; however, all these approaches would add cost. *Id.*

Schneider commented that while DOE assumes equipment will be redesigned or modified to handle inrush, the market has not yet started this analysis. (Schneider, No. 101 at pp. 12–13) Schneider stated that the 2016 standards increased the size of the primary over current protection device near the limits set by the National Electric Code. Schneider commented that customers today can use electronic trip breakers or secondary breakers to address inrush concerns, but those solutions may not be suitable for the amended efficiency levels. *Id.*

ABB SP commented that data center transformers must be designed to account for inrush both during startup and during operation when part of the electrical system fails, and power is diverted to a redundant component. (ABB SP, No. 110 at p. 2) ABB SP stated that, while upstream infrastructure could be upsized to accommodate inrush current, this would decrease overall data center efficiency and consume more energy. *Id.*

APPA commented that higher inrush currents may require a change of protective equipment, such as relays, at a higher cost. (APPA, No. 103 at p. 13) APPA further stated that there is insufficient data on how to size protective devices for higher inrush, which will lead to transformer failure or excessive device tripping. *Id.* APPA stated that, in either scenario, excess fuse tripping will lead to millions of dollars of additional costs. *Id.* As such, APPA commented that DOE should publish protection standards and short circuit information prior to any changes and give a 4-year lead tie for industry to gain experience with amorphous transformers. *Id.*

Eaton commented that general use LVDT transformers can be designed to generate inrush currents up to 25x rated current, but data center transformers cannot exceed 8x rated current to avoid potential power outages. (Eaton, No. 137 at p. 34) Eaton further commented that traditional inrush current limiting schemes, such as impedance insertion, are not viable for data center transformers because they starve the critical load of rated operating voltage. *Id.* Eaton stated that mitigating inrush current by controlling transformer energization is also not feasible for data center transformers because the required equipment would delay energization. *Id.*

Prolec GE commented that the inrush current limit is 25x rated current for both data center transformers and general-use transformers as defined in IEEE standard C37.48.1. (Prolec GE, No. 120 at p. 7) Prolec GE commented that peak inrush current is determined by the air core inductance [56] and not the core steel. *Id.* Prolec GE also stated that technologies to mitigate inrush current have high complexity, low reliability, and high costs. *Id.* Prolec GE also stated that the relationship between operational flux density and remanence [57] matters more with regard to inrush current than the absolute magnitude of remanence. *Id.*

Stakeholder comments suggest that inrush current concerns may be of particular importance for data center distribution transformers, due to the sensitive nature of the equipment placed downstream of the transformer. Stakeholder comment also suggest that increased efficiency standards can increase the likelihood of inrush conditions exceeding the limitations of standard protective equipment, depending on how the flux density and construction of the core are modified to increase transformer efficiency.

However, increased inrush current is not guaranteed to occur because of increasing transformer efficiency and is partially within the control of the transformer designer. For example, designing a transformer with a lower flux density decreases the likelihood and magnitude of inrush current occurrences. Stakeholder feedback indicates that technologies exist to limit and protect against inrush current in situations when the transformer design cannot be modified to do so. Therefore, DOE does not consider inrush current to be an inhibiting factor which would prevent transformer manufacturers from meeting amended efficiency standards.

In the January 2023 NOPR, DOE also requested comment on the specific challenges that might arise with designing data center distribution transformers with cores made of amorphous cores. 88 FR 1722, 1751.

Metglas commented that it is not aware of any technical issues to prevent the use of amorphous transformer cores in data center applications. (Metglas, No. 125 at p. 5) Metglas commented that inrush current varies based on impedance for amorphous transformers and is not 20 percent different than for a GOES unit at the same impedance. (Metglas, No. 125 at p. 5)

Howard commented that it is unaware of any challenges with data center transformers and is not aware of amorphous core transformers being built for the data center market. (Howard, No. 116 at p. 13)

Schneider, Eaton, and NEMA stated that the inherent air gaps, high saturation flux density, and lower remnant flux density of stacked core construction cores helps limit inrush currents, but would no longer be viable under the proposed standards since amorphous can only be used in wound cores. (Schneider, No. 92 at p. 6; NEMA, No. 141 at p. 11; Eaton, No. 137 at p. 37) Eaton commented that using amorphous in data center transformers in PDUs will require significant research and development because each of these units has specific requirements and cannot be standardized. (Eaton, No. 137 at p. 3)

Eaton commented that, due to the increased remnant flux and reduced saturation flux density, a data center transformer designed with an amorphous core would need to operate at about 9 to 12.6 kG to keep inrush current within the 4–8X limit. (Eaton, No. 137 at p. 35) Eaton stated that inrush current may be reduced for wound core amorphous transformers by increasing the winding turns to increase air core inductance, but this also increases load losses, impedance, winding temperature rise, and cost. *Id.* ABB SP further commented that the lower flux density of amorphous cores would require manufacturers of data center transformers to choose between higher inrush currents during emergency power transfers, longer transfer times, or significantly larger core and coil size. (ABB SP, No. 110 at p. 2)

DOE received several comments stating that higher efficiency units, and specifically amorphous core transformers, are less efficient at higher loading than conventional GOES transformers. For dry-type units, Eaton commented that PDU transformers designed to meet DOE standards at 35 percent loading are less efficient during typical operation at 60–80-percent load and this problem will be exacerbated by amorphous. (Eaton, No. 137 at p. 37) NEMA and Schneider commented that

[56] The air core inductance of transformer represents the properties of the winding if there were no core to induce (*i.e.,* using an ''air core''). Peak inrush can be approximated based on the air core inductance because when a transformer is pushed into saturation conditions, which is when maximum inrush would occur, the instantaneous induction of the core is very low, allowing it to be modelled as an air core.

[57] Operational flux density represents the max flux density at which a transformer is designed to operate, whereas remanence represents the magnitude of flux density that remains in a core after being de-energized. Both the remanence and the operational flux density must be considered when designing a transformer such that the core will not be pushed above its saturation flux density during normal operation, which can lead to very high inrush current and potentially damage the transformer or downstream equipment.

amorphous cores have not been used in data center applications and would not maximize savings because average loading is typically 65–80 percent. (Schneider, No. 92 at p. 6; NEMA, No. 141 at p. 11)

Powersmiths commented that the proposed efficiency standards at 35 percent loading will significantly increase losses in high load applications, such as data centers. (Powersmiths, No. 112 at p. 5) Accordingly, Powersmiths recommended that DOE consider a provision to accommodate high transformer load applications, such as exemptions for specific use cases or different requirements at a higher load point. *Id.*

Regarding stakeholder comment that data center distribution transformers transformer loading may be higher than general purpose transformers, DOE agrees that operating conditions with higher loading applications benefit less from reduced no-load losses. However, DOE disagrees that amorphous cores inherently are less efficient at higher loading. As discussed in section IV.C.1, amorphous transformers are not inherently designed with higher load losses. The reduced no-load losses for amorphous transformers provide additional design flexibility in meeting efficiency standards, often resulting in higher load losses to reduce costs in a minimally compliant amorphous transformer. However, amorphous transformers can be designed to target lower load losses, just as GOES transformers can. Further, DOE's modeling includes a variety of designs at higher efficiency levels, some with higher load losses and some with lower load losses. Hence, manufacturers have the capability to redesign transformers to meet higher efficiency standards either by reducing the no-load losses, reducing the load losses, or reducing some combination of the two.

DOE received additional comments that amorphous-core transformers in data center applications would be larger, which could create additional challenges.

For liquid-immersed units, Eaton stated that most of its data center transformers are in the size range of 2,500 to 3,500 kVA, which is outside the current range of transformer sizes that Eaton designs with amorphous cores. (Eaton, No. 137 at p. 21) Eaton also commented that the larger size of wound core amorphous transformers will increase the size of PDUs and go against Data Centers Industry efficiency goals for high power density per unit area. (Eaton, No. 137 at pp. 37–38) Eaton further stated that wound core designs may have difficulty meeting specific PDU requirements due to reduced design flexibility and greater likelihood of DC and/or subharmonic voltages issues resulting from the lack of air gaps. (Eaton, No. 137 at p. 38)

ABB SP commented that the increased volume of data center transformers designed with amorphous cores would increase load losses, strain the elevated floor systems common for PDU's, and remove the ability to replace transformers at the end of life due to other necessary changes to accommodate the increased volume. (ABB SP, No. 110 at p. 2)

As indicated by stakeholders, amorphous metal is not commonly utilized in the U.S. data center distribution transformer market today, resulting in limited data from manufacturers available to assess the performance of amorphous units in data center applications. Stakeholder comments identified challenges with using amorphous core transformers related to transformer inrush and transformer size. Stakeholder comment suggests that those challenges could be overcome, such as reducing an amorphous cores flux density or modifying protective equipment. However, these changes may have additional costs. Further, many of those challenges identified for data center transformers were noted as existing for all LVDTs, not something necessarily unique to data center transformers.

In DOE's review of the international market DOE observed several manufacturers marketing dry-type transformers with an amorphous metal core.[58] [59] [60] [61] DOE also observed marketing of amorphous core transformers being used in data centers.[62] [63] The existence of amorphous metal cores in dry-type distribution transformers, and particularly in LVDT distribution transformers, demonstrates the technological feasibility of converting to amorphous. While stakeholders indicated that data center distribution transformer may be subject to additional design constraints, commenters did not provide data to demonstrate how these design constraints may be impacted when using amorphous metal or specifics as to what these additional costs would be and when they come into effect (*e.g.* only beyond certain kVA sizes, only in certain applications, *etc.*). As such, DOE has concluded that there is insufficient data to warrant a separate equipment class for data center transformers.

Stakeholders also commented as to what physical features of data center transformers could be identified to define data center transformers as an equipment class separate from other general purpose distribution transformers.

ABB SP commented that data center transformers are primarily distinguished from general purpose LVDT transformers by their application, with most data center transformers used in PDU's. *Id.* ABB SP stated that transformers used in PDUs must be designed to accommodate specific system requirements, including power quality requirements, exposure to harmonic sources, continuous loading at 50–90 percent, and the ability to supply a diverse variety of power sources without going into saturation or changing tap connections. *Id.* ABB SP also commented that since 2013, data center transformers have become larger, begun using elevated secondary voltage ratings, are designed with greater protections for arc flash and fault current, and are designed at higher ambient temperature. *Id.*

Eaton recommended that DOE specifically exempt low-voltage transformers used in PDUs for data centers. (Eaton, No. 137 at p. 2) Eaton commented that data center transformers are not sold as standalone equipment but rather as part of power distribution units (PDUs). (Eaton, No. 137 at p. 34) Eaton further commented that data center transformers have specific design requirements which distinguish them from general-purpose units, including (1) an inrush current rating of 8x or lower, (2) a higher k-factor to accommodate non-linear loads, (3) a requirement for two electrostatic

[58] Toyo Electric, *Dry-Type Amorphous Core Transformer.* Available at: *www.toyo-elec.co.jp/products/download/catalog/transform/Amorphous_EN.pdf* (last accessed Nov. 7, 2023).

[59] Jiangsu Ryan Electric Company, *SCBH15, SGBH15, SCBH16, SGBH16 amorphous alloy dry-type transformer.* Available at *en.redq.cc/SCBH15-SGBH15-SCBH16-SGBH16-amorphous-alloy-dry-type-transformer-pd49182496.html* (last accessed Nov. 7, 2023).

[60] Yuebian Electric, *Amorphous Alloy Dry Type Transformer.* Available at *www.zjyb-electric.com/products/amorphous-alloy-dry-type-transformer.html* (last accessed Nov. 7, 2023).

[61] China Electric Equipment Group, *Amorphous Alloy Dry Type Transformer Three Phase Power Transformer Factory.* Available at *ceegtransformer.com/products/amorphous-alloy-dry-type-transformer-three-phase-power-transformer-factory* (last accessed Nov. 7, 2023).

[62] CEEG, *42 Units of CEEG Amorphous Alloy Transformers For Data Center were Successfully Energized.* Available at *www.cnceeg.com/news/42-units-of-ceeg-amorphous-alloy-transformers-48777661.html* (last accessed Nov. 7, 2023).

[63] Qingdao Yunlu Advanced Materials Technology Co. Ltd. *Introduction to Amorphous Alloy Core.* Available at *www.yunluamt.com/product-44-1.html* (last accessed Nov. 7, 2023).

shields connected to the ground,[64] (4) increased insulation inside the winding and increased clearances from the winding to ground to improve reliability, (5) and an occasional requirement for a lower temperature rise, which is becoming increasingly common in data center design. (Eaton, No. 137 at pp. 34–36) Eaton also commented that wide range of impedance requirements can make it difficult to design PDU transformers which both comply with DOE standards and meet k-factor specifications. (Eaton, No. 137 at p. 36) Eaton additionally commented that data center transformers must be operated using low flux and current densities to meet standards, which is an inefficient use of resources. (Eaton, No. 137 at p. 36)

Schneider commented that a separate equipment class is not required for data center transformers as it opens the door to many other industry segments requesting exclusions. (Schneider, No. 92 at pp. 4–5) Schneider commented that there are attributes for data center transformers that may make it more difficult to comply with energy conservation standards; however, these difficulties may be reduced with higher efficiency levels. *Id.* Schneider gave the example of K-ratings not being necessary for higher efficiency transformers because the thermal characteristics are no longer the limiting factor of kVA. *Id.* Schneider further commented that many of the concerns seen by the data center market would exist for all applications. *Id.* Schneider commented that the only way to prevent data center transformers from being used in general purpose applications would be to limit the secondary voltage to certain values. *Id.* Schneider also stated that requiring a secondary winding arrangement that is not delta or wye, as proposed in the April 2013 Standards Final Rule, relates to efficiency in that the efficiency of a transformer with a zig-zag secondary is less impacted under harmonic loading. *Id.*

Howard commented that no guidelines are needed to prevent data center transformers from being used in general purpose applications. (Howard, No. 116 at p. 13) Metglas commented that there does not seem to be a technical distinction between a data center transformer and a standard transformer. (Metglas, No. 125 at p. 5)

DOE recognizes that distribution transformers used in data center applications may be subject to unique requirements separate from those used in general-purpose applications, such as specific size constraints or a need for a higher k-factor. However, when establishing separate equipment classes for product groups, DOE is required to focus on capacity and performance related features that impact consumer utility. As indicated by stakeholders, the primary distinguisher between data center distribution transformers and general-purpose distribution transformers is their installation location, not the capacity or features of the transformer itself.

Further, in its review of manufacturer literature, DOE observed multiple manufacturers advertising general use transformers specifically designed with higher k-factor ratings, low inrush current, and/or electrostatic shields, all of which are design features suggested by commenters as being characteristic of data center transformers. As stated by Schneider, a number of applications, such as LVDT transformers used in hospital units, may require similar design requirements to those specified for data center transformers.

While some commenters provided specific features attributable to data center transformers, DOE notes that the majority of these features are not unique to data center distribution transformers. For example, several stakeholders indicated that data center distribution transformers must be designed with a higher k-factor to accommodate harmonic loading. In support of this claim, Eaton provided data comparing size and efficiency of DOE's modeling to k-factor rated transformers. However, Eaton's data did not demonstrate how an amorphous data center transformer would perform in this comparison. As stated by Schneider, the increased efficiency and reduced losses of an amorphous transformer would reduce the excess heat dissipation in a transformer, potentially reducing the need for higher k-factors.

In this final rule, DOE is not establishing a separate equipment class for data center distribution transformers. Based on the feedback received, DOE maintains that there are not sufficient physical features to differentiate data center distribution transformers from general-purpose distribution transformers. DOE does not have sufficient data to indicate that the characteristics that often distinguish a distribution transformer used in data center applications from one used in general purpose applications, such as a higher k-factor, would inhibit these units from being designed to meet an amended efficiency standard. Therefore, for the reasons discussed, DOE is not establishing a separate equipment class for data center transformers in this final rule.

While stakeholders did identify legitimate challenges associated with data center transformers, most stakeholders noted that they could be overcome. However, there is uncertainty as to the downstream impacts on protective equipment and transformer sizes, along with uncertainty of the costs associated with overcoming those challenges. For example, in circumstances when inrush current may become a concern for data center applications, additional measures may be taken to mitigate inrush conditions, both regarding the design of the transformer and the external technologies that could be applied. However, the degree of difficulty associated with each of these challenges is largely dependent on the compliance period with which stakeholders must meet amended efficiency standards and the degree of efficiency improvement of any proposed standards. DOE notes that the compliance period in this final rule is longer than the proposed in the NOPR and efficiency levels for LVDT units is lower than was proposed in the NOPR, indicating that manufacturers will have both more time and more design flexibility to overcome the challenges identified in response to the NOPR. DOE further notes that its adopted energy efficiency standards are achievable using many designs with continued usage of stacked core GOES designs, wherein manufacturers have considerable experience in designing data center transformers.

f. BIL Rating

Distribution transformers are built to carry different basic impulse insulation level (BIL) ratings. BIL ratings offer increased resistance to large voltage transients, for example, from lightning strikes. Due to the additional winding clearances required to achieve a higher BIL rating, high BIL distribution transformers tend to be less efficient, leading to higher costs and potentially more difficulty in achieving higher efficiencies. DOE currently separates medium-voltage dry-type distribution transformers into equipment classes based on BIL ratings, with classes for transforms with BIL ratings ranging from 20–45 kV, 46–95 kV, and above 96 kV. 10 CFR 431.196(c).

In the January 2023 NOPR, DOE discussed stakeholder comments which indicated that transformers with high BIL designs (≥150 BIL or ≥200 BIL) may experience higher losses that could inhibit them from meeting amended efficiency standards. 88 FR 1722, 1752.

[64] Eaton commented that this is a unique requirement for all PDU transformers (Eaton No. 137 at p. 36)

However, because no stakeholders provided data to indicate the degree to which transformers with high BIL ratings may be disadvantaged and because separating liquid-immersed transformers by BIL rating would add additional complications for potentially minor differences in losses, DOE did not propose separate equipment class based on BIL rating for liquid-immersed units.

In response to the January 2023 NOPR, DOE received several additional comments pertaining to BIL ratings for liquid-immersed distribution transformers.

Eaton commented that smaller kVA units with higher-voltage primary ratings, and corresponding higher BIL ratings, are more expensive to build; however, Eaton went on to state that these units are generally outside of the scope of what is commonly manufactured by Eaton. (Eaton, No. 137 at p. 21) Eaton added that the max-tech efficiency of a 500 kVA unit was similar for either a lower or higher BIL rating. (Eaton, No. 137 at p. 21)

Prolec GE commented that higher BIL designs have increased core and coil dimensions to account for the additional insulation needed, increasing the transformer losses. (Prolec GE, No. 120 at p. 8) Howard commented that each BIL increase results in a 0.02–0.07 percentage point drop in efficiency. (Howard, No. 116 at p. 13)

Carte commented that the increase in cost to meet the same efficiency for 200 kV BIL designs is the following: (1) a 20 percent increase relative to DOE's modeled 500 kVA, single-phase, 150 kV BIL design; (2) a 5 percent increase relative to DOE's modeled 150 kVA, three-phase, 95 kV BIL design; and (3) 16 percent increase relative to DOE's modeled 1,500 kVA, three-phase, 125 kV BIL design. (Carte, No. 140 at pp. 8–9)

To assess whether liquid-immersed units with high BIL ratings warranted being regulated under a separate equipment class, DOE evaluated publicly available utility bid data to investigate the performance of otherwise equivalent transformers with different BIL ratings. Based on this review, DOE observed designs with high BIL ratings (≥150 BIL) meeting higher efficiencies at a variety of kVA sizes. As stated by several stakeholders, units with higher BIL ratings may have a higher cost associated with them due to the added insulation and increased overall size of the unit. While the baseline cost for a high BIL unit may be greater than that for a lower BIL rating, DOE data indicates that the incremental cost to meet the amended efficiency standards would be similar for a transformer with a high BIL rating as opposed to one with a lower BIL rating. As such, DOE does not expect the consumers to lose access to the utility associated with high BIL designs absent designation in a new separate class.

Further, DOE notes that the cost increases and efficiency decreases referenced by stakeholders most likely assume that higher efficiencies are being achieved using a GOES core. DOE notes that its analysis shows that max-tech efficiency designs are able to reduce losses by considerably more than both the proposed standards for liquid-immersed distribution transformers and the adopted standards. While it may be considerably more expensive to have higher BIL designs with a GOES core at high-efficiency levels, manufacturers also have the option of using an amorphous core, which has a relatively flat cost-efficiency curve across significantly higher-efficiency levels.

Therefore, for the reasons discussed, DOE is not creating a separate equipment class based on BIL rating for liquid-immersed units in this final rule.

g. Other

DOE received additional comments discussing other potential equipment classes but generally did not receive any data regarding what technical features associated with these products warrant a separate equipment class.

NEMA commented that DOE should consider not including shovel transformers, above ground mining transformers, crane duty transformers, and marine application transformers. (NEMA, No. 141 at p. 13)

DOE notes that NEMA did not include any data or comment regarding the specific technical challenges this equipment would have in meeting efficiency standards or even suggest that these challenges exist. NEMA also did not provide comment regarding the physical features that would allow this equipment to be defined as compared to other general purpose distribution transformers. Therefore, DOE has not considered separate equipment classes for this equipment.

DOE received comment regarding triplex core transformers, which include three, single-phase core-coil assemblies grouped together to form a three-phase transformer. WEC commented that it commonly uses a triplex core design to prevent ferro resonance, which requires more pounds of core steel per kVA and could mean amended efficiency standards result in higher incremental costs. (WEC, No. 118 at p. 2) WEC commented that further increases in efficiency requirements could lead to the elimination of triplex core transformers, which would present additional operational and safety challenges to WEC employees and significantly extend outages to customers. *Id.* Howard supported creating a different equipment class for 3-phase pole mounted transformers because of their unique triplex design. (Howard, No. 116 at pp. 25–26) Howard additionally supported dividing pole and pad mounted transformers into separate equipment classes as utilities can more easily accommodate larger pad-mounted transformers. *Id.*

While triplex core transformers have more core steel per kVA than a traditional three-phase transformer, DOE did not receive any data as to the degree of difference. DOE notes that lower-loss core steel technology options would be expected to improve the performance of both traditional three-phase transformers and triplex core transformers. DOE's max-tech efficiency levels are typically met with amorphous cores, which would have lower no-load losses for both traditional three-phase transformer cores and triplex core transformers. Further, as WEC noted, triplex core transformers can be used in the exact same applications as three-phase pad-mounted transformers. For these reasons, DOE has not considered a separate equipment class for triplex core transformers. To the extent pole and pad-mounted transformers may have different installation challenges, those costs are accounted for in the installation costs, discussed in section IV.F.4 of this document.

Standards Michigan recommended DOE remove obstacles to manufacturers who choose to produce inexpensive, mobile transformers designed for the purpose of preventing civil unrest during major regional contingencies. Standards Michigan went on to state that these MRC transformers could be placed in a new product class. (Standards Michigan, No. 109 at pp. 1–2)

Utilities tend to keep distribution transformer reserves available for emergency situations, such as during a natural disaster or other storm. DOE notes that it develops separate equipment classes based on specific class-setting factors as set forth by EPCA, as described in section IV.A.2. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(1)). Standards Michigan did not identify any specific features associated with contingency transformers. Therefore, DOE has not established a separate equipment class for these contingency transformers.

3. Technology Options

In the preliminary market analysis and technology assessment, DOE identified several technology options initially determined to improve the efficiency of distribution transformers, as measured by the DOE test procedure.

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

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

Distribution transformer design is typically an optimization process. For a given core and conductor material, the mass and dimensions of the transformer core, winding material, insulation, radiators, transformer tank, *etc.,* can be varied to minimize costs while meeting a variety of design criteria. Within a manufacturer's optimization process, transformers can be designed to be minimally efficient or, if customers place a dollar value on electrical loss, can be designed to minimize the transformers total owning costs. Typically, small improvements in efficiency can be met with modest increase in material quantities; however, at some point, achieving any further increases in efficiency can substantially increases costs (*i.e.,* hitting the ''efficiency wall'' where costs rise dramatically for small increases in efficiency).

Once manufacturers have reached the ''efficiency wall'' for a given core and conductor material, the only realistic option for meeting higher efficiency values is to transition to core materials with lower no-load losses and/or transition from aluminum to copper winding material. The relative costs and availability of these lower-loss core materials has varied over time and is discussed in detail in section IV.A.4 of this document.

With respect to analyzed inputs, in the engineering analysis, DOE considered various combinations of the following technology options to improve efficiency: (1) Higher grade electrical core steels, (2) different conductor types and materials, and (3) adjustments to core and coil configuration.

4. Transformer Core Material Technology and Market Assessment

Distribution transformer cores are constructed from a specialty kind of steel known as electrical steel. Electrical steel is an iron alloy which incorporates small percentages of silicon to enhance its magnetic properties, including increasing its magnetic permeability and reducing the iron losses associated with magnetizing that steel. Electrical steel is produced in thin laminations and either wound or stacked into a distribution transformer core shape.

Electrical steel used in distribution transformer applications can broadly be categorized as either amorphous alloy or GOES. There are different subcategories of material performance within both amorphous alloy and grain-oriented electrical steel. In the January 2023 NOPR, DOE carried over the same naming convention developed in the August 2021 Preliminary Analysis TSD to identify the various permutations of electrical steel. 88 FR 1722, 1754.

DOE notes that producing distribution transformer cores with amorphous alloy requires different core production machinery than producing distribution transformer cores with GOES. As such, some amount of investment in machinery is required to transition between producing cores with amorphous alloy and GOES. Today, there are many equipment classes and kVA sizes where amorphous core transformers compete with GOES transformers on first cost. However, the vast majority of current core production equipment is set-up to produce GOES cores, and therefore the vast majority of transformer shipments use GOES cores even for products where using an amorphous core would lead to a lower first-cost to the consumer.

In meeting efficiency standards with GOES, DOE notes that using lower-loss GOES steel allows manufacturers to achieve modest improvements in efficiency with essentially identical designs (*e.g.,* essentially no increase in product weight, just a direct swap of higher-loss core steel with lower-loss core steel). However, there is a limited capacity of lower-loss GOES grades and only a single domestic manufacturer of GOES steel, which limits the availability of GOES products to distribution transformer manufacturers.

In achieving higher efficiencies without changing GOES steel performance, Eaton commented that manufacturers increase the core cross sectional area and decrease the flux density. (Eaton, No. 137 at pp. 21–22) The larger transformer cores require thicker conductors in order to maintain current density but using thicker conductors increases stray and eddy losses, which requires even larger conductor size to combat the additional stray and eddy losses. (Eaton, No. 137 at pp. 21–22) Eaton stated that at some point, the only option is to transition to copper windings, at which point the cost of the transformer skyrockets and significant cost increases are needed for even modest efficiency gains. (Eaton, No. 137 at pp. 21–22)

In other words, achieving higher efficiencies without reducing the losses of the core steel material is technically possible but gets increasingly difficult (in terms of significant increases in product weights and selling prices) as manufacturers attempt to reduce losses further.

If lower-loss GOES were widely available, distribution transformer manufacturers could achieve modest improvements in efficiency with essentially identical designs (*e.g.,* essentially no increase in product weight, just a direct swap of higher-loss core steel with lower-loss core steel). However, as with higher-loss GOES, beyond a certain point reducing losses further is technically possible but results in substantial increases in product weight and selling price.

In the current market, distribution transformer manufacturers limit themselves to the single domestic GOES manufacturer's product offerings and pricing, as any imported GOES steel is subject to a tariff that makes such steel uncompetitive. Therefore, increasing the domestic availability of lower-loss GOES steel depends on the investments in product quality made by the single domestic GOES manufacturer.

Amorphous cores reduce transformer no-load losses by approximately 50 to 70 percent relative to GOES (see Chapter 5 of the TSD for relative performance of amorphous- and GOES-based designs). This substantial reduction in no-load losses means that much higher efficiency standards can be achieved with amorphous cores (DOE's max-tech efficiency assumes use of an amorphous core) and there is more flexibility in designing transformers to meet efficiency standards (in terms of the weight and dimensions of the cores, amount of winding material, etc.).

However, the different production equipment associated with producing amorphous cores means that distribution transformer manufacturers must decide how to meet potential amended efficiency standards. If using amorphous cores, manufacturers would need to make substantial investments in amorphous core production equipment. In exchange, they would likely be able to sell many transformer ratings at a lower first cost and win business in doing so. Alternatively, manufacturers could continue to use existing GOES production equipment, however, they would likely be selling a transformer at a higher first cost.

For modest reductions in transformer losses (generally through EL2 for liquid-immersed distribution transformers and EL 3 for dry-type distribution transformers), the difference in first cost is not substantial enough to warrant the considerable investment in amorphous core production that is needed to meet efficiency standards. However, between EL2 and EL4 for liquid-immersed distribution transformers and EL3 and EL5 for dry-type distribution transformers, the size and weight increase associated with GOES cores become substantial and it generally becomes economically infeasible to continue producing GOES transformers unless consumers ignore product cost (*e.g.,* if shortages have forced consumers to purchase any transformer they can access, regardless of product costs).

DOE notes that in this final rule, it evaluated an additional TSL for liquid-immersed distribution transformers (TSL 3) that is a combination of proposed ELs, wherein some equipment classes are set at EL2 and other equipment classes are set at EL4. DOE notes that the ELs used in the final rule correspond to an identical reduction in losses as the ELs used in the January 2023 NOPR. However, the grouping of these ELs by equipment class has been modified in response to stakeholder feedback. In consideration of this feedback, for this final rule DOE regrouped the ELs that comprise TSL 3 such that EC1A and EC2A were evaluated at EL4, which is expected to predominantly be met via use of amorphous cores, while EC1B and EC2B were evaluated at EL2, which can be met via use of either GOES or amorphous cores. The new TSL 3 is intended to reflect stakeholder concerns that standards requiring substantial amorphous core production are not economically justified. As explained further below, TSL 3, which DOE is adopting in this final rule, is economically justified, technologically, feasible and maximizes energy savings without requiring an entire market transition to amorphous cores.

Under the adopted standard, the kVA ranges that will be required to meet EL4 represent only a portion of the overall distribution transformer market, and the volumes of amorphous steel required to supply this segment of the market is similar to the existing domestic amorphous ribbon production. As such, the adopted standard ensures that even absent significant growth in amorphous ribbon production, capacity in that market will be sufficient to meet demand in the transformer market. Further, the kVA ranges that have to meet EL2 approximately correspond with the existing domestic GOES production that serves the distribution transformer market. Accordingly, DOE has determined that this TSL ensures that manufacturers will not have to scrap existing production equipment. Rather, manufacturers of distribution transformers, amorphous ribbon, and GOES steel can all focus on and invest in increased production.

The various markets, technologies, and naming conventions for amorphous and GOES are discussed in the following sections, along with a discussion as to the expected variables manufacturers would consider in deciding how to meet amended efficiency standards.

a. Amorphous Alloy Market and Technology

Amorphous alloy [65] is a variety of core material that is produced by rapidly cooling molten alloy such that crystals do not form. The resulting product is thinner than GOES and has lower core losses, but it reaches magnetic saturation at a lower flux density.

DOE has identified three subcategories of amorphous alloy as possible technology options. These technology options and their DOE naming shorthand are shown in Table IV.4.

Table IV.4 Amorphous Alloy Technology Options

DOE Designator in Design Options	Technology
am	Traditional Amorphous Alloy
hibam	High-Permeability Amorphous Alloy
hibam-dr	High-Permeability, Domain-Refined, Amorphous Alloy

In the January 2023 NOPR, DOE discussed that it did not include any designs which utilized high-permeability amorphous because, although there are some design flexibility advantages to using high-permeability amorphous, it is only available from a single supplier. 87 FR 1722, 1754. DOE further noted that, in interviews, manufacturers had expressed a hesitance to rely on a single supplier of amorphous for any higher volume unit. *Id.* However, DOE also stated that hibam material can generally be used in place of standard am designs, though some specific applications may require redesigning. This assumption was supported by stakeholder comments in response to the August 2021 Preliminary Analysis TSD, as discussed in the January 2023 NOPR. 87 FR 1722, 1754–1755. Therefore, it is appropriate to include only standard am designs in the engineering analysis to avoid setting efficiency standards based on a steel variety, hibam, that is only available from a single supplier. Under this approach, manufacturers have the option to achieve efficiency levels that require am steel using either the standard am material or the hibam material depending on their sourcing practices and preferences. *Id.*

In the January 2023 NOPR, DOE also discussed the existence of a hibam material that uses domain refinement (''hibam-dr'') to further reduce core losses. 87 FR 1722, 1755. DOE stated that it had learned through interviews

[65] Throughout this rulemaking, amorphous alloy is referred to by stakeholders using various terms including ''amorphous'', ''amorphous alloy'', ''amorphous material'', and ''amorphous steel''. Each of these terms generally refers to amorphous ribbon which is then formed into an ''amorphous core'' that is used in the transformer.

that the hibam-dr product is not yet widely commercially available. As such, DOE did not include the hibam-dr product in its analysis because DOE could not verify that the core loss reduction of this product is maintained throughout the core production process and because it is only produced by one supplier. *Id.*

DOE notes that, since the publication of the January 2023 NOPR, it has identified additional amorphous suppliers who may offer high permeability grades, or potentially even high permeability domain refined grades.[66] [67] However, total capacity for these steels remains uncertain, potentially limiting their availability for use in the domestic distribution transformer market. Further, it is uncertain what the performance of amorphous ribbon would be from manufacturers with the technological know-how to produce amorphous [68] [69] but who do not currently produce wide-cast amorphous ribbon and may enter the market if demand for amorphous were to increase. Therefore, to allow greater design flexibility for manufacturers attempting to meet any amended standards, DOE has continued to exclude designs in the engineering analysis that use higher grades of amorphous.

Amorphous Technological Feasibility

In response to the January 2023 NOPR, DOE received additional comments regarding the performance of amorphous cores.

Powersmiths stated a concern that amorphous core transformers may exhibit certain performance defects when compared to GOES, including shards breaking off from the core, which may lead to premature failures and higher audible noise, making it more difficult or impossible to achieve NEMA ST–20 audible noise levels. (Powersmiths, No. 112 at pp. 2–3) Powersmiths additionally commented that there are many technical challenges with using amorphous cores, including non-homogenous flux distributions for wound cores, incompatibility with the cruciform structures required for larger kVA transformers, and greater difficulty in meeting standards for lower temperature units. Accordingly, Powersmiths commented that a wholesale conversion to amorphous material does not make sense given the limitations of the technology. (Powersmiths, No. 112 at p. 6)

Schneider commented that more research is needed into the inrush current, sound levels, and reduced impedance of amorphous. (Schneider, No. 101 at p. 2) Carte commented that amorphous transformers are louder than GOES transformers and questioned what the impacts of amorphous transformers would be on noise-sensitive areas. (Carte, No. 140 at p. 5) HVOLT commented that amorphous transformers create more audible noise. (HVOLT, No. 134 at p. 5) APPA commented that amorphous transformers produce more noise than GOES transformers, which would cause utilities to install transformers further away and increase secondary cable losses. APPA also stated that there are potential health impacts from higher levels of background noise. (APPA, No. 103 at p. 14) Idaho Power recommended DOE include weight, noise, and cost in its engineering analysis, stating that the proposed standards will likely result in the use of heavier, noisier, and costlier amorphous core transformers. (Idaho Power, No. 139 at p. 3)

AISI and Pugh Consulting both commented that amorphous is brittle and untested. (AISI, No. 115 at p. 2; Pugh Consulting, No. 117 at p. 5) Pugh Consulting additionally questioned whether amorphous transformers could be ''drop-in replacements'' for current transformers. (Pugh Consulting, No. 117 at p. 5)

Exelon commented that domestic manufacturers have limited experience making amorphous core distribution transformers, a deficiency in domestic manufacturing experience that could have significant cost, supply chain, and reliability implications. Exelon added that most uses of amorphous core transformers have been limited to kVA ratings below Exelon's needs and its current research suggests the use of amorphous transformers at higher ratings is essentially experimental. (Exelon, No. 95 at p. 3)

Metglas commented that amorphous core transformers accounted for approximately 10 percent of new installs in 1992 but became less common largely due to fewer utilities using a total owning cost (TOC) model. (Metglas, No. 125 at p. 2) Metglas further stated that amorphous transformers have served the electrical grid since 1982, with an estimated 22 million units in operation globally and approximately 1 million additional units brought online each year. *Id.*

Efficiency advocates commented that amorphous transformers are a proven technology, with an estimated 3 million transformers globally and over 90% of liquid immersed transformers in Canada utilizing amorphous cores. (Efficiency Advocates, No. 121 at pp. 1–2) NYSERDA similarly commented that transformers with amorphous cores are field proven and cost effective. (NYSERDA, No. 102 at pp. 2–3)

EMS Consulting commented that GE produced over 600,000 amorphous transformers between 1986 and 2001 with very satisfactory field experiences, indicating that amorphous transformers are a reliable product. (EMS Consulting, No. 136 at pp. 2–3) EMS Consulting added that deregulation of electrical industries in the 1990s reduced demand for amorphous products in the U.S., but the products became more popular in developing countries like India and China due to its lower operating costs. *Id.* EMS Consulting stated that very few U.S. utilities purchase based on TOC but globally over 22M units have been installed and over 1M amorphous transformers are installed globally per year. *Id.*

EMS Consulting added that, although amorphous transformers exhibited certain performance challenges when they were first commercialized in the 1980s, such as increased transformer size and a tendency to be more brittle, improvements in amorphous properties and manufacturing methods have made them comparable in reliability to GOES transformers. (EMS Consulting, No. 136 at pp. 2–3) EMS Consulting further stated that the high-permeability amorphous products have a higher stacking factor and flux density, which will produce an even smaller and lighter transformer than that assumed by the NOPR. (EMS Consulting, No. 136 at p. 4)

DOE notes that amorphous core transformers are not a new technology. As stated by Metglas and EMS Consulting, installations of amorphous transformers have occurred for decades, beginning in the 1980s. While DOE agrees that amorphous core transformers are less common in the domestic market today than GOES core transformers, DOE disagrees with implication that this is the result of any performance defects precluding amorphous material from being used in place of GOES in distribution transformer cores. As pointed out by EMS consulting, early-stage amorphous core transformers

[66] Qingdao Yunlu Advanced Materials Technology, *Amorphous Ribbon Alloy.* Available at *www.yunluamt.com/product-50-1.html* (last accessed Nov. 8, 2023).

[67] Qingdao Yunlu Advanced Materials Technology, *Amorphous alloy strip, precursor thereof, preparation method of amorphous alloy strip, amorphous alloy iron core and transformer.* China Patent No. CN116162870A. May 26, 2023.

[68] *See Guidebook for POSCO's Amorphous Metal.* Available at Docket No. EERE–2010–BT–STD–0048–0235.

[69] Vacuumschmelze GmbH and Co KG, *Amorphous metal foil and method for producing an amorphous metal foil using a rapid solidification technology,* U.S. Patent No. 11,623,271. Jun. 29, 2023.

faced certain technical challenges, such as increased noise levels and metal shards flaking from the core. However, the development of better manufacturing processes for both amorphous ribbon and amorphous cores has mitigated the impact of these issues.

In DOE's review of the market, it observed multiple major manufacturers of distribution transformers advertising amorphous transformers as reliable, low-loss alternatives to GOES transformers.[70] [71] [72] [73] Manufacturers design these transformers to comply with the same industry standards that apply to GOES units, which include provisions for general mechanical requirements and audible noise limits.[74] During confidential manufacturer interviews, DOE also heard from stakeholders that amorphous transformers have become more comparable to GOES, with some manufacturers often providing specifications to customers for both GOES and amorphous core designs.

DOE also notes that adoption of amorphous metal transformers has significantly increased on a global scale in the past decade. In Canada, for example, over 90 percent of sales for liquid-immersed distribution transformer are estimated to utilize amorphous cores.[75] China and India have similarly exhibited large upticks in amorphous transformer sales.[74] The fact that significant numbers of amorphous distribution transformers have been installed to the electrical grid without any significant reports of failure or apparent design defects, including approximately 600,000 units sold within the U.S.,[76] demonstrates that amorphous transformers can be readily substituted for GOES transformers. Further, some utilities have stated that certain liquid-immersed manufacturers do not even state in bid sheets whether their transformers have an amorphous core or GOES core, indicating that the performance of each transformer is viewed as similar enough to be irrelevant to the manufacturer.[77] For these reasons, DOE has maintained in this final rule that amorphous core transformers can be reasonably interchanged with GOES transformers without impacting performance.

Entergy expressed concern that ferroresonance might be a more prominent issue for amorphous core transformers, especially for lightly loaded transformers or those with protective switching, potentially damaging downstream equipment. (Entergy, No. 114 at p. 3) Entergy stated that an EPRI report indicated that increased noise is a common complaint for amorphous core transformers and that some users indicated that: (1) amorphous cores are more brittle and subject to breaking under strong forces; (2) operating practices may have to change to handle ferroresonance; and (3) lower harmonics passing through the transformer could interact with EV charging stations. Entergy commented that these technical challenges warrant additional research and development prior to the widespread deployment of amorphous technology. *Id.*

Manufacturer literature and public reports [78] widely indicate that technological improvements to the design of amorphous core transformers have largely resolved previous performance issues, such as brittleness of the core. As a result, amorphous core transformers have been deployed worldwide without any significant detriment to performance, as discussed further in Chapter 3 of the TSD, indicating that amorphous transformers can be substituted for GOES transformers in a wide array of applications, including those with sensitive downstream equipment. Regarding ferroresonance concerns specifically, DOE notes that increased instances of ferro resonant conditions have not been linked to use of amorphous metal cores. One study conducted by the Bonneville Power Administration indicated that amorphous core transformers do not significantly increase the probability or severity of ferroresonance incidents.[79] Stakeholder have also previously indicated that they have not experienced any increases in ferroresonance for amorphous core transformers.[80]

MTC commented that amorphous core transformers have approximately 20–25 percent more mass, including all non-core components, due to a lower saturation flux density and stacking factor. (MTC, No. 119 at pp. 11–12) Carte also asserted that amorphous cores require approximately 20 percent more material and the environmental and carbon footprint of producing that material might counter the energy savings. (Carte, No. 140 at p. 1) WEG commented that producing amorphous core transformers would increase the weight of units by 25 percent. (WEG, No. 92 at p. 3)

HVOLT commented that many transformers require stacked core constructions, which is only viable with GOES materials and three-phase construction with wound cores generally increases the transformer size which may not be feasible for applications such as power center transformers. (HVOLT, No. 134 at p. 7) Portland General Electric commented that the larger profile of the amorphous core and windings would require a larger tank, more winding copper/aluminum wire, more oil, and more labor to produce, resulting in higher upfront procurement costs approximately 15–20 percent greater than GOES. (Portland General Electric, No. 130 at p. 3) As an example, Portland General Electric stated that a 25kVA pole-mounted amorphous transformer is roughly the size of 50kVA GOES core transformer. (Portland General Electric, No. 130 at p. 3)

Historically, amorphous transformers have been larger than GOES

[70] Howard, *Howard Amorphous Core Transformers.* Available at *howardtransformer.com/Literature/Amorphous%20Core%20Trans.pdf* (last accessed Oct. 30, 2023).

[71] Hitachi, *Hitachi Amorphous Transformers.* Available at *www.hitachi-ies.co.jp/english/catalog_library/pdf/transformers.pdf* (last accessed Oct. 30, 2023).

[72] Eaton, *Three-phase pad-mounted compartmental type transformer.* Available at *www.eaton.com/content/dam/eaton/products/medium-voltage-power-distribution-control-systems/cooper-power-series-transformers/three-phase-pad-mounted-compartmental-type-transformer-ca202003en.pdf* (last accessed Nov. 15, 2023).

[73] Wilson Power Solutions, *Amorphous Metal Transformers—Myth Buster.* Available at *www.wilsonpowersolutions.co.uk/app/uploads/2017/05/WPS_AMT_Myth_Buster_2018-2.pdf* (last accessed Nov. 30, 2023).

[74] IEEE SA. (2021). IEEE C57.12.00–2021—IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers. Available at *standards.ieee.org/ieee/C57.12.00/6962/* (last accessed Nov. 8, 2021).

[75] Bonneville Power Administration, *Amorphous Core Liquid Immersed Distribution Transformers.* 2020. Available at *www.bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/liquid-immersed-amorphous-core-distribution-transformers-2020-03-31-final.pdf* (last accessed Oct. 30, 2023).

[76] Metglas, *Amorphous Metal Distribution Transformers.* 2016. Available at *metglas.com/wp-content/uploads/2021/06/Metglas-Power-Brochure-Updated.pdf* (last accessed Oct. 30, 2023).

[77] Bonneville Power Administration, *Low-Voltage Liquid Immersed Amorphous Core Distribution Transformers.* 2022. Available at *www.bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/ET-Documents/liquid-immersed-dist-transformers-final-22-0216.pdf* (last accessed Nov. 8, 2023).

[78] Bonneville Power Administration, *Low-Voltage Liquid Immersed Amorphous Core Distribution Transformers.* 2022. Available at *www.bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/ET-Documents/liquid-immersed-dist-transformers-final-22-02-16.pdf* (last accessed Oct. 30, 2023).

[79] Bonneville Power Administration, *Low-Voltage Liquid Immersed Amorphous Core Distribution Transformers.* 2022. Available at *www.bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/ET-Documents/liquid-immersed-dist-transformers-final-22-02-16.pdf* (last accessed Oct. 30, 2023).

[80] *See* Docket No. EERE–2019–BT–STD–0018, Eaton, No. 0055 at p. 10.

transformers. GOES transformers have higher saturation flux density and a higher stacking factor than amorphous transformers, which allows GOES transformers to have a lower volume. However, quality improvements in amorphous ribbon have improved stacking factors. Further, the size of a GOES transformer is largely dependent on the loss performance of GOES being used. See Chapter 5 of the TSD for specific details. To reduce losses in a GOES transformer, manufacturers frequently design larger GOES cores with a reduced saturation flux density, meaning that the size of GOES transformers have increased in an effort to increase the efficiency of GOES transformers.

Eaton submitted data demonstrating that for certain transformer designs, an amorphous transformer weights less at baseline. (Eaton, No. 137 at p. 32) Further, Eaton stated that its data showed that in meeting the proposed efficiency standards, the incremental weight of a more efficient amorphous transformer is only 5.4 percent greater than the base amorphous design and ~1 percent relative to the base GOES design. *Id.* Eaton stated that its data also showed that achieving proposed efficiency levels with a GOES transformer results in a 50 percent weight increase. *Id.*

One study published by the Bonneville Power Administration in 2022 reported the incremental weight increase for baseline GOES transformers and baseline amorphous transformers using data submitted by a distribution transformer manufacturer. Their data indicated that the baseline amorphous transformer was, in many cases, smaller than an equivalent GOES transformer for a number of kVA sizes.[81]

The actual cost and size difference between a GOES core transformer and an amorphous core transformer depends on the actual design of the transformer, the loss performance of the core materials used, the winding material used, and whether manufacturers are trying to meet strict dimensional constraints or simply designing the lowest cost transformer. DOE does not apply blanket cost increases to any transformer that has an amorphous core. Rather, DOE evaluates the change in material costs that would be incurred by both amorphous core and GOES core transformers meeting a range of efficiency levels. In its analysis, DOE does reflect the fact that more efficient transformers typically require more material. This additional material has a cost, which is accounted for in DOE's modeling, is discussed in section IV.C of this document. DOE also considers potential impact on installation costs (*see* section IV.F.2 of this document).

Idaho Falls Power and Fall River stated that amorphous core transformers may have negative environmental impacts when considering the energy gains versus the increased energy usage for manufacturing. (Idaho Falls Power, No. 77 at p. 1; Fall River, No. 83 at p. 1) NAHB commented that 40 percent of electrical steel manufacturing costs are attributed to energy consumption and stated that DOE should consider the impact of high heat in both GOES and amorphous manufacturing. (NAHB, No. 106 at p. 12)

Regarding the energy usage associated with the manufacturing of amorphous cores, DOE notes that relative to GOES, amorphous ribbon production generally has lower temperatures used throughout its production process and a lower transformer core annealing temperature, which would indicate less energy use in manufacturing. Manufacturer literature has reported on the life-cycle assessment of amorphous and GOES cores, which would include the manufacturing, utilization, and end-of-life of the product, and concluded that the environmental impact of high-efficiency amorphous transformers is substantially lower than GOES transformers.[82]

Pugh Consulting questioned whether amorphous metal could be recycled at the end of a transformer's lifetime and suggested DOE consider the costs associated with disposing of and/or recycling all current transformers by 2027. (Pugh Consulting, No. 117 at p. 5) DOE notes that amorphous cores can be recycled at end of life.[83] Further, transformers manufactured before the compliance date for this final rule would be subject to the relevant standards corresponding to their date of manufacture, not the efficiency standards amended in this rule (*i.e.,* all transformers do not need to be disposed of by 2027, as Pugh Consulting suggested). As such, any transformers currently installed, as well as those manufactured before the compliance date for this final rule, would not be required to be disposed of or replaced.

REC commented that amorphous transformers are known to suffer higher failure rates due to increased susceptibility to mechanical stresses, lower short-circuit tolerance, and greater brittleness of the core. (REC, No. 126 at pp. 2–3) APPA commented that amorphous cores are less able to withstand short-circuit faults than GOES transformers and have a lower overload capacity due to lower saturation flux-density. (APPA, No. 103 at p. 12)

APPA and Carte commented that amorphous transformers are subject to metal flakes in the oil which can lead to partial discharging and premature failure. (APPA, No. 103 at pp. 10–11; Carte, No. 140 at pp. 7–8) APPA added that these discharges could require the use of oil monitoring devices for amorphous transformers at an additional cost. (APPA, No. 103 at pp. 10–11) Carte stated that discharging is more likely to occur if amorphous cores are used for higher voltages, which to Carte's understanding they have not been thus far. Carte added that it wasn't sure how amorphous cores were grounded and noted that current core grounding techniques may not be sufficient at higher voltages, additionally risking premature failure. (Carte, No. 140 at pp. 7–8) Regarding increased susceptibility to mechanical stresses, as previously noted, while brittleness of amorphous cores has historically been reported as a performance complication, performance improvements to amorphous ribbon as well as technological developments in the design and bracing of amorphous transformer cores have helped resolve this issue. Additionally, in DOE's review of the market, it observed manufacturer literature advertising construction techniques which reinforce amorphous metal cores and add resilience to mechanical stresses. For example, it has become standard to encase amorphous metal cores in an epoxy resin which stabilizes the core and reduces the likelihood of metal shards forming. Technologies also exist which can be used in tandem with the transformer core to capture shards, ensuring that they do not contaminate the insulation fluid or cause short circuits in the transformer windings. These developments, paired with performance improvements made to the amorphous metal ribbon itself, have significantly reduced the risk of metal flakes from an amorphous core impacting overall transformer performance.

[81] Bonneville Power Administration, *Low-Voltage Liquid Immersed Amorphous Core Distribution Transformers.* 2022. Available at *www.bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/ET-Documents/liquid-immersed-dist-transformers-final-22-02-16*.pdf (last accessed Oct. 30, 2023).

[82] ABB, *Distribution goes green.* Available at *library.e.abb.com/public/f28b7caf32af14e8c1257a25002f2717/40-47%202m221_EN_72dpi.pdf* (last accessed Nov. 9, 2023).

[83] Metglas, Inc. *Recycling of Amorphous Transformer Cores,* 2010. Available at *metglas.com/recycling-amorphous-transformer-cores/* (last accessed Nov. 9, 2023).

Regarding decreased short circuit capacity for amorphous transformers, industry standards set forth the provisions for short-circuit withstand capacity for all transformers, regardless of the transformer core material used.[84] [85] As previously noted, amorphous core transformers are currently being designed and deployed in the field to meet these standards, indicating that they can be designed to withstand the same short circuit capacities as GOES transformers. Similar to the developments which have resolved brittleness issues experienced by early-stage amorphous transformers, technological improvements in the core and coil design for amorphous transformers have the capacity to withstand short circuit events over the years. For example, utilizing foil windings on the secondary coil, rather than rectangular wire or strip, reduces axial forces on the core and winding, reducing mechanical stresses and increasing short circuit capacity. Insulating materials can also be applied around the core to absorb mechanical stresses during operation, reducing the strain experienced by the core itself.[86] As a result, amorphous transformer cores can be reliably built without increased risk of short circuit or premature failure when compared to an equivalent GOES transformer.

APPA stated that DOE should investigate whether the use of amorphous cores would change the gases produced by transformers with the new fluids and steels, the potential impact of using amorphous transformers in areas with extremely hot or cold climates, and the impact of amorphous transformers having a lower overload capacity. (APPA, No. 103 at pp. 16–17)

DOE notes that amorphous core transformers use the same insulation fluids as GOES transformers and APPA did not elaborate as to how the use of an amorphous metal, rather than GOES, in the transformer core would cause the transformer to produce additional or different gases during operation, nor did they elaborate or provide data as to how a change in core material would impact gases produced in a transformer. As such, DOE does not have reason to believe that amorphous core transformers would perform any differently than GOES transformers with regard to gases produced during operation.

Regarding deployment of amorphous transformers in hot or cold climates, as previously noted, amorphous core transformers have been in deployment for several decades and have been deployed worldwide, including areas with extremely hot or cold climates. Further, amorphous core transformers do not inherently have lower overload capacity as detailed in section IV.C.1.d of this document as this is a function of temperature rise and transformer load losses.

APPA further commented that some research indicates that the performance of amorphous transformers degrades over time, with losses likely to become higher than GOES transformers. APPA stated that accounting for those losses would undermine any economic justification for the proposed standards. (APPA, No. 103 at pp. 10–11) DOE notes that both the study cited by APPA and the original 1996 study [87] are referring to degradation in the process of forming an amorphous core from amorphous ribbon (*i.e.* the material destruction factor or build factor), not degradation of the material over time. This kind of degradation is accounted for in the losses for a transformer and is therefore considered in DOE's analysis of both GOES and amorphous core transformers.

Exelon stated its concern about the ability of amorphous core transformers to maintain their efficiency levels over an extended lifetime, calling into question the life-cycle environmental benefit of these new transformers. Exelon commented that studies to address these extended performance concerns are planned but have not yet been executed. (Exelon, No. 95 at p. 3) REC commented that, due to the metallurgical nature of amorphous material, there is a continuous erosion of loss-savings as core material ages and degrades. (REC, No. 126 at p. 3)

PSE commented that amorphous core transformers have lower overload capacity and experience greater mechanical stress during faults due to their rectangular core shape, as opposed round GOES cores. (PSE, No. 98 at p. 13) The SBA expressed concern that amorphous cores may degrade faster and be less capable of sustaining overload conditions than current GOES cores. (SBA, No. 100 at p. 6) REC commented that amorphous transformers have limited load and overload capacity compared to GOES, which will require additional or higher-capacity units to serve the same number of consumers. (REC, No. 126 at p. 2–3) Portland General Electric commented its current design practices allow for peak loads up to 150 percent of the transformer nameplate rating but would need to be revised to accommodate accelerated degradation during overloading for amorphous transformers. (Portland General Electric, No. 130 at p. 3) Cliffs commented that amorphous transformers cannot be loaded as efficiently as GOES cores, which increases likelihood of transformer failure. (Cliffs, No. 105 at p. 11)

Transformer overloading conditions can result in increased mechanical stress and excess heat generation. Therefore, a transformer's capacity to withstand overloading conditions is dependent on its ability to endure mechanical stress and effectively dissipate heat. As previously noted, construction techniques exist to reinforce amorphous metal transformers against mechanical stress, reducing the risk of damage caused by overloading conditions. With regard to an amorphous transformer's ability to shed heat, excess heat is primarily generated through transformer losses. At higher loads, the load losses primarily dictate heat generation due to the quadratic relationship between load losses and transformer loading. Since minimally compliant amorphous transformers are often designed with higher load losses than GOES units, this may lead to the belief that amorphous transformers are less equipped to handle overloading conditions. However, as further discussed in section IV.C.1.d of this document, amorphous transformers do not inherently have higher load losses. Just as GOES transformers can be designed to meet efficiency standards by either reducing no-load or load losses, amorphous transformers can similarly be designed with lower load losses. DOE's modeling includes amorphous core transformers with a range of load losses, thereby maintaining the availability of designs with higher overload capacity. As such, transformer customers will continue to have the option of purchasing transformers with higher or lower overload withstand capacity based on the needs of their application. In absence of overload capacity, customers would likely be

[84] International Electrotechnical Commission, *IEC 60076–5:2006: Power transformers—Part 5: Ability to withstand short circuit.* 2006. Available at *webstore.iec.ch/publication/603.*

[85] IEEE SA. (2021). IEEE C57.164–2021—IEEE Guide for Establishing Short-Circuit Withstand Capabilities of Liquid-Filled Power Transformers, Regulators, and Reactors. 2021. Available at *standards.ieee.org/ieee/C57.164/6804/* (last accessed Nov. 8, 2023).

[86] Wilson Power Solutions, *Amorphous Metal Transformers—Myth Buster.* Available at *www.wilsonpowersolutions.co.uk/app/uploads/2017/05/WPS_AMT_Myth_Buster_2018-2.pdf* (last accessed Oct. 30, 2023).

[87] Y. Okazaki, Loss deterioration in amorphous cores for distribution transformer, Journal of Magnetism and Magnetic Materials 160 (1996) 217–222.

forced to purchase higher kVA ratings than necessary and in doing so risk wasting money, energy, and electrical steel availability.

Although multiple stakeholders expressed concern that the efficiency of amorphous transformers may degrade over time, no stakeholders provided data to demonstrate any such loss of efficiency over time; rather, they only cited studies on the reduction in losses in converting amorphous ribbon into amorphous cores. DOE notes that degradation of transformer performance is often associated with a degradation of transformer insulation, typically due to operation at elevated operating temperatures. As discussed in section IV.C.1.d of this document, amorphous transformers are capable of achieving low load losses, meaning temperature rise would not increase as fast, even at higher-loading conditions. DOE does not have reason to believe that the rated efficiency of an amorphous transformer would degrade over time when compared to an equivalent GOES transformer. Further, manufacturer literature has reported on accelerated aging tests of amorphous transformers and concluded that they saw no degradation of losses in an amorphous core during the transformer life.[88] Therefore, given the lack of data supplied, and given the technological developments which have enabled amorphous transformers to withstand overload conditions and short circuit conditions, DOE did not consider there to be sufficient evidence to model amorphous transformers degrading in performance over time when compared to an equivalent GOES transformer.

Amorphous Market

In the January 2023 NOPR, DOE discussed how amorphous ribbon capacity has increased since the April 2013 Standards Final Rule. 88 FR 1722, 1755. DOE stated that it had identified numerous companies capable of producing amorphous material (of standard am quality or better) and that global amorphous ribbon capacity is much greater than current demand. *Id.* DOE stated that it had learned through manufacturer interviews that amorphous production capacity increased in response to the April 2013 Standards Final Rule, but demand for amorphous did not necessarily correspondingly increase, resulting in excess capacity. DOE discussed how amorphous producers' response to the April 2013 Standards Final Rule demonstrated that, if there was expected to be an increase in market demand for amorphous, capacity would increase to meet that demand. *Id.* Further, DOE also learned through confidential manufacturer interviews conducted in support of the August 2021 Preliminary Analysis and the January 2023 NOPR that recent price increases for GOES have led amorphous to be far more cost competitive. However, despite this increased competitiveness, the industry has not seen an increase in amorphous transformer purchasing, likely due to existing distribution transformer core production equipment being set-up to produce GOES cores and a transition to amorphous cores requiring capital investment. *Id.* Based on these developments, in the January 2023 NOPR, DOE constrained the selection of amorphous alloys under the no-new-standards scenario to better match the current market share of distribution transformers; however, DOE did not apply any constraints to standard am steel purchasing in its evaluation of higher efficiency levels. 88 FR 1722, 1756.

In the January 2023 NOPR, DOE acknowledged that the availability of both GOES and amorphous alloy is a concern for distribution transformers, but expected that suppliers would be able to meet the market demand for amorphous for all TSLs analyzed given the NOPR's 3-year compliance period. 88 FR 1722, 1817. DOE noted that manufacturers should be able to significantly increase supply of amorphous if they know there will be an increase in demand as a result of the proposed energy conservation standards. *Id.* DOE requested comment on this assumption and how supply and demand would change in response to the proposed amended energy conservation standards. *Id.*

In response, HVOLT, Southwest Electric, Cliffs and NRECA expressed concern that there is not sufficient amorphous ribbon capacity currently and capacity will not be able to grow quickly enough to meet the amorphous demand increases expected from the proposed standards. (HVOLT, No. 134 at pp. 5–6; Southwest Electric, No. 87 at p. 3; Cliffs, No. 105 at pp. 10–11; NRECA, No. 98 at p. 3) Cliffs stated that even if all global capacity were used, it would not be enough to support the US market. (Cliffs, No. 105 at pp. 10–11) Cliffs added that DOE incorrectly assumes amorphous production can increase to meet demand without sufficient verification of if that is true. (Cliffs, No. 105 at pp. 10–11)

Hammond commented that only one amorphous producer serves the U.S. market and it cannot scale up in time to meet forecasted demand. (Hammond, No. 142 at p. 2) Hammond added that it is not aware of any efforts outside the U.S. to expand amorphous production to the levels needed to serve the U.S. market. (Hammond, No. 142 at p. 2) DOE notes there is one domestic producer of amorphous steel and one domestic producer of GOES.

Howard commented that the proposed standards will increase GOES demand by 60 percent, or increase amorphous by 600 million pounds, and if all amorphous is domestic, increase domestic amorphous ribbon capacity by 500 percent. (Howard, No. 116 at p. 2) Howard further stated that silicon steel plants typically require 3–4 years and $1–2B to design and build, whereas amorphous would require an additional 15–20 production lines and $1B investment, which isn't achievable in the proposed timeline. (Howard, No. 116 at p. 2) Cliffs commented that amorphous transformers currently make up a small fraction of domestic transformers production and cannot be scaled in the near-term to meet the domestic market. (Cliffs, No. 105 at p. 6)

Prolec GE commented that current and projected capacities of both amorphous metal ribbon and cores will likely remain below the levels required for future demand. (Prolec GE, No. 120 at p. 14) VA, MD, and DE House Representatives commented that the proposed standards will require a rapid expansion of amorphous ribbon capacity which could exacerbate near-term supply chain shortages. (VA, MD, and DE Members of Congress, No. 148 at pp. 1–2)

Several stakeholders expressed concern that there was only a single domestic supplier of amorphous material. Powersmiths commented that the single supplier of amorphous will not be able to expand capacity to meet the needs of the entire distribution transformer market and that it is not acceptable to rely on a single supplier regardless. (Powersmiths, No. 112 at p. 6) TMMA commented that the U.S. manufacturer of amorphous would not be able to serve the entire US transformer market, even with stated capacity expansions, leaving the U.S. reliant on foreign produced amorphous. (TMMA, No. 138 at pp. 3–4) Powersmiths commented that amorphous is not available in the narrower strips required for LVDTs and the 2027 compliance date does not provide sufficient time to put a supply chain in place. (Powersmiths, No. 112 at p. 6) Powersmiths further commented

[88] ABB, *Distribution goes green.* Available at *library.e.abb.com/public/f28b7caf32af14e8c1257a25002f2717/40-47%202m221_EN_72dpi.pdf* (last accessed Nov. 9, 2023).

that hibam is the most viable for LVDT markets and expressed concern that this steel is offered from a single source. (Powersmiths, No. 112 at p. 6)

NAHB expressed concern that the proposed rule would worsen supply and competition concerns. NAHB recommended that, given the limited number of manufacturers for certain products, DOE should work with other Federal agencies to fully review and address the likelihood that this rule will exacerbate anticompetitive supply constraints. (NAHB, No. 106 at pp. 2, 6)

Idaho Falls Power and Fall River stated that relying upon a single domestic supplier of amorphous will create both a de facto monopoly and a bottleneck in an already constrained supply chain. (Idaho Falls Power, No. 77 at p. 1; Fall River, No. 83 at p. 2)

Alliant Energy commented that requiring all distribution transformers to be made from a material with a single domestic suppler representing less than 5 percent of the market will negatively impact transformer production capacity and availability. (Alliant Energy, No. 128 at pp. 2–3) Alliant Energy added that the significant transit times required to source amorphous from foreign nations would exacerbate existing supply chain challenges. (Alliant Energy, No. 128 at pp. 2–3)

In this final rule, DOE notes that it has modified its assumptions to reflect stakeholder feedback suggesting that even if amorphous is the lowest first-cost option, manufacturers may elect to build GOES transformers in order to maintain a more robust supply chain and reduce the impact on existing short to medium-term supply challenges. Specifically, DOE assumed that for liquid-immersed distribution transformers, amorphous adoption will be constrained at all efficiency levels through EL 2, as discussed in section IV.F.3 of this document.

Many stakeholders also commented expressing concern that the use of amorphous metal would increase U.S. reliance on foreign suppliers.

Schneider asserted that given that only one company in Japan and one company in the United States can produce amorphous materials, there is risk of an oligopoly. (Schneider, No. 92 at pp. 9–10) Schneider further stated that there are only two manufacturers that can produce amorphous to meet DOE requirements and the barriers to entry are extremely high. (Schneider, No. 92 at pp. 9–10) Prolec GE commented that manufacturers will be forced to rely on foreign steel suppliers, mainly from China, because the domestic supply of amorphous cannot meet the demand of the U.S. distribution transformer market. (Prolec GE, No. 120 at p. 3) Eaton commented that it would like to have at least three suppliers of amorphous, preferably located in different geographical regions of North America. (Eaton, No. 137 at p. 27)

The Chamber of Commerce commented that requiring transformers to use amorphous cores conflicts with public policy goals by increasing the domestic electricity sector's reliance on inputs from China. (Chamber of Commerce, No. 88 at p. 3) AISI commented that U.S. steel production has a lower carbon intensity that steel made in China. (AISI, No. 115 at p. 2)

EEI commented that the proposed standards will increase the need to rely on foreign sourced products, which will create national security concerns, eliminate American jobs, and increase transit times. (EEI, No. 135 at pp. 29–30) NRECA commented that the proposed standards will increase reliance on foreign nations for amorphous materials in distribution transformers and GOES for power transformers. (NRECA, No. 98 at pp. 3–4) NRECA stated that higher labor costs for amorphous core and a limited domestic capacity for amorphous materials will increase outsourcing of distribution transformer manufacturing, creating a national security risk. (NRECA, No. 98 at pp. 3–4) NRECA added that many utilities are Rural Utilities Service (RUS) borrowers, which prohibits them from purchasing products with foreign-sourced steel. (NRECA, No. 98 at p. 7) Michigan Members of Congress stated that offshoring manufacturing of distribution transformers raises national security concerns. (Michigan Members of Congress, No. 152 at p. 1) Pugh Consulting advised against relying upon a single steel variety and stated that transformer shortages are dangerous given the number of storms, hurricanes, and violent attacks by extremists against distribution transformers. (Pugh Consulting, No. 117 at p. 4) TMMA commented that the proposed standards increase our reliance on international and unfriendly suppliers which is a threat to national security. (TMMA, No. 138 at pp. 2, 4) Howard commented that transformers are vital to national security and given existing shortages, it is vital to maintain both GOES and amorphous as viable options. (Howard, No. 116 at p. 4) AISI commented that if distribution transformers transition to amorphous, that could eliminate domestic GOES, which would be harmful to national security. (AISI, No. 115 at p. 2)

Carte commented that the proposed standards present national security concerns because the timeline is not sufficient for amorphous ribbon capacity to ramp up, which will require additional imports of amorphous. Carte also noted that the domestic supplier's parent company is headquartered in Japan. (Carte, No. 140 at p. 4)

HVOLT expressed concern that the proposed standards requiring manufacturers to rely on a single amorphous supplier based in Japan, whereas they can currently source core steel from multiple GOES suppliers. (HVOLT, No. 134 at pp. 5–6)

Webb expressed concern that shifting towards amorphous cores will place utilities at greater risk and increase U.S. reliance on foreign suppliers. Webb compared this to the recent U.S. semiconductor scarcity and questioned whether the government would similarly address transformer shortages via Federal funding, as was done for semiconductors with the CHIPS and Science Act. (Webb, No. 133 at p. 2)

MTC commented that patent disputes have led Hitachi to consolidate all amorphous production in Japan, making the only global suppliers of amorphous Hitachi and Chinese suppliers. (MTC, No. 119 at p. 20) DOE notes that MTC's comment does not accurately reflect the current state of the market. DOE is aware of amorphous production in the United States today. See Appendix 3A of the TSD for a detailed discussion of the amorphous and GOES markets.

MTC further commented that there is insufficient global production capacity of amorphous to support the U.S. distribution transformer market, even if domestic production capacity were tripled. (MTC, No. 119 at p. 9) MTC additionally commented that lack of domestic steel supply is an issue of national security which should be referred to the Department of Commerce for remedies. (MTC, No. 119 at p. 20)

Exelon commented that the proposed standards could exacerbate supply chain constraints and drive more foreign transformer sourcing, creating new grid reliability challenges and increasing consumer costs. (Exelon, No. 95 at p. 4)

Cliffs commented that relying upon amorphous material represents a national security threat because it is not readily available in the U.S., cannot be manufactured using GOES production equipment, and cannot supply the U.S. grid. (Cliffs, No. 105 at pp. 4–5)

Schneider commented that the production of ferroboron [89] is limited to

[89] Ferroboron is an input in amorphous production. It is produced by a well-known reaction of iron with boron (as boric acid). Both of these minerals are produced in the U.S., although actual ferroboron production typically occurs outside the U.S.

locations outside the U.S., which leads to long-term availability concerns and, because of this, prior evaluations did not consider max-tech. (Schneider, No. 92 at pp. 10–12) Cliffs added that the feedstock to produce amorphous is foreign-sourced, all other major amorphous producers are foreign, and amorphous is more labor intensive, making the U.S. more dependent on foreign supply chains. (Cliffs, No. 105 at p. 7) BCBC and BCGC expressed concern that DOE's proposal could be detrimental to the resiliency of the United States electric grid because amorphous is produced from imported, unproven, and foreign-sourced materials that could compromise both energy and national security in the United States. BCBC and BCGC recommended that DOE adopt policies that increase domestic production of key materials and components to strengthen national security and self-reliance. (BCBC, No. 131 at p. 1; BCGC, No. 132 at p. 1) AISI commented that amorphous cores requires foreign-sourced materials whereas GOES is able to be produced with all stages using domestic manufacturing. (AISI, No. 115 at p. 2) [90]

DOE notes that the current status quo for the distribution transformer market involves a single domestic GOES manufacturer and multiple global GOES suppliers, with any imported GOES subject to tariffs. As a result, transformer manufacturers who produce transformer cores domestically are largely reliant on the single domestic GOES supplier, given that using GOES from any other supplier requires paying a tariff. For amorphous, there is similarly a single domestic amorphous manufacturer and multiple global suppliers. Meeting higher-efficiency standards with amorphous would result in domestic transformer manufacturers who produce transformer cores domestically being largely reliant on the single domestic amorphous supplier, given that using amorphous from any other supplier requires paying a tariff. This is similar to the current market structure for GOES. Therefore, DOE disagrees that a distribution transformer supply chain with substantial amorphous cores is inherently more of a national security risk than the existing GOES-based supply chain. The current distribution transformer supply chain, as well as how the market is expected to respond to amended standards, is further discussed in section IV.A.5 of this document.

DOE considers the effect of DT standards on the domestic supply chain in setting standards. However, DOE notes that a distribution transformer market served by 100 percent domestically produced electrical steel does not exist today. One transformer manufacturer noted that having only a single-domestic supplier of GOES represents a considerable supply risk. They further stated that developing the workforce skills and manufacturing capabilities to leverage both GOES and amorphous will reduce their electrical steel supply risk, provided development of that capability does not disrupt existing product output.[91] Several stakeholders expressed concern that too rapid of a transition to amorphous cores could worsen near-term supply chains and recommended DOE wait for capacity to increase prior to implementing any amended efficiency standards.

ABB stated that DOE should ensure that there is a sufficient and competitive supply of GOES and amorphous before requiring significantly higher energy conservation standards. (ABB, No. 107 at pp. 2–3) ABB went on to state that the transformer industry is already experiencing an insufficient domestic supply of GOES and expressed concern that the same challenges would be faced with amorphous cores. (ABB, No. 107 at pp. 2–3) NWPPA commented that manufacturers struggle to source the high performing GOES required to meet current standards and the proposed standards would require an even scarcer variety of steel for very small gains in efficiency. (NWPPA, No. 104 at p. 1) NRECA commented that DOE's proposal will not expand the market for distribution transformers because most current production using GOES will not be able to meet the proposed standards. (NRECA, No. 98 at p. 2)

WEG commented that amorphous cores will be the most cost effective way to meet standards, but the supply chain for amorphous material is not prepared to sustain the market or support the electrical grid. (WEG, No. 92 at pp. 2–3) WEG stated that U.S. manufacturers would need 200,000 tons of amorphous to meet the proposed standards, which would be 100 percent of global amorphous ribbon capacity just to support the U.S. (WEG, No. 92 at pp. 2–3) WEG additionally commented that using amorphous cores will require years of technical development and industry won't be able to use GOES in the meantime. (WEG, No. 92 at pp. 2–3)

Cliffs commented that requiring amorphous cores would make the transformer supply chain less secure and require considerable investment from transformer manufacturers at a time of existing supply chain and labor challenges. (Cliffs, No. 105 at p. 6) Cliffs commented that only a single domestic manufacturer has the technical know-how to produce amorphous ribbon and even if that manufacturer licensed the technology, if efficiency standards require amorphous cores, the manufacturer will effectively have a monopoly that will lead to increased prices. (Cliffs, No. 105 at pp. 15–16)

UAW commented that the proposed standards may upend the distribution transformer market by relying upon steel which is in short supply and more expensive than the GOES currently used. (UAW, No. 90 at p. 3)

Webb recommended that DOE confirm whether amorphous ribbon capacity can be made available to meet both current GOES demand and increased future demand due to distributed energy resource deployment. (Webb, No. 133 at p. 2)

Metglas commented that continued expansion of amorphous production by other producers demonstrates that there are no IP-related impediments to expanding use of amorphous transformers. (Metglas, No. 125 at pp. 3–4) Metglas commented that grades of GOES exist that can meet the proposed DOE standards and suggested that GOES will continue to serve a significant portion of U.S. demand for distribution transformers, even in the presence of amended standards. (Metglas, No. 125 at pp. 3–4) Metglas went on to state that the proposed standards will encourage competition for transformer core steel and help solidify a majority domestic supply of transformer core steel. (Metglas, No. 125 at pp. 3–4)

The current domestic demand for electrical steel used in distribution transformers is estimated to be approximately 225,000 metric tons, which is approximately equal to the global capacity for amorphous material. The response to the April 2013 Standards Final Rule demonstrated that amorphous material manufacturers are willing and capable of adding capacity in response to increased demand (See Chapter 3A of the TSD). Metglas commented that between 2015 and 2018, production of amorphous alloy in China increased by 50,000 metric tons. (Metglas, No. 11 at pp. 3–4). Eaton commented that between 2013 and

[90] U.S. Department of Commerce, *The Effect of Imports of Transformers and Transformer Components on the National Security.* (2020). Available at *www.bis.doc.gov/index.php/documents/section-232-investigations/2790-redacted-goes-report-20210723-ab-redacted/file.*

[91] Markham, I., *ERMCO CEO: For an Effective Outcome, Focus on Inputs,* The Wall Street Journal, Jan. 5, 2024. Available online at: *https://deloitte.wsj.com/riskandcompliance/ermco-ceo-for-an-effective-outcome-focus-on-inputs-3ecfbeff.*

2019, three additional companies entered the amorphous market with similar product widths to the U.S. domestic producer of amorphous (Eaton, No. 12 at p. 7)

If amended standards created an assured demand for amorphous material, it can be reasonably expected that amorphous ribbon capacity would increase to meet the demands of the U.S. distribution transformer market. Given expected demand for amorphous ribbon, there are no technical constraints preventing amorphous ribbon capacity from increasing, eventually; however, there is uncertainty as to what time frame that capacity would be sufficient to meet the demand created by amended efficiency standards. Metglas commented that it currently has an installed capacity of 45,000 metric tons available domestically and stated that it can bring an additional 75,000 metric tons of production online in less than 37 months, bringing total domestic capacity to 120,000 metric tons. Further, Metglas stated that it is willing to invest beyond current facility location constraints to meet customer demand. (Metglas, No. 125 at p. 8) In addition to statements from the current domestic amorphous supplier and demonstrations of capacity additions in other countries, recent patent filings from several major steel producers indicate that the production of amorphous alloy is an area of active technological innovation.[92] [93] [94] [95]

If all distribution transformers had to transition to amorphous cores immediately, stakeholders stated that the capacity and core-construction infrastructure would not exist and there would be considerable price increases which would very likely worsen supply chains and have negative cost impacts for consumers, at least until supply could catch up with demand. However, comments from stakeholders indicate that longer transition times could allow distribution transformer manufacturers to more gradually transition to amorphous cores, mitigating supply chain concerns. DOE received several comments from stakeholders as to what they believe would be a reasonable timeframe and scope to allow for a gradual transition to higher-efficiency without significantly impacting near term pricing. These comments are discussed in section IV.C.2.a of this document.

As discussed, for efficiency levels up through EL2 for liquid-immersed distribution transformers, both amorphous and GOES transformers are anticipated to be able to compete on first cost. While stakeholders expressed concern that amorphous would not be able to scale up sufficiently to serve the entire distribution transformer market, DOE estimates that approximately 48,000 metric tons of amorphous will be used to meet the amended standards for liquid-immersed distribution transformers. While this is a considerable increase from the amount of amorphous used in distribution transformer cores today, it is approximately equal to the current stated amorphous capacity (of approximately 45,000 metric tons). Meaning, even if the amorphous core market were to be entirely served by domestic manufacturing, no additional amorphous manufacturers were to enter the market, and the current domestic manufacturer were to add no production capacity, amorphous capacity would still be approximately sufficient to serve the distribution transformer market.

b. Grain-Oriented Electrical Steel Market and Technology

GOES is a variety of electrical steel that is processed with tight control over its crystal orientation such that its magnetic flux density is increased in the direction of the grain orientation. The single-directional flow is well suited for distribution transformer applications and GOES is the dominant technology in the manufacturing of distribution transformer cores. GOES is produced in a variety of thicknesses and with a variety of loss characteristics and magnetic saturation levels. In certain cases, steel manufacturers may further enhance the performance of electrical steel by introducing local strain on the surface of the steel through a process known as domain refinement, such that core losses are reduced. This can be done via several methods, some of which survive the distribution transformer core annealing process.

In the January 2023 NOPR, DOE maintained the four subcategories of GOES that it had identified in the August 2021 Preliminary Analysis as possible technology options. 87 FR 1722. 1756. These technology options and their DOE abbreviations are shown in Table IV.5.

Table IV.5 GOES Steel Technology Options

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

DOE noted in the January 2023 NOPR that for high-permeability steels, steel manufacturers have largely adopted a naming convention that includes the steel's thickness, a brand-specific designator, followed by the guaranteed core loss of that steel in W/kg at 1.7 Tesla (T) and 50 Hz. *Id.* Power in the U.S. is delivered at 60 Hz and the flux

[92] VAC, *Amorphous Material—VITROVAC,* (Last Accessed 12/21/2023), Available online at: *https://vacuumschmelze.com/products/soft-magnetic-materials-and-stamped-parts/amorphous-material-vitrovac.*

[93] Hartman, T., *Amorphous Metal Foil and Method for Producing an Amorphous Metal Foil Using a Rapid Solidification Technology,* U.S. 0201914, 2023.

[94] Guidebook for POSCO's amorphous metal, Docket No. EERE–2010–BT–STD–0048–0235.

[95] Nippon Steel Corp, *Fe-Based Amorphous Alloy Having Excellent Soft Magnetic Characteristics and Processability, Fe-Based Amorphous Alloy Thin Strip Having Excellent Soft Magnetic Characteristics and Processability, Wound Core, Stacked Core and Rotary Electric Machine,* JP20231017731A, 2023.

density can vary based on distribution transformer design, therefore the core losses reported in the steel name are not identical to their performance in the distribution transformer. However, the naming convention is generally a good indicator of the relative performance of different steels.

In the January 2023 NOPR, DOE discussed how different grades of GOES, and in particular hib and dr GOES, are typically marketed as suitable for use in either power or distribution transformers. *Id.* However, DOE also noted that power transformers tend to have priority over distribution transformers and generally receive the highest performing grades of GOES, as stated by stakeholders in public comment. (Schneider, No. 49 at p. 14; Cliffs, No. 57 at p. 1) The larger volume of the liquid-immersed distribution transformer market similarly tends to be served before the dry-type distribution transformer market. *Id.*

In response to the August 2021 Preliminary Analysis TSD, DOE received comment from stakeholders that the GOES steel supply had become more constrained in recent years. Stakeholders commented that certain grades of steel are becoming more difficult to acquire and costs have increased for all grades of steel. 87 FR 1722, 1756. In the January 2023 NOPR, DOE noted that the combined effect of general commodity related supply chain issues and competition from the EV market likely contributed to these recent supply issues and cost increases. *Id.* In response to stakeholder feedback, DOE proposed screening out some of the highest performing grades of GOES, where steel manufacturers are not able to mass produce GOES of similar quality. *Id.* In this final rule, DOE continued to screen out these steel grades, as discussed in section IV.B of this document. Further, DOE also updated all material costs in this final rule to account for recent trends in market prices, as discussed in section IV.C.2 of this document.

In response to the January 2023 NOPR, DOE received additional comments regarding the supply and availability of GOES.

NEMA commented that GOES with better performance than M3 is typically not available from domestic suppliers. (NEMA, No. 141 at p. 14) WEG commented that there are global shortages of high-grade GOES today. (WEG, No. 92 at p. 1) Prolec GE commented that GOES supplies have been constrained by worldwide increase in demand for GOES coupled with shifting production capacity to non-oriented electrical steel (NOES). (Prolec GE, No. 120 at p. 10) Howard commented that the GOES market has been severely impacted by NOES demand spikes. (Howard, No. 116 at p. 23) Metglas commented that there is currently a shortage of GOES due to a combination of factors, including competition from NOES and thinner gauge requirements for EVs reducing steel mill output capacity. (Metglas, No. 125 at p. 5)

MTC provided US import and consumption data for GOES and commented that U.S. consumption of GOES for distribution transformers is approximately 175K MT. (MTC, No. 119 at p. 2) MTC additionally commented that Cliffs is not currently able to meet demand requirements for GOES in the U.S. (MTC, No. 119 at p. 2) MTC added that lack of a secure domestic steel supply is an issue of national security which should be referred to the Department of Commerce for remedies. (MTC, No. 119 at p. 20) Efficiency Advocates commented that the current domestic GOES supply is insufficient to meet market demands and additional suppliers of GOES are unlikely to form due to long lead times and significant capital requirements. Efficiency Advocates further commented that higher grades of GOES are not available in large quantities domestically. (Efficiency Advocates, No. 121 at pp. 2–3)

Pugh Consulting commented that the single supplier of GOES has not indicated that they will increase production to meet demand and it is unclear whether a new manufacturer could obtain a Title V Clean Air Act permit. (Pugh Consulting, No. 117 at p. 3) DOE notes that Title V of the Clean Air Act requires facilities that are major sources of air pollutants to obtain operating permits, which specify permissible limits of pollutant emissions. However, Title V permitting for steel manufacturers is beyond the scope of this rulemaking.

Hammond commented that it expects the market to provide an adequate supply of both NOES and GOES for the foreseeable future. (Hammond, No. 142 at p. 2) Schneider commented that the supply and demand of GOES is well balanced today, GOES capacity will gradually increase over time, and they do not expect manufacturers to shift production of GOES to NOES because steel manufacturers recognize the role of GOES. (Schneider, No. 101 at p. 9)

Cliffs commented that it recently invested $40M to expand domestic electrical steel production (both GOES and NOES) and aims to invest more in the near future to keep up with demand. (Cliffs, No. 105 at p. 15)

NAHB commented that GOES is harder and more costly to produce than NOES because it requires additional processing steps. NAHB pointed out that a new domestic electrical steel facility, which opened in 2023, elected to produce NOES rather than GOES, which may indicate other domestic steel producers are unlikely to add GOES production lines. (NAHB, No. 106 at pp. 9–10)

Stakeholder comments submitted in response to the January 2023 NOPR further confirm that the current GOES market is experiencing supply constraints, inhibiting the ability of manufacturers to obtain the full range of core steel grades. DOE notes that this appears to be especially true for the domestic steel market, which stakeholders have stated does not have a sufficient quantity of low-loss steels to serve the needs of U.S. distribution transformer market.[96] Although the sole domestic producer of GOES is capable of producing a full range of M-grades and some hi-b steels, the supply of dr steels is more constrained and there is currently no domestic production of pdr GOES. Further, as previously noted, distribution transformer manufacturers compete for GOES with power transformer manufacturers, with many of the highest performing grades dedicated to power transformer production over distribution transformer production.

This leaves a limited supply of the lowest-loss grades of GOES for distribution transformer manufacturers. Since 2018, all raw imported electrical steel has also been subject to a 25 percent *ad valorem* tariff.[97] Therefore, manufacturers are forced to choose between sourcing from the single domestic provider of GOES or paying more for imported product. The result of these myriad factors is a strained GOES supply for distribution transformer production.

DOE also received comments regarding how the proposed standards might impact the GOES market.

Pugh Consulting suggested DOE should explore options to incentivize the domestic production of amorphous and GOES steel for distribution transformers, such as funding authorized by Congress, tax credits, and use of the Defense Production Act. (Pugh Consulting, No. 117 at p. 7) DOE notes that this final rule pertains only to energy conservation standards for

[96] *See also* Department of Commerce investigation into imports of laminations and wound cores for incorporation into transformers. Docket No. BIS–2020–0015. Available at *www.regulations.gov/docket/BIS-2020-0015*.

[97] *See* 83 FR 11625.

distribution transformers, and any efforts to amend other Federal regulatory programs and policies are beyond the scope of this rulemaking. However, separate agency actions may promote production of domestic amorphous and GOES including the Advanced Energy Project Credit (48C) Program in partnership with the Department of the Treasury and the Internal Revenue Service.[98]

CARES commented that there is insufficient supply of either GOES or amorphous to meet the demand required by the proposed standards. (CARES, No. 99 at p. 3)

Cliffs commented that the proposed standards are contrary to established Federal policies that have designated GOES a critical product essential to U.S. national security interests. (Cliffs, No. 105 at pp. 2, 5–6) Specifically, Cliffs commented that the proposed standards are counter to the 232 report which concluded that maintaining domestic GOES capacity is crucial to national security and that domestic steel producers must have viable markets beyond solely the defense industry. (Cliffs, No. 105 at pp. 4–5) Cliffs stated that the proposed standards would negate any benefits currently being realized by the 25 percent 232 tariffs, which undermines the entire purpose of the tariffs. (Cliffs, No. 105 at pp. 3–5)

Cliffs further commented that the majority of domestic GOES is manufactured for use in distribution transformers and the NOPR makes production of both GOES and NOES economically untenable, risking 1500 jobs and undermining the supply chain for transformers, electric motors, and other industries. (Cliffs, No. 105 at p. 6) Cliffs additionally noted that: (1) GOES is needed for bulk power infrastructure, (2) several Federal reports have recommended establishing a stockpile of domestic GOES, and (3) the Cybersecurity and Infrastructure Security Agency has stated that large-power transformers are overly reliant on foreign imports, all of which further demonstrate the importance of domestic GOES manufacturing for national security. (Cliffs, No. 105 at pp. 7–8) DOE notes that large-power transformers are not subject to energy conservation standards.

Several stakeholders suggested that producers of electrical steel would discontinue production of GOES without demand for distribution transformers, eliminating the domestic supply of electrical steel and causing layoffs of approximately 1500 employees. (UAW, No. 90 at p. 1; UAW Locals, No. 91 at p. 1; BCBC, No. 131 at p. 1; BCGC, No. 132 at p. 1) Stakeholders stated that this would eliminate the supply of electrical steel for other industries, such as EV motors, and make the U.S. entirely reliant on foreign entities to support the grid. *Id.* BCBC and BCGC added that the Butler Works electrical steel plant supports Butler County and any loss will have an exponential and devastating impact well beyond the plant itself. (BCBC, No. 131 at p. 1; BCGC, No. 132 at p. 1) UAW Locals and BCBC and BCGC recommended that DOE either withdraw the NOPR or proceed with an efficiency standard that ensures continued use of GOES in distribution transformers. (UAW Locals, No. 91 at p. 2; BCBC, No. 131 at p. 1; BCGC, No. 132 at p. 1)

A number of stakeholders similarly submitted comments expressing concern that the proposed rulemaking would weaken domestic supply chains and jeopardize U.S. jobs by making the U.S. more reliant on foreign amorphous suppliers and suggested DOE should ensure GOES can continue to be used in distribution transformers. (Thomas, No. 155 at p. 1–2; Pennsylvania AFL–CIO, No. 156 at p. 1–2; BCCC, No. 158 at p. 1–2; Renick Brothers Co., No. 160 at p. 1; Snyder Companies, No. 161 at p. 1; Nelson, No. 157 at p. 1)

Other stakeholders similarly expressed concern that the proposed standards may lead the single domestic producer of GOES to either reduce or discontinue production, which could hurt transformer supply chains and make transformer manufacturers more reliant on foreign steel importers. (Michigan Members of Congress, No. 152 at p. 1; HVOLT, No. 134 at p. 7; AISI, No. 115 at pp. 2–3; Alliant Energy, No. 128 at p. 3; Kansas Congress Member, No. 143 at p. 1; Entergy, No. 114 at p. 2)

Eaton commented that DOE should consider the possibility of domestic GOES manufacturing disappearing in response to standards, leaving other critical resources like power transformers without a stable supply chain. (Eaton, No. 137 at p. 26) TMMA commented that the domestic GOES producer is not planning to invest in producing premium GOES grades and, therefore, U.S. transformer manufacturers will need to use foreign-produced GOES which isn't available in sufficient capacity to support the U.S. transformer market. (TMMA, No. 138 at pp. 3–4) MTC commented that the proposed standards will increase the cost of GOES production, potentially jeopardizing refurbishment, resilience, and upgrading of the grid. (MTC, No. 119 at p. 19) NEMA commented that the administration has sought to increase domestic manufacturing and this rule creates a dangerous imbalance of core steel supply. (NEMA, No. 141 at p. 2) NAHB commented that declining imports of both finished transformers and GOES in recent years, paired with a lack of domestic competition for GOES production, have exacerbated the transformer crisis and expressed concern that the NOPR will worsen these issues. (NAHB, No. 106 at pp. 6–8)

In the January 2023 NOPR, DOE discussed how GOES production can be shifted to NOES production at only a modest cost. 88 FR 1722, 1767. Stakeholders have commented that this transition is already occurring and has partially contributed to the GOES shortages experienced by the transformer industry. *Id.* The shift towards NOES production is largely driven by electrification trends and increased production of EV motors, creating an assured demand for NOES well into the future. As such, manufacturers of GOES in the current market may have the option of converting GOES production lines to NOES capacity in the event that demand for GOES decreases.

While Cliffs indicated in its comment that GOES production is used to support NOES production, DOE notes that in 2023 an additional domestic NOES production facility opened without GOES production.[99] This indicates that a NOES production facility is a reasonable investment on its own.

DOE also notes that other markets for GOES exist. For example, the power transformer market also acts as an end-use for domestically produced GOES. Although this market is smaller than the distribution transformer market by volume, with total demand for medium and large power transformers estimated to be over 2,700 units per year, individual units can weigh several hundred tons, contributing a significant source of demand for GOES. 86 FR 64606, 64662. Increased electrification likely means that the demand for large-power transformers, and therefore demand for GOES in large-power transformers, will continue to increase. Given the assured demand for GOES from the power transformer industry and the available option to convert capacity to NOES, along with the fact that a second domestic NOES production facility recently began

[98] *See https://www.energy.gov/infrastructure/qualifying-advanced-energy-project-credit-48c-program.*

[99] U.S. Steel, *Big River Steel Overview.* Available at *www.ussteel.com/bigriversteeloverview* (last accessed Nov. 8, 2023).

production, it is unlikely that domestic electrical steel production would entirely disappear because of amended efficiency standards.

However, lead times for distribution transformers have significantly increased in recent years and could be exacerbated by a wholesale transition to amorphous cores at this time. Further, the vast majority of domestic GOES production is used in distribution transformers, and while alternative uses for that capital equipment may exist, preemptive conversion of that capital in anticipation of disappearing demand could exacerbate near-term transformer shortages. In an effort to minimize this risk, DOE has evaluated an additional TSL in which certain segments of the distribution transformer market remain at efficiency levels that can be met cost-competitively via GOES, as discussed in section V.A. DOE has also, in response to stakeholder feedback, modified its consumer purchasing behavior model to reflect the emphasis that both manufacturers and utilities are placing on lead time, wherein consumers continue to purchase a GOES transformer even if an amorphous transformer is lower cost up to a certain efficiency level, as discussed in section IV.F.3 of this document.

Finally, the standards finalized in this final rule include several equipment classes, representing considerable volume of core material, where GOES is expected to remain cost-competitive. DOE estimates the volume of core steel used in the equipment classes where GOES is expected to remain cost-competitive to be over ~146,000 metric tons for liquid-immersed distribution transformers, only a 21 percent reduction from the ~185,000 metric tons for liquid-immersed distribution transformers assumed in the no-new standards case. DOE also understands that manufacturers prefer to continue using existing GOES core production equipment, rather than replace GOES core production equipment with amorphous core production equipment., Accordingly, DOE expects that, for those classes where GOES remains cost-competitive, manufacturers will continue purchasing GOES steel, and will do so in quantities approximately equal to the existing domestic GOES market. Therefore, DOE does not expect a significant decrease in domestic GOES sales as a result of this rule.

DOE notes that core production equipment is somewhat flexible to manufacturer a variety of core sizes. As such, if an existing piece of GOES core production equipment manufactures cores for 75 kVA, 100 kVA and 167 kVA, as an example, manufacturers can meet efficiency standards by shifting that equipment to increase 75 kVA and 100 kVA GOES cores and adding a new amorphous core production machinery to manufacture 167 kVA transformers. The resulting set-up results in an increase in total transformer core production capacity as the amorphous line is invested in as an additive equipment line, as opposed to replacing existing GOES production equipment.

c. Transformer Core Production Dynamics

In the January 2023 NOPR, DOE discussed how transformer manufacturers have the option of either making or purchasing transformer cores, with some manufacturers choosing to do a mix of the two. 88 FR 1722, 1757. DOE further stated that transformer manufacturers also have the choice of producing cores domestically or producing them in a foreign country and importing them into the U.S. This creates three unique pathways for producing distribution transformers: (1) producing both the distribution transformer core and finished transformer domestically; (2) producing the distribution transformer core and finished transformer in a foreign country and importing into the United States; (3) purchasing distribution transformer cores and producing only the finished transformer domestically. *Id.*

DOE discussed how each of these unique sourcing pathways has their own advantages and disadvantages. Manufacturers who produce cores domestically may have the most control over their lead times and supply chains but may be more limited in selection of steel grades as a result of tariffs on foreign-produced GOES and only having access to one domestic manufacturer. Producing cores in a foreign country and importing into the U.S., on the other hand, allows for the same in-house production with access to the entire global market for GOES without the tariff on electrical steel, but provides less supply chain control and may lead to longer lead times. Finally, purchasing finished cores directly allows manufacturers to avoid investing in the labor and capital equipment required for core production, but provides the least control over delivery lead times and often will result in a higher cost per pound of steel when compared to manufacturers producing their own cores. *Id.*

In the January 2023 NOPR, DOE assumed that, in the presence of amended standards, manufacturers would maintain the same core production practices that they currently employ. 88 FR 1722, 1757–1758. For manufacturers that produce their own cores, this would mean investing in their in-house production processes and purchasing additional capital equipment, as required, in order to produce cores from higher grades of steel. For manufacturers that purchase finished cores, this would mean switching from purchasing cores of one steel grade to purchasing cores of a higher steel grade. Further, DOE stated that it did not view any one of these core and transformer production processes as becoming more advantaged or disadvantaged through amended standards and requested comment on whether the proposed standards would alter any of the current production pathways. *Id.*

A Kansas Congress Member recommended that DOE consider the immediate economic impacts that new standards may have on domestic steel and transformer manufacturers, energy providers, and developers. (Kansas Congress Member, No. 143 at p. 1)

Schneider commented that the 2016 standards caused many companies to shift from slitting steels to outsourcing core production. Schneider stated the proposed standards could potentially impact U.S. labor by further pushing core assembly to foreign suppliers. (Schneider, No. 92 at p. 10)

NEMA commented that GOES cores are both manufactured in-house and purchased from third party sources, but stated that distribution transformer manufacturers do not have the ability to produce amorphous cores internally. (NEMA, No. 141 at pp. 2–3) NEMA stated that the proposed standards would force manufacturers to either purchase transformer cores, weakening the supply chain, or make substantial investments in new capital. *Id.* NEMA added that there is only a single domestic company manufacturing amorphous cores and due to large capital costs, new capacity is unlikely to increase in the foreseeable future without Federal funding to expand domestic amorphous core manufacturing. (NEMA, No. 141 at pp. 2–3) NEMA further stated that the capital expenses needed for amorphous cores are likely to increase outsourcing of core manufacturing, potentially shifting jobs overseas and giving a monopolistic hold to the sole domestic manufacturer of amorphous cores. (NEMA, No. 141 at pp. 16–17) DOE notes that multiple domestic manufacturers have in-house amorphous core production capacity, although typically in substantially lesser volume than GOES core production. Substantial capital investments would be needed to add amorphous core production capacity. DOE has accounted for these capital investments in its MIA as discussed in section IV.J.

Howard commented that any regulation favoring GOES or amorphous will result in single source availability of core steel and encourage core offshoring, as tariffs have already done. (Howard, No. 116 at p. 18)

MTC expressed concern that the more labor intensive production process for amorphous metal cores will push core production outside the U.S. (MTC, No. 119 at p. 19)

The SBA commented that DOE must consider statutory factors including ''the impact of any lessening of competition.'' The SBA went on to state that there is only one domestic manufacturer of transformer cores which is already unable to keep up with demand. (SBA, No. 100 at p. 5) DOE notes that there are multiple domestic producers of distribution transformers, many of whom also produce cores domestically as detailed in Chapter 3 of the TSD.

Alliant Energy commented that it prefers to procure transformers domestically to protect grid security, expressing concern that there is currently only one U.S. producer of amorphous core steel with limited capacity. (Alliant Energy, No. 128 at pp. 2–3) DOE notes that most distribution transformers are produced domestically; however, depending on distribution transformer core production dynamics, the core steel in those products may or may not be produced domestically. As discussed in section IV.A.4.a of this document, both the amorphous and GOES market have one domestic producer and multiple global producers with capacity largely reflecting current demand.

Metglas stated that it does not control amorphous core costs, but an increased number of amorphous core makers should promote competition and drive down costs. (Metglas, No. 125 at p. 6)

DOE notes that while some stakeholders speculated efficiency standards where amorphous cores were most cost competitive would change core production dynamics, manufacturer's early responses in anticipation of a final rule suggest that a similar core production dynamic will exist (see chapter 3 of the TSD for additional details). DOE notes that distribution transformer manufacturers have already invested in additive facilities to produce amorphous cores domestically (and are already producing them).[100] DOE also notes that core manufactures have stated that they are planning on adding new facilities to produce amorphous cores in Canada and sell them to transformer manufacturers.[101]

DOE additionally notes that the adopted standards will maintain cost-competitive market segments for both GOES and amorphous. Therefore, manufacturers producing their own cores today can continue to utilize existing core production equipment.

Further, distribution transformer manufacturers are already investing in manufacturing expansions to support increased capacity demands on the electrical grid. In the past several years, manufacturers across the distribution transformer market have announced expansions of current capacity and intentions expand (some of these announced capacity expansions are discussed in chapter 3 of the TSD). As such, even without amended standards, manufacturers currently producing their own cores would need to invest in additional core production equipment to support these capacity additions or make alternative core procurement decisions. Therefore, manufacturers will have the option to add amorphous production capacity as part of these planned expansions in an additive fashion to meet increased demand, rather than adding amorphous production capacity to replace existing GOES capacity. This will further reduce the capital expenditures that manufacturers would be required to incur to meet amended standards, mitigating the risk that outsourcing of cores will increase.

Therefore, for the reasons discussed, DOE continued to assume in this final rule that all three core and transformer production pathways will remain viable options in the presence of amended standards, with manufacturers expected to maintain their current production practices.

5. Distribution Transformer Supply Chain

The distribution transformer market is divided into three segments—liquid-immersed, low-voltage dry-type, and medium-voltage dry-type—each of which has unique market dynamics and production practices. In recent years, the distribution transformer market has experienced significant supply chain challenges across all three segments of the market that have largely been attributed to demand for distribution transformers, along with other electric grid related equipment, increasing substantially. As result, lead times for transformers have increased and utility companies' transformer inventories have been reduced.

DOE notes that current shortages in the distribution transformer market are unrelated to efficiency standards. Current distribution transformer shortages are instead related to a significant increase in demand for many electric grid related products, which includes not only distribution transformers but many other products associated with expansion of the electrical grid not subject to any efficiency standards. Distribution transformer manufacturers have reported record production, in terms of number of shipments, but still noted that demand has grown even faster.[102]

PSE commented that lead times for distribution voltage regulators are even longer than for distribution transformers and this is unlikely to improve if electrical steelmakers are forced to shift to amorphous. (PSE, No. 98 at p. 11) DOE notes that voltage regulators are not subject to energy conservation standards but serve as an example of how product shortages are associated with many electric grid related products.

While numerous expansions of distribution transformer production plants have been announced, as discussed in Chapter 3 of the TSD, it takes time for those capacity expansions to come online. DOE notes that its proposed standards have considered the interaction between capacity expansions and conversion investment costs to meet the amended efficiency standards. Specifically, DOE adopted standards wherein manufacturers can choose to comply using either GOES or amorphous for the vast majority of shipments and significantly limited the shipments that can realistically only be met with amorphous cores. Stakeholders have noted that the ability to leverage both GOES and amorphous will reduce their electrical steel supply risk, provided development of that capability does not disrupt existing product output.[103]

[100] Howard, T. *Howard Industries cuts ribbon on Quitman plant,* The Meridian Star, 2023. Available at *www.meridianstar.com/news/howard-industries-cuts-ribbon-on-quitman-plant/article_022f5248-7a7e-11ee-91f9-873895c690d6.html.*

[101] Worthington Steel, *Investor Day.* Transcript. Available at *s201.q4cdn.com/849745219/files/doc_events/2023/Oct/17/worthington-steel-investor-day-transcript-final-10-11-23.pdf.*

[102] TB&P, *Electric Coops CEO wrestles with ever-evolving factors to maintain reliability, affordability,* Jan. 15, 2023. Available online at: *https://talkbusiness.net/2023/01/electric-coops-ceo-wrestles-with-ever-evolving-factors-to-maintain-reliability-affordability/.*

[103] Markham, I., *ERMCO CEO: For an Effective Outcome, Focus on Inputs,* The Wall Street Journal, Jan. 5, 2024. Available online at: *https://deloitte.wsj.com/riskandcompliance/ermco-ceo-for-an-effective-outcome-focus-on-inputs-3ecfbeff.*

In response to the January 2023 NOPR, DOE received comments on the current state of the distribution transformer market.

A variety of utility companies, trade associations, and other stakeholders commented that increased demand has led to nationwide distribution transformer shortages, with utility reserve stocks significantly reduced and lead times on the scale of 2 to 4 years. (APPA, No. 103 at p. 4; TMMA, No. 138 at p. 2; Indiana Electric Co-Ops, No. 81 at p. 1; Fall River, No. 83 at p. 2; Central Lincoln, No. 85 at p. 1; NRECA, No. 98 at p. 2; EEI, No. 135 at pp. 6–7, 9–10; Pugh Consulting, No. 117 at p. 3; NWPPA, No. 104 at p. 1–2; Entergy, No. 114 at p. 2; REC, No. 126 at p. 1–2; Xcel Energy, No. 127 at p. 1; Alliant Energy, No. 128 at p. 2; NMHC & NAA, No. 97 at p. 3; Portland General Electric, No. 130 at pp. 2–3; Webb, No. 133 at p. 1) Accordingly, many stakeholders advised against amending efficiency standards due to concerns that standards would further exacerbate supply chain challenges, increase the cost of transformers, delay transformer deliveries, and introduce additional strain on the electrical grid. (BIAW, No. 94 at p. 1; TMMA, No. 138 at p. 2; Entergy, No. 114 at p. 2; Alliant Energy, No. 128 at p. 1; Idaho Falls Power, No. 77 at pp. 1–2; Fall River, No. 83 at p. 1; Joint Associates, No. 68 at p. 2; Central Lincoln, No. 85 at p. 1; Chamber of Commerce, No. 88 at p. 3; NRECA, No. 98 at pp. 2–3; SBA, No. 100 at p. 5; Pugh Consulting, No. 117 at pp. 2–3; HVOLT, No. 134 at p. 6; Exelon, No. 95 at pp. 1–2; REC, No. 126 at pp. 1–3; Idaho Power, No. 139 at pp. 3, 6; Portland General Electric, No. 130 at pp. 1, 4–5; Indiana Electric Co-Ops, No. 81 at p. 1; NEPPA, No. 129 at p. 3; WEC, No. 118 at p. 3; TVPPA, No. 144 at p. 2; AISI, No. 115 at pp. 2–3; TVPPA, No. 144 at p. 1–2; NAHB, No. 106 at p. 4; CARES, No. 99 at p. 5; APPA, No. 103 at p. 2; Webb, No. 133 at p. 2; Allen-Batchelor Construction, No. 79 at p. 1; EEI, No. 135 at p. 1) NRECA urged DOE to not amend standards and instead focus on other means to incentivize amorphous cores without jeopardizing electric reliability. (NRECA, No. 98 at p. 8)

Many elected officials submitted comments describing how their local jurisdictions have been impacted by the national shortage of distribution transformers, expressing concern that the proposed standards could worsen the impacts of this shortage. (New York Members of Congress, No. 153 at p. 1; Kansas Congress Member, No. 143 at p. 1; Alabama Senator, No. 113 at p. 1; VA, MD, and DE Members of Congress, No. 148 at p. 1; Texas Congress Member, No. 149 at p. 1; Florida Members of Congress, No. 150 at pp. 1–2; South Dakota Congress Member, No. 145 at p. 1)

EEI attached a joint response to DOE's RFI on the Defense Production Act (87 FR 61306) reiterating a request that DOE dedicate funding to provide financial support to transformer manufacturers and producers of electrical steel. In that request, EEI stated that the primary challenges for transformer manufacturers include attracting and retaining a strong workforce and uncertainty of whether demand will continue to grow. (EEI, No. 135 at pp. 32–43)

DOE notes that this final rule pertains only to energy conservation standards for distribution transformers, and any efforts to amend other Federal regulatory programs and policies are beyond the scope of this rulemaking.

Several stakeholders specifically recommended that DOE abandon the proposed standard and instead issue a temporary waiver of the existing standards to allow more ubiquitous steel components to be used in the manufacturing process to increase transformer supplies. (NEPPA, No. 129 at p. 3; NWPPA, No. 104 at p. 2; TVPPA, No. 144 at p. 2; CARES, No. 99 at pp. 2–3)

As discussed, DOE has made modifications to its distribution transformer purchasing model to reflect the current challenges associated with the distribution transformer supply chain as discussed in section IV.F.3 of this document.

Pugh Consulting commented that the proposed rule will reduce competition for electric utilities, distribution transformer manufacturers, and home building construction companies. (Pugh Consulting, No. 117 at p. 4) DOE notes that its adopted standard allows for a diversity of core materials to be used and allows for manufacturers to largely maintain existing production equipment. Therefore, DOE does not anticipate reduced competition in the distribution transformer market. This conclusion is consistent with the assessment of the Attorney General as detailed in the letter published at the end of this final rule.

Separately, DOE also received feedback that distribution transformer shortages are delaying building projects, negatively impacting the housing market and impeding the availability of affordable housing in the U.S. (NAHB, No. 106 at p. 2; APPA, No. 103 at p. 5; Fall River, No. 83 at p. 1; Cleveland, No. 80 at p. 1; Ivey Residential, No. 82 at p. 1; BIAW, No. 94 at p. 1; Pugh Consulting, No. 117 at p. 4; NMHC & NAA, No. 97 at p. 1, Williams Development Partners, No. 84 at p. 1, Kansas Congress Member, No. 143 at p. 1; Allen-Batchelor Construction, No. 79 at p. 1; Alliant Energy, No. 128 at pp. 4–6) Several stakeholders also noted that the shortage of transformers is limiting the ability of utilities to interconnect new customers across the country, thereby impeding economic development in other sectors. (Alliant Energy, No. 128 at p. 2; EEI, No. 135 at pp. 10–11)

Several stakeholders specifically commented that the shortage of distribution transformers is delaying the construction of new housing developments which increases costs for homebuyers and, in some cases, may cause them to lose their rate lock on mortgage interest rates. (BIAW, No. 94 at p. 1; NAHB, No. 106 at pp. 4–5; NMHC & NAA, No. 97 at pp. 1–4; LBA, No. 108 at pp. 1–3)

Stakeholder comments demonstrate how distribution transformers play an integral role in the electrical grid, and how the impact that a shortage of transformers can have across industry and especially in certain infrastructure-oriented segments such as the housing market. DOE notes that the transformer industry is actively responding to current shortages of distribution transformers, with multiple major suppliers having announced capacity expansions in recent months and years (as discussed in chapter 3 of the TSD). While additional capacity takes time to build and the effects will not be immediately felt by the broader distribution transformer market, once online, these capacity expansions should help alleviate some of the current supply challenges.

DOE notes that, historically, amended efficiency standards have not significantly increased transformer lead times, and current transformer shortages began occurring long after the most recent energy conservation standards went into effect. This is demonstrated by the producer price index time series data for the electric power and specialty transformer industry, which shows relatively steady pricing from 2010 to 2020 followed by significant price increases starting in 2021.[104] However, DOE acknowledges that if investments in conversion costs compete with needed investments in capacity expansions, lead times for distribution

[104] U.S. Bureau of Labor Statistics, *Producer Price Index by Industry: PPI industry data for Electric power and specialty transformer mfg, not seasonally adjusted.*, Available online at: *https://www.bls.gov/ppi/databases/* (retrieved on 03/17/2024).

transformers could increase. At the same time, investment in new amorphous production equipment could allow for higher efficiency standards for specific equipment classes, while shifting existing production equipment to increase production of other equipment classes, thereby increasing total capacity to produce distribution transformers. DOE has considered the impact that amended standards could have on distribution transformers costs in section IV.C.2 of this document.

Several stakeholders specifically expressed concern that shortages of distribution transformers will reduce grid reliability, potentially impeding the ability of utilities to restore power following natural disasters and in emergency situations. (EEI, No. 135 at pp. 16–17, 28–29; Michigan Members of Congress, No. 152 at p. 1; Alliant Energy, No. 128 at p. 2; Portland General Electric, No. 130 at pp. 4–5, Pugh Consulting, No. 117 at p. 6; Florida Members of Congress, No. 150 at pp. 1–2; Entergy, No. 114 at p. 3; APPA, No. 103 at p. 12; Exelon, No. 95 at p. 3)

Other stakeholders commented that transformer shortages are negatively impacting grid resilience and modernization, and recommended that DOE prioritize restoring a steady supply of distribution transformers, which would facilitate electrification efforts. (Chamber of Commerce, No. 88 at p. 3; CARES, No. 99 at p. 2; EEI, No. 135 at pp. 4–5; Pugh Consulting, No. 117 at p. 7; Exelon, No. 95 at p. 4; Xcel Energy, No. 127 at p. 1; Alliant Energy, No. 128 at p. 3; Alliant Energy, No. 128 at p. 4; NMHC & NAA, No. 97 at p. 3; Ivey Residential, No. 82 at p. 1; NWPPA, No. 104 at pp. 1–2; New York House Representatives, No. 153 at p. 1; Michigan Members of Congress, No. 152 at p. 1; Florida Members of Congress, No. 150 at p. 1)

Portland General Electric commented that it has made changes to reduce the impact of shortages on its customers, such as delaying non-critical, non-customer jobs and exploring new sources, including offshore manufacturers, for refurbished transformers. (Portland General Electric, No. 130 at p. 3) Similarly, WEC commented that it has taken drastic steps to address the transformer shortages, and any additional supply chain issues will further limit the company's ability to support Federal and State grid resiliency initiatives, such as storm hardening and increasing capacity to support electric-vehicle-charging and solar installations. (WEC, No. 118 at p. 2)

EVgo commented that the distribution transformer supply chain shortages are impacting deployment of EV charging infrastructure and encouraged DOE to prioritize adequate supply of transformers so that regulations do not hamper EV charger deployment goals. (EVgo, No. 111 at pp. 1–2)

APPA commented that this rulemaking will increase lead times by 6–20 months and worsen supply chain constraints, which would negatively impact larger electrification efforts. (APPA, No. 103 at pp. 1–2, 6–7) NEMA commented that the proposed standards will increase production time and will negatively impact electrification and grid resiliency efforts while weakening domestic manufacturing capacity. (NEMA, No. 141 at pp. 1, 5) NEPPA commented that the proposed standards are infeasible and may inhibit electric grid reliability, electrification, and modernization goals. (NEPPA, No. 129 at p. 1)

NYSERDA commented that it anticipates a surge of distribution transformer installations as utilities make up for recent pandemic-related supply chain delays. NYSERDA further stated that any delay of standards could result in a significant number of less efficient transformers remaining in service well beyond 2050. (NYSERDA, No. 102 at p. 2)

DOE recognizes that a stable transformer supply chain will be essential to grid modernization. However, DOE disagrees with the notion that amended standards stand in opposition of those goals. As pointed out by the CEC, increasing transformer efficiency saves energy that would otherwise need to pass through the electrical grid, thereby reducing strain on the electrical grid. Further, as stated by NYSERDA, delaying efficiency standards for distribution transformers in a time when additional capacity is expected to come online in the near-to medium-term would result in the loss of significant energy savings which could otherwise be realized. As discussed above, providing certainty as to future transformer efficiency standards could incentivize manufacturers to invest in more efficient core production technology in an additive fashion that diversifies core materials and increases overall production in the near term. DOE also notes that the adopted standard levels provide the maximum improvement in energy efficiency while still being technologically feasible and economically justified. As discussed further, DOE has included in its consideration of whether efficiency standards are justified the potential effect that a given standard would have on existing distribution transformer shortages, on the domestic electrical steel supply, and on projected changes to the transformer market to support electrification.

DOE also received feedback on how the proposed rule might impact costs to consumers because of the effect that standards would have on the transformer supply chain.

Several stakeholders commented that the added costs of using amorphous core transformers, both in the original purchase price and increased installation/maintenance costs, will be borne by the end consumer. (NEPPA, No. 129 at p. 3; REC, No. 126 at p. 2; TMMA, No. 138 at p. 3; Fall River, No. 83 at p. 2; Idaho Falls Power, No. 77 at p. 1) NEPPA commented that during the 2016 rulemaking process, utilities and manufacturers predicted that forcing increased efficiency levels would cause increases to both per-unit cost and lead times. (REC, No. 126 at p. 2) NEPPA commented that prices are currently up to four times the predicted price and lead times are upwards of 188 weeks compared to 90-percent shorter lead times just a few years ago, with many suppliers not even providing a guaranteed price or lead time to small-volume purchasers. (NEPPA, No. 129 at p. 2)

Portland General Electric further stated that prices are spiking as utilities seek more transformers and that utilities are in a precarious position as they commit to buying and storing more transformers than may actually be needed. (Portland General Electric, No. 130 at p. 3) Webb advised against amending efficiency standards given the current volatility of the transformer market, with high material costs, restricted production capacity and labor resources, and increasing raw material costs all contributing to high prices and lead times for distribution transformers. (Webb, No. 133 at pp. 1–2) WEG commented that the initial costs of this rule outweigh the benefits, especially when considering current supply chains. (WEG, No. 92 at p. 1)

DOE notes that the price increases and extended lead times currently exhibited in the distribution transformer market do not appear to be the direct result of standards amended in the 2013 Standards Final Rule, as suggested by NEPPA. Rather, the price of distribution transformers stayed relative constant for several years following the implementation of standards in 2016.[105]

[105] U.S. Bureau of Labor Statistics, *PPI Commodity data for Machinery and equipment-Power and distribution transformers, except parts, not seasonally adjusted.* Available at *data.bls.gov/*

It was not until late 2020 or early 2021, when significant disruptions to the market and industry-wide supply chain challenges began to occur, that distribution transformer prices began to significantly increase. These price increases were directly correlated to price increases for grain oriented electrical steel, which nearly doubled in price from 2021 to 2023.[106] These price trends demonstrate how recent price hikes for distribution transformers have been more the result of increase demand, as opposed to amended efficiency standards. DOE has considered the potential impact that amended efficiency standards could have on transformer prices in section IV.C.2 of this document.

DOE also received comments relating to the specific challenges that the transformer supply chain might face in transitioning to amorphous cores.

Portland General Electric commented that a shift to amorphous core transformers would lead to even more widespread unavailability of distribution transformers as transformer manufacturers retool and redesign production, which would require new submittal and approval drawings to be provided to utilities. (Portland General Electric, No. 130 at p. 3) Entergy commented that the proposed standard creates an additional supply constraint for distribution transformers, creates technical issues that need to be vetted, increases costs, and hampers resiliency efforts in an area of the country that is critical to energy security. (Entergy, No. 114 at p. 4)

APPA commented that transformer manufacturers are not expanding due to concern that the NOPR would make investments obsolete, concerns over electrical steel availability, and labor shortages, which would be exacerbated by the additional labor needed to produce amorphous transformers. (APPA, No. 103 at p. 6) Webb recommended DOE confirm that manufacturers can gear up their factories in a timely manner to effectively produce the equipment required for the proposed standards. (Webb, No. 133 at pp. 1–2)

ERMCO and Exelon stated that the proposed rule would divert resources from resolving the current transformer supply crisis. (ERMCO, No. 86 at p. 1; Exelon, No. 95 at p. 2) ERMCO added that this redirect of resources will take focus off meeting current demand, which will inevitably open the door for overseas manufacturers to supply the US electrical grid. (ERMCO, No. 86 at p. 1) WEG commented that if implemented, the proposed standards will significantly reduce the supply of distribution transformers to the U.S. (WEG, No. 92 at p. 4) Southwest Electric commented that enforcing the proposed standards before sufficient capacity for both amorphous core material and copper is established could restrict availability of new transformers and further increase lead times. (Southwest Electric, No. 87 at p. 3)

Prolec GE commented that longer cycle times for amorphous could reduce production capacity up to 20 percent. (Prolec GE, No. 120 at p. 3) Similarly, Prolec GE commented that thinner laminations for lower-loss GOES grades affect total mill production capacity and make it difficult to justify shifting production to lower-loss steels. (Prolec GE, No. 120 at p. 10)

Eaton commented that prolonged labor and supply chain challenges have driven lead times up to 18 months for LVDT units and ranging from 2 to 4 years for liquid immersed units. Eaton added that a forced transition to amorphous will require multiple development projects and significant capital investment, exacerbating existing labor and material supply issues. (Eaton, No. 137 at pp. 2–3) Howard commented that the NOPR has created uncertainty causing electrical steel manufacturers not to build new silicon steel plants at a time when they are desperately needed. Howard stated that even absent amended standards, additional electrical steel capacity is needed to serve the EV market and increasing efficiency standards magnify these requirements. (Howard, No. 116 at p. 2) Howard went on to state that virtually all components of transformers are experiencing a shortage right now driven by the limited number of suppliers and global labor and material shortages. Howard encouraged DOE to delay the implementation of any standards until the existing transformer shortage is resolved and lead times are back to normal. (Howard, No. 116 at pp. 4–5) Hammond commented that it has expanded capacity by 20 percent in 2020, with another 20 percent planned in 2023, but has still been struggling to meet demand. Hammond added that all of the expanded capacity is for GOES core construction, not amorphous. (Hammond, No. 142 at p. 2) ABB stated that the transformer industry will be unable to provide an adequate supply of transformers to fuel grid modernization without a robust supply of transformer core steel. (ABB, No. 107 at p. 3)

SolaHD commented that distribution transformers are already very efficient, and due to the intricate designs, increasing efficiency by even a fraction of a percent could add weeks or months to lead times. (SolaHD, No. 93 at p. 2) SolaHD expressed concern that the proposed standards will worsen existing lead times, which are currently over 16 months times for medium- and high-voltage distribution transformers and 6–8 weeks for the LVDT units that SolaHD produces. SolaHD added that this might delay national efficiency improvements and electrification initiatives. (SolaHD, No. 93 at pp. 1–2)

SolaHD, ABB, NEMA, and APPA commented that the administration clearly recognized the severity of the current supply chain crisis for transformers given the use of the Defense Production Act to prioritize domestic transformer production. (SolaHD, No. 93 at p. 2; ABB, No. 107 at p. 3; NEMA, No. 141 at pp. 1–2; APPA, No. 103 at p. 5) Environmental and Climate Advocates commented that funds from the Bipartisan Infrastructure Bill and the Inflation Reduction Act can be used by utilities and buildings owners to cover the costs of new transformers. (Environmental and Climate Advocates, No. 122 at p. 2)

As previously stated, DOE notes the distribution transformer market is in a unique position in which capacity needs to be added to meet demand, regardless of the implementation of standards. This provides the opportunity for industry to bring capital equipment online through additions to existing capacity. In light of these comments, DOE has evaluated an additional TSL in which certain equipment classes remain at efficiency levels that can cost-competitively be met via GOES. DOE notes the adopted efficiency levels allows GOES to remain cost-competitive for a substantial volume of distribution transformer shipments, meaning that manufacturers can retain their existing capital equipment, thereby not worsening near-term supply chain issues.

DOE also notes that the standards adopted in this final rule will allow distribution transformers to cost-competitively utilize existing GOES capacity across many kVA ratings. As discussed, core production equipment generally carries flexibility to manufacture a range of core sizes. As such, if an existing piece of GOES core production equipment manufactures cores for 75 kVA, 100 kVA and 167 kVA, as an example, manufacturers can meet efficiency standards by shifting that equipment to increase 75 kVA and 100 kVA GOES cores and adding a new

pdq/SurveyOutputServlet (last accessed Nov. 3, 2023).

[106] Metal Miner, *Global M3 Price Index.* November 2023. Available at *agmetalminer.com/metal-prices/grain-oriented-electrical-steel/* (last accessed Nov. 3, 2023).

amorphous core production machinery to manufacture 167 kVA transformers. The resulting arrangement results in an increase in total transformer core production capacity as the amorphous line is invested in as an additive equipment line, as opposed to replacing existing GOES production equipment.

Further, DOE notes that the compliance period for amended standards has been extended beyond what was proposed in the January 2023 NOPR. DOE believes the additional time provided to redesign transformers and build capacity will further mitigate the risk of disrupting production necessary to meet current demand.

B. Screening Analysis

DOE uses the following four screening criteria to determine which technology options are suitable for further consideration in an energy conservation standards rulemaking:

(1) Technological feasibility. Technologies that are not incorporated in commercial products or in commercially viable, existing prototypes will not be considered further.

(2) Practicability to manufacture, install, and service. If it is determined that mass production of a technology in commercial products and reliable installation and servicing of the technology could not be achieved on the scale necessary to serve the relevant market at the time of the projected compliance date of the standard, then that technology will not be considered further.

(3) Impacts on product utility. If a technology is determined to have a significant adverse impact on the utility of the product to 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 would have significant adverse impacts on health or safety, it will not be considered further.

(5) Unique-pathway proprietary technologies. If a technology has proprietary protection and represents a unique pathway to achieving a given efficiency level, it will not be considered further, due to the potential for monopolistic concerns. 10 CFR 431.4; 10 CFR part 430, subpart C, appendix A, 6(c)(3) and 7(b).

In sum, if DOE determines that a technology, or a combination of technologies, fails to meet one or more of the listed five criteria, it will be excluded from further consideration in the engineering analysis. The reasons for eliminating any technology are discussed in the following sections.

The subsequent sections include comments from interested parties pertinent to the screening criteria, DOE's evaluation of each technology option against the screening analysis criteria, and whether DOE determined that a technology option should be excluded (''screened out'') based on the screening criteria.

1. Screened-Out Technologies

In the January 2023 NOPR, DOE screened-out the technology options listed in Table IV.6 and detailed the basis for screening in chapter 4 of the NOPR TSD.[107] DOE did not receive any comments on the screened-out technology options. As such, DOE has retained those technology options as screened-out.

Table IV.6 Screened-Out Technologies

Technology Option	Basis for Screening
Core Deactivation	Practicability to manufacture, install, and service; Adverse Impacts on Product Utility or Product Availability
Less-Flammable Insulating Liquids	Adverse Impacts on Health or Safety
Symmetric Core Design	Practicability to manufacture, install, and service.
23pdr075 and 23dr070 GOES Steel	Practicability to manufacture, install, and service.
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.

2. Remaining Technologies

Through a review of each technology, DOE concludes that the remaining combinations of core steels, winding configurations and core configurations as combinations of ''design options'' for improving distribution transformer efficiency met all five screening criteria to be examined further as design options in DOE's final rule analysis.

DOE determined that these technology options are technologically feasible because they are being used or

[107] Available at Docket No. EERE–2019–BT–STD–0018–0060.

have previously been used in commercially available products or working prototypes. DOE also finds that all of the remaining technology options meet the other screening criteria (*i.e.,* practicable to manufacture, install, and service; do not result in adverse impacts on consumer utility, product availability, health, or safety; and do not utilize unique-pathway proprietary technologies). For additional details, *see* chapter 4 of the final rule TSD.

DOE received comments from certain stakeholders suggesting that amorphous cores should be screened out as a technology option.

Regarding use of amorphous cores in high-kVA distribution transformers, Eaton commented that it is not aware of any amorphous core transformers that are commercially available beyond 1,500 kVA and therefore DOE should screen-out amorphous cores for distribution transformers beyond 1,500 kVA. (Eaton, No. 137 at p. 19) Eaton stated that manufacturers would need to resolve technical challenges before manufacturing amorphous cores over 1,500 kVA and therefore DOE should not evaluate efficiency standards for transformers above 1,500 kVA that cannot be met with GOES. (Eaton, No. 137 at p. 26) TMMA commented that amorphous is unproven for transformers larger than 2,500 kVA and therefore it is not clear that the proposed standards are technically feasible. (TMMA, No. 138 at p. 3) Prolec GE commented that amorphous is not proven all the way up to 5,000 kVA. (Prolec GE, No. 120 at p. 3) LBA commented that amorphous transformers have more limited capacity, which will require manufacturers to increase the number of transformers. (LBA, No. 108 at p. 3)

Carte commented that amorphous cores are highly susceptible to any outside pressure on the cores and as such cannot be used to secure the coils inside a transformer on larger kVA. (Carte, No. 140 at p. 2) Carte stated that certain manufacturers had not built amorphous core transformers beyond certain sizes due to these clamping limitations and encouraged DOE to investigate if large amorphous cores could be built. (Carte, No. 140 at p. 2) Carte added that developing new technology to be able to brace large amorphous cores could take years and cost hundreds of thousands of dollars. (Carte, No. 140 at p. 2)

DOE notes that amorphous transformers do exist over 1,500 kVA. Numerous foreign manufacturers advertise both liquid-immersed and MVDT distribution transformers above 1,500 kVA. One manufacturer in Korea markets 15,000 kVA amorphous oil-immersed transformers, with deliveries as early as 2007, and markets amorphous MVDT units up to 5,000 kVA.[108] One manufacturer in India markets amorphous liquid-immersed distribution transformers up to 5,000 kVA.[109] Dating back to the early 2010's, ABB offered an amorphous MVDT unit up to 4,000 kVA.[110] Further, in public utility bid data, DOE has observed numerous manufacturer bids for 2,500 kVA amorphous core distribution transformers (*see* chapter 4 of the TSD). While Carte is correct that amorphous cores do not have the same inherent mechanical strength as GOES, manufacturers have developed core clamps and bracing to provide the necessary mechanical strength. In some cases, this may even include using a strip of GOES steel on the exterior of an amorphous core to provide additional mechanical strength.[111]

Regarding use of amorphous cores in LVDT distribution transformers, Hammond commented that the performance of amorphous cores degrades above 160C and LVDTs frequently are rated with an insulation system capable of 220C, so there is insufficient technical data to understand how amorphous cores will perform long term in LVDT applications. (Hammond, No. 142 at pp. 2–3)

SolaHD expressed concern that amorphous cores are largely untested for LVDT distribution transformers, stating that amorphous cores are less flexible and more expensive than GOES. (SolaHD, No. 93 at p. 2) Schneider commented that amorphous will increase the sound emitted from distribution transformers, which likely won't be an issue for products installed outdoors or in large electrical rooms but may be an issue for LVDTs, which are typically in smaller rooms. (Schneider, No. 101 at p. 14) Eaton commented that there is a lack of technical data to validate the performance of amorphous cores for LVDT transformers. Eaton further stated that developing manufacturing processes for amorphous LVDT transformers will require significant investment, years of research and development, and impact required accuracy to meet customer specifications. (Eaton, No. 137 at p. 41)

DOE notes that Hammond did not provide any data or modeling as to the change in transformer core performance above 160C. However, distribution transformer temperature rise is governed by transformer losses. A more efficient transformer may not ever meet the insulation temperature limits. In the case of amorphous dry-type transformers, Schneider commented regarding K-factor rated transformers that computer modeling suggests that the reduced losses of amorphous LVDT units would place the thermal characteristics well below the insulation material. (Schneider, No. 101 at pp. 5–6) Further, in the amorphous LVDT and MVDT products marketed in international markets, it is common for transformers to be marketed with Class H or Class F insulation, corresponding to 150C and 115C temperature rise, or 220C and 185C performance.[112] [113] A comparison of the performance of these LVDT units to DOE modeled units is given in chapter 5 of the TSD and indicates that it is technically feasible to build LVDTs with amorphous cores that satisfy common customer specifications.

APPA stated that rewinding transformers, rather than purchasing a new transformer, can result in a lower cost and shorter lead time for utilities. (APPA, No. 103 at pp. 11–12) APPA commented that utilities today are rewinding up to 15 percent of their transformers due to the significant lead times. (APPA, No. 103 at pp. 11–12). APPA commented that the ability to rewind GOES transformers is a consumer utility that would be lost if DOE standards require amorphous cores. (APPA, No. 103 at pp. 11–12)

APPA stated that GOES transformer rewinding equipment is incompatible with amorphous cores and notes that amorphous rewinding equipment is far more complex and expensive. (APPA, No. 103 at pp. 11–12) DOE notes that amorphous core transformers can also be rewound, as acknowledged by APPA, and therefore DOE disagrees that the ability to rewind a transformer is lost if an amorphous core is used.

DOE notes that the transformer rebuilding/rewinding market has historically been relatively small. Rewinding a distribution transformer

[108] Cheryong Electric, *Power Products.* Available at *en.cheryongelec.com/eng/library/catalog.php.*

[109] Kotsons, *Power & Distribution Transformers.* Available at *www.kotsons.com/assets/images/Broucher.pdf.*

[110] ABB, *Responding to a changing world: ABB launches new dry-type transformer products,* 2012. Available at *library.e.abb.com/public/74cdbc97d4588a1cc1257ab8003a00b5/22-27%20sr105a_72dpi.pdf.*

[111] Advanced Amorphous Technology, *About Amorphous Distribution Transformer.* Available at *advancedamorphous.com/about-amorphous-distribution-transformer/* (last accessed Oct. 17, 2023).

[112] Toyo Electric, ''Dry-type Amorphous core transformer.'' Available at *www.toyo-elec.co.jp/en/products/dry-type-amorphous-core-transformer/* (last accessed Oct. 2023).

[113] Chu Lei Electric Co., ''Amorphous Transformers.'' Available online at: *www.powertransformer.com.tw/en/amorphous-transformers.html* (last accessed Oct. 2023).

requires additional labor (because labor is required both to deconstruct the transformer and rebuild it) that has made replacing a distribution transformer the preferred option when a transformer fails. While recently there has been an uptick in transformer rewinding, that is primarily a function of long lead times for new transformers.

Regardless of the core steel used to meet efficiency standards, rewinding of GOES transformers will continue to be an option for utilities for as long as existing GOES transformers remain in the field. Given that rewinding of transformers does not typically occur until late in a distribution transformer's lifetime, any existing utility investment in rewinding equipment will likely be used on the existing stock of transformers for many decades. Any investment in amorphous core rewinding equipment would likely be in an additive function and not impact near or medium-term ability to rewind transformers.

DOE notes that amorphous core transformers have been used as a technology option for high-efficiency transformers for many decades. While there are conversion costs, required to transition from producing GOES cores to amorphous cores, those costs are considered in the manufacturer impact analysis. Additionally, while amorphous cores are different than GOES cores and require a degree of technological understanding to properly use amorphous core transformers, the vast majority of liquid-immersed transformer manufacturers have some experience building amorphous core transformers, and numerous foreign manufacturers produce amorphous core transformers spanning a range of product classes. Further, manufacturers have the option to purchase finished amorphous cores from third-party electrical processing companies, which provides another avenue to producing amorphous core transformers. Based on the foregoing discussion, DOE has retained amorphous cores as a technology option for achieving higher efficiency standards in distribution transformers.

C. Engineering Analysis

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

1. Efficiency Analysis

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

For this final rule analysis, DOE used an incremental efficiency (design-option) approach. This approach allows DOE to investigate the wide range of design option combinations, including varying the quantity of materials, the core steel material, primary winding material, secondary winding material, and core manufacturing technique.

For each representative unit analyzed, DOE generated hundreds of unique distribution transformer designs by contracting with Optimized Program Services, Inc. (OPS), a software company specializing in distribution transformer design. The OPS software uses two primary inputs: (1) a design option combination, which includes core steel grade, primary and secondary conductor material, and core configuration, and (2) a loss valuation.

DOE examined number design option combinations for each representative unit. The OPS software generated 518 designs for each design option combination based on unique loss valuation combinations. Taking the loss value combinations, known in industry as A and B values and representing the commercial consumer's present value of future no-load and load losses in a distribution transformer respectively, the OPS software sought to generate the minimum TOC. TOC can be calculated using the equation below.

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

a. Representative Units

Distribution transformers are divided into different equipment classes, categorized by the physical characteristics that affect equipment efficiency. DOE's current equipment classes are detailed in section IV.A.2.

Because it is impractical to conduct detailed engineering analysis at every kVA rating, DOE conducts detailed modeling on ''representative units'' (RUs). These RUs are selected both to represent the more common designs found in the market and to include a variety of design specifications to enable generalization of results.

DOE detailed the specific RUs used in the NOPR analysis and those units' characteristics in chapter 5 of the NOPR TSD.[114] Each RU represents an individual transformer model referred to by a specific RU number (*e.g.,* RU1, RU2, etc.). DOE requested comment on its representative units as well as any data for potential equipment that may have a different cost-efficiency curve than those that can be represented by the representative units. 88 FR 1722, 1759–1760.

Regarding the characteristics of the representative units, Carte commented that RU3 uses a 150 kV BIL when, based on its primary voltage of 14.4 kV, it should use a 95 kV BIL or 125 kV BIL. (Carte No. 140 at p. 9)

DOE notes that representative units are selected to represent both common designs found on the market and to include a variety of design specifications to enable generalization of results. In the case of RU3, DOE selected a more conservative BIL rating to assist in generalization of result. The

[114] Available at Docket No. EERE–2019–BT–STD–0018–0060.

resulting design would be slightly more costly than a 95 kV BIL or 125 kV BIL and therefore represents a more conservative design than the most common design.

Regarding any units that have different cost-efficiency curves, Carte commented that high-impedance transformers still within the normal impedance range can be more challenging to meet efficiency standards. (Carte, No. 140 at p. 10) Carte commented that certain high-BIL transformers can have higher costs in order to meet the current efficiency levels as compared to the modeled BIL values. (Carte, No. 140 at pp. 9–10) Carte also identified multi-voltage transformers, and main and teaser transformers as other designs that have a very high-cost to meet NOPR levels using GOES. (Carte, No. 140 at pp. 9–10) Carte commented that meeting NOPR levels with GOES for main and teaser transformers increases costs by over 100 percent. (Carte, No. 140 at p. 9) DOE notes that the data cited by Carte refer to meeting EL 4 without using amorphous and does not discuss the cost increase if those same transformers were designed using amorphous cores.

DOE agrees that certain distribution transformers with uncommon features may have a more difficult time meeting any given efficiency level. However, typically those uncommon features result in higher costs both at baseline and under amended efficiency standards. Therefore, the incremental costs of building that same transformer are similar.

In the January 2023 NOPR, DOE also noted that while some applications may generally have a harder time meeting a given efficiency standard, most applications would generally be able to use amorphous cores to achieve higher efficiency levels. This includes designs at efficiency levels beyond the max-tech efficiency included in DOE's analysis. 88 FR 1722, 1759.

Eaton provided data demonstrating relatively consistent incremental costs for a variety of multi-voltage distribution transformers. (Eaton, No. 137 at p. 16) Eaton's data showed the cost-efficiency curve for a 500-kVA distribution transformer with an amorphous core and a variety of different primary voltage configurations. *Id.* Eaton's data showed that, depending on the voltage configuration, the baseline cost of a given transformer could vary. *Id.* However, the incremental cost associated with meeting any given efficiency level is similar for all transformers up until that specific design reaches its ''efficiency wall'' wherein the costs begin to increase rapidly.

As discussed in the January 2023 NOPR, Eaton's data shows that all designs for this unit can meet max-tech efficiency levels using an amorphous core; however, certain designs may have a harder time meeting the max-tech level as evidence by the higher costs. Further, Eaton's data shows that all of these designs have a similar incremental cost to increase efficiency from a baseline design through the NOPR levels, indicating that DOE's analysis is likely sufficient to encompass all of these designs.

While Carte commented that the incremental costs associated with meeting higher efficiency values is significant for distribution transformers with a variety of characteristics, DOE notes that Carte generally was referring to meeting higher standards without transiting to amorphous cores. DOE data similarly shows that meeting NOPR efficiency levels without using amorphous cores results in a significant cost increase. However, if using an amorphous core, higher efficiency levels can be met without extreme cost increases.

Several stakeholders commented regarding potential challenges associated with transformers' ability to handle harmonics and the potential challenges units would have in meeting efficiency standards.

Carte commented that solar inverters can create harmonics and speculated that the modifications needed to accommodate these harmonics may increase losses or not be achievable with amorphous cores. (Carte, No. 140 at p. 3) Carte commented that IEEE is evaluating the impact of solar generation on power quality and transformer design. *Id.* Nichols commented that the smart grid will have increased harmonics and additional control switches will be needed to monitor harmonics in addition to the amount of power. (Nichols, No. 73 at p. 1) Eaton commented that EV charging is likely to increase the amount of harmonics currents on transformers. (Eaton, No. 137 at p. 38)

Harmonics lead to excess losses in both the transformer core and transformer coil. Distribution transformer efficiency is measured using a sinusoidal wave function (*i.e.,* a current without harmonics) and therefore the impact of harmonic currents is not captured in the DOE's test procedure. The primary concern with harmonic currents is that they lead to excess heat generation. This excess heat can lead a transformer to overheat, even if it is not loaded at its maximum capacity. In dealing with harmonic currents, consumers can purchase harmonic mitigating transformers, K-factor rated transformers, or intentionally oversize transformers such that they never operate near their thermal loads. Regarding harmonic mitigating transformers, DOE notes harmonic mitigating transformers involve phase-shifted windings, which would be an option both at baseline and higher-efficiency levels, including with amorphous cores.

Powersmiths commented that DOE did not consider K-factor rated transformers in its representative units, which have larger footprints and windings in order to deal with the thermal impacts of harmonic currents, and stated that K-factor rated transformers have a lower achievable efficiency. (Powersmiths, No. 112 at p. 2) Eaton expressed concern that the OPS software may not accurately model the additional requirements for data center transformers, such as higher k-factors, lower flux density, and adjusted temperature rise. To demonstrate this, Eaton provided data comparing the specifications of an OPS design without a K-factor rating to the specifications of manufactured data center transformers with various K-factor ratings. (Eaton, No. 137 at p. 37)

Regarding modeling a K-factor rated transformer as a representative unit, DOE notes that a transformer that has a K-factor rating is designed to accommodate the additional thermal stress of equipment harmonics. Rather than trying to cancel out harmonic currents, as harmonic mitigating transformers do, K-factor rated transformers are typically oversized and derated to accommodate the additional heat from harmonics. As such, they have larger transformer cores and, therefore, higher no-load losses. However, DOE notes that more efficient transformers may not ever meet the insulation temperature limits. In the case of amorphous dry-type transformers, Schneider commented regarding K-factor rated transformers that computer modeling suggests that the reduced losses of amorphous LVDT units would result in thermal characteristics that are well below the insulation material. (Schneider, No. 101 at pp. 5–6) Further, amorphous cores have lower no-load losses per pound of core material. Hence, transformer with additional core material, such as K-factor rated transformers, would experience a greater improvement in efficiency relative to a baseline transformer. For these reasons, DOE has not included a specific representative unit for K-factor rated transformers and assumes the current representative units are sufficiently representative.

b. Data Validation

There can be differences between distribution transformer modeling and real-world data. In order to ensure DOE's modeled data reflects reality, DOE has relied on a variety of manufacturer literature, manufacturer public utility bid data, and feedback from stakeholders. DOE presented plots demonstrating how real-world data compares with modeled data in chapter 5 of the NOPR TSD.[115]

Regarding data validation for LVDTs, Powersmiths commented that DOE should ensure models meeting the proposed LVDT efficiency standards have actually been built because gaps exist between transformer modeling and real-world performance. (Powersmiths, No. 112 at p. 2) Powersmiths stated that the OPS modeling software does not accurately model stray and eddy losses, which for certain high-kVA designs can increase significantly and requires comparison of modeling to real designs in order to create a feedback loop to ensure the modeled designs can actually be built. (Powersmith, No. 112 at pp. 3–4) Powersmiths particularly expressed concern that DOE NOPR levels for LVDTs are largely based on amorphous core transformers which include deviations between the real-world data and the modeled data. (Powersmiths, No. 112 at p. 2) Powersmiths recommended that DOE work with industry to build, test, and verify modelled designs. (Powersmiths, No. 112 at p. 6) Eaton commented that using modeling to reflect what is achievable is a valid approach; however, software modeling does not necessarily include the manufacturer-to-manufacturer variability that exists in the real world. (Eaton, No. 137 at p. 41) Hammond commented that their modeling confirms that amorphous cores would be used to meet the NOPR efficiency levels for LVDTs. (Hammond, No. 142 at p. 2)

For dry-type transformers, DOE notes that chapter 5 of the NOPR TSD presents plots comparing the range of no-load and load loss combinations modeled for each representative unit to real world no-load and load loss data certified in NRCAN's database. These plots show the modeled design space for GOES transformers very closely aligns with the real-world design space shown in NRCAN's database. DOE notes that Powersmiths did not identify any unique features associated with amorphous core LVDTs that would result in the modeling for GOES to be accurate while the modeling for amorphous transformers to not be accurate. DOE has included additional data points taken from manufacturer literature in chapter 5 of the final rule TSD to demonstrate the real-world designs of amorphous LVDT transformers. DOE notes that this real-world data shows that the modeled amorphous design space very closely aligns with the real-world loss performance of amorphous core LVDTs.

For liquid-immersed transformers, DOE has similarly presented a comparison of the no-load and load loss combinations modeled in each representative unit as compared to real world manufacturer data. These plots show the modeled design space for both amorphous and GOES transformers very closely aligns with the real-world design space shown in manufacturer bid sheets.

Regarding the accuracy of DOE equipment costs, HVOLT commented that DOE's optimization model understates selling prices by as much as 40–50 percent and suspected that this because some of DOE's designs were developed as part of the previous rulemaking. (HVOLT, No. 134 at p. 6)

DOE notes that the difference between current prices and modeled prices is related to the fact that DOE modeling uses a 5-year average pricing while current prices for a baseline transformer are higher than the 5-year average. DOE's modeled prices have historically been in-line with real-world data, indicating that the physical construction of the transformers is accurate.

Current distribution transformer pricing is near its all-time high due to shortages. However, because most of the market relies on GOES, the price of GOES steel has increased more than the price of amorphous alloy. If DOE relied on current spot prices, as HVOLT suggests, the cost of the baseline transformer would increase considerably and be more in-line with the 40–50 percent increase cited by HVOLT. However, higher efficiency levels, particularly those with amorphous cores, would become far more cost competitive because amorphous alloy has not had the same demand pressure as GOES steel in recent years. DOE has updated prices for the final rule, as described in section IV.C.2 of this document, to reflect updated 5-year average prices.

Eaton submitted independently developed cost-efficiency and max-tech performance curves. Eaton provided a cost-efficiency curve for both amorphous and GOES transformers of similar kVA sizes as DOE's RU5 unit. (Eaton, No. at p. 19) DOE has provided a comparison between Eaton's data and DOE's modeled data in chapter 5 of the TSD. In general, the two are very closely aligned.

Eaton stated that its modeling showed some discrepancies between some of the max-tech efficiencies modeled by DOE and its max-tech efficiencies resulting from scaling representative units to high-kVA units. Eaton recommended DOE work with manufacturers to compare its modeling to real world max-tech values, particularly for omitted kVA ratings in the analysis. (Eaton, No. 137 at p. 20) DOE appreciates Eaton's work to validate its modeling and has relied on Eaton's modeling, in addition to other data sources, to modify DOE's scaling methodology for high-kVA units, as detailed in section IV.C.1.e of this document.

c. Baseline Energy Use

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

DOE's analysis for distribution transformers generally relies on a baseline approach. However, instead of selecting a single unit for each efficiency level, DOE selects a set of units to reflect that different distribution transformer purchasers may not choose distribution transformers with identical characteristics because of difference in applications and manufacturer practices. The mechanics of the customer choice model at baseline and higher efficiency level are discussed in section IV.F.3 of this document.

d. Higher Efficiency Levels

Regarding evaluating higher efficiency standards, numerous stakeholders commented that transformers are already efficient and stated that because efficiency is only increased by less than one percentage point, amended standards aren't worth the burdens that they would impose on manufacturers and the supply chains. (NMHC & NAA, No. 97 at p. 4; TVPPA, No. 144 at p. 1; APPA, No. 103 at p. 7; Pugh Consulting, No. 117 at p. 2; Alabama Senator, No.

[115] Available at Docket No. EERE–2019–BT–STD–0018–0060.

113 at p. 2; Webb, No. 133 at p. 2; CARES, No. 99 at pp. 2–3; AISI, No. 115 at p. 1; Strauch, No. 74 at p. 1; VA, MD, and DE Members of Congress, No. 148 at p. 2; New York Members of Congress, No. 153 at p. 2; EEI, No. 135 at pp. 44–47)

REC commented that, while amorphous cores provide a significant percentage reduction in losses, the increase in rated efficiency is small. (REC, No. 126 at p. 3)

CEC commented that distribution transformers are ubiquitous, and even small improvements to standards can have significant benefits to energy generators and distributors, manufacturers, consumers, and the environment. (CEC, No. 124 at p. 1)

Stakeholders are correct in their assessment that currently available distribution transformers are typically over 98 percent efficient. However, nearly all electricity passes through at least one distribution transformer and distribution transformers experience those losses 24 hours a day, 365 days per year, across a usable life that spans decades. Therefore, the losses from any single transformer, even if small in a particular instance, can be substantial in the aggregate and make up a considerable portion of a given transformer's total ownership costs.

Further, the efficiency levels proposed in the January 2023 NOPR represent a 2.5 to 50 percent reduction in transformer losses. DOE conducts its analysis to determine if the benefits of these operating cost and energy savings are economically justified. Hence, even though the change in efficiency appears to be a small number, the benefits of the evaluated efficiency standards may be substantial compared to existing performance, as reflected in DOE's analysis.

In evaluating higher efficiency levels, DOE relies on a similar approach to its baseline engineering analysis. DOE's modeled designs span the entire design space. In evaluating a higher efficiency level up until the max-tech that DOE considers, DOE evaluates the modeled units that would exceed the higher efficiency level. Then, rather than selecting a single unit, DOE applies a customer choice model to evaluate the distribution transformer that would be purchased if standards were amended.

DOE notes that for a given design option combination, the least efficient units typically tend to be the lowest cost unit.

Eaton commented that when meeting higher efficiency levels with GOES, manufacturers increase the core cross sectional area and decrease the flux density. (Eaton, No. 137 at pp. 21–22) The larger transformer cores require thicker conductors in order to maintain current density but using thicker conductors increases stray and eddy losses, which requires even larger conductor size to combat the additional stray and eddy losses. (Eaton, No. 137 at pp. 21–22) Eaton stated that at some point, the only option is to transition to copper windings, at which point the cost of the transformer skyrockets and significant cost increases are needed for even modest efficiency gains. (Eaton, No. 137 at pp. 21–22)

HVOLT commented that DOE proposed levels result in several products that will hit an efficiency wall where significant cost increases would result in very little efficiency improvement. (HVOLT, No. 134 at p. 2) HVOLT did not specify which products or clarify if that comment was across all core materials or only GOES.

Prolec GE commented that in their modeling, they found it was technically feasible to meet proposed standards with GOES cores and copper windings, but they would be at a cost disadvantage relative to amorphous cores that could use aluminum windings to meet efficiency standards. (Prolec GE, No. 120 at p. 8)

Powersmiths commented that the proposed standards for LVDTs are at max-tech, which does not leave sufficient margin for manufacturing and material batch variability. (Powersmiths, No. 112 at p. 2)

WEG commented that it is possible to reduce transformer losses to get halfway to the NOPR standards using a GOES core and copper windings, but the cost of the transformer would increase by 60 percent. (WEG, No. 92 at p. 1) NEMA commented that meeting the proposed LVDT efficiency standards with GOES would result in large weight increases and be impractical. (NEMA, No. 141 at p. 6)

Stakeholder comment is consistent with DOE modeling that it is technically feasible to meet many higher efficiency levels with GOES. However, beyond some efficiency levels it is no longer the lowest cost option. In evaluating higher efficiency levels, beyond a certain reduction in losses, transitioning from a GOES steel core to an amorphous core becomes by far the most cost effective approach for meeting higher-efficiency standards due to the significant reduction in no-load losses associated with an amorphous core.

As noted, the DOE test procedure specifies measuring efficiency at 50 percent PUL for liquid-immersed and MVDT distribution transformers and 35 percent PUL for LVDT distribution transformers. Distribution transformer performance at any given PUL can be approximated as no-load losses plus load losses multiplied by the square of the PUL. In meeting higher efficiency standards, manufacturers can employ design options that reduce no-load losses, reduce load losses, or a combination of the two. DOE models different design options that reduce both no-load losses and load losses and generally relies on manufacturer selling prices to determine what consumers are likely to purchase.

REC stated that if DOE measured energy efficiency at 100 percent PUL, the losses of an amorphous transformer could be higher than the losses of a GOES transformer. (REC, No. 126 at pp. 2–3) Idaho Power commented that it prefers technologies that reduce load losses rather than those that improve no-load losses. (Idaho Power, No. 139 at p. 2) Cliffs stated that when load levels are at 50 percent or higher, GOES transformers outperform amorphous transformers and provided plots to demonstrate this. (Cliffs, No. 105 at pp. 16–17) HVOLT recommended that DOE not implement any standards that exclude GOES given that amorphous cores hit peak efficiency at 20 percent loading and are less efficient than GOES above 50 percent loading. (HVOLT, No. 134 at p. 5) Cliffs further commented that AM transformers will not be able to sustain grid loading requirements, jeopardizing Department of Defense applications which rely upon resilient grid systems to supply backup power generation for mission requirements. (Cliffs, No. 105 at pp. 8–9)

NEPPA commented that amorphous cores may have slightly lower no-load losses than GOES cores, but they typically have higher load losses. NEPPA added that as loading levels increase due to electrification, amorphous core use does not guarantee overall lower losses when transformer loading increases over time. (NEPPA, No. 129 at p. 2) Idaho Power further recommended DOE evaluate transformer efficiency designs at higher load-losses (above 50 percent) instead of targeting increased efficiencies in no-load losses, given expected increases in loading with electrification. (Idaho Power, No. 139 at pp. 2–3) CARES and AISI commented that amorphous transformers are less efficient at higher loads and therefore the benefits of the NOPR are limited. (CARES, No. 99 at p. 4; AISI, No. 115 at p. 3) MTC commented that both low-loss GOES and amorphous core transformers provide similar energy savings at higher load factors. MTC provided data for both GOES and amorphous designs compliant with the European ECO–1 and ECO–2 efficiency standards to demonstrate this point. (MTC, No. 119 at pp. 13–15) MTC added that higher losses above 50 percent loading is not ubiquitous for amorphous transformers and is driven by DOE's testing requirement at 50 percent load. (MTC, No. 119 at p. 15)

DOE notes that its analysis considers technologies that reduce both no-load losses and load losses. As discussed, both amorphous core transformers and GOES core transformers have no-load and load losses wherein the no-load losses are approximately constant and the load losses vary with loading. DOE evaluates efficiency at 50 percent loading for liquid-immersed and MVDT distribution transformers and 35 percent for LVDT distribution transformers. DOE models any potential energy savings by evaluating the actual loading on transformers and accounts for both no-load and load losses as discussed in section IV.E of this document.

Cliffs and Carte stated that increasing demand on the electric grid will result in distribution transformers frequently operating beyond 50 percent load, which means that GOES transformers will have higher efficiency in the field. (Cliffs, No. 105 at pp. 16–17; Carte, No. 140 at p. 6) WEG commented that amorphous cores have their peak efficiency at lower loads and as loading increases as a result of electrification, a GOES design will be better optimized for higher loading. (WEG, No. 92 at p. 3) WEC and Xcel Energy commented that new load growth, such as the load growth associated with adding electric vehicles, will lead to load losses becoming more important and no-load losses becoming less important. (WEC, No. 118 at p. 1; Xcel Energy, No. 127 at p. 1) Webb commented that DOE should confirm amorphous transformers are efficient across a broad range of equipment loadings. (Webb, No. 133 at p. 2) NEMA commented that certain LVDTs could operate less efficiently if average load exceeds 35 percent. (NEMA, No. 141 at p. 6) Hammond commented that future electrification may result in many LVDT loaded above 35 percent and that puts greater emphasis on load losses, which favors GOES over amorphous. (Hammond, No. 142 at p. 2) Efficiency Advocates commented and provided data to show that, even under heavy load growth which would results in near 100 percent average load by 2058, DOE's proposed standards would still provide energy savings. (Efficiency Advocates, No. 121 at pp. 5–6)

Regarding the plots cited by Cliffs to support the claim that GOES transformers outperform amorphous transformers beyond 50 percent loading, DOE notes that Cliffs is making a comparison between a GOES and amorphous transformers that are equally efficient at 50 percent load. In evaluating higher efficiency standards, DOE makes a comparison between the baseline transformer (one purchased under current standards) and the transformer that would be purchased under amended efficiency standards. The plots cited by Cliffs show that both the GOES and amorphous designs at the proposed standards would outperform a baseline GOES design up to and beyond 100 percent loading. However, DOE notes that the GOES designs are expected to a require a significantly higher increase in both cost and weight, making them less favorable when compared to a current baseline design.[116]

Eaton commented that the efficiency of an amorphous transformer can be improved at little cost by using larger conductors up until the size limits for aluminum conductors, at which point it becomes very expensive to reduce losses further. (Eaton, No. 137 at p. 22) Eaton commented that it is a misconception that amorphous units are less efficient than GOES transformers above 50 percent PUL. (Eaton, No. 137 at p. 32) Eaton provided similar plots to Cliffs and noted that amorphous transformers that were designed to meet the current DOE 2016 efficiency levels required very little investment in the transformer windings due to their very low no-load losses. *Id.* As such, the amorphous core transformer is the lowest weight product but also has an efficiency curve that decreases considerably as loading increases. *Id.*

Eaton further commented that amorphous transformers designed to meet the proposed levels in the January 2023 NOPR include a modest investment in the transformer winding such that the efficiency of an amorphous design is greater than the baseline GOES design across all loading points. (Eaton, No. 137 at p. 32) Eaton stated that the incremental weight of the more efficient transformer is only 5.4 percent relative to the base amorphous design and ~1 percent relative to the base GOES design. *Id.* Eaton noted that while a GOES design can still meet the January 2023 NOPR levels and that GOES transformer would have a higher efficiency beyond 50 percent load than the amorphous transformer, considerably more material is needed, leading to a 50 percent weight increase. *Id.*

[116] *See* attachment 2 of comment submitted by HVOLT for underlying data (HVOLT, No. 134).

Eaton provided an additional design point to represent an amorphous design with additional investment windings, which reduces the load losses such that the amorphous design is more efficient across all loading points than even the GOES design that meets the January 2023 NOPR levels. *Id.* Eaton noted that this amorphous transformer can be built with an ''extremely modest weight increase of 14.5 percent'' relative to the baseline amorphous transformer. *Id.*

The data provided by Eaton further confirms that amorphous transformers can be designed to maintain high efficiency across the entire range of transformer loading. While a baseline GOES transformer may exhibit higher efficiency than a baseline amorphous transformer at higher loading, both DOE's modeling and stakeholder comment indicate that either an amorphous or a GOES transformer designed to meet amended efficiency standards would outperform a baseline transformer at all loading points. As such, DOE maintains that amorphous transformers stand to provide significant energy savings, even if average transformer loading were to increase.

Southwest Electric commented that they used current design data to model a baseline transformer and transformers that met the NOPR efficiency levels for 3-phase pad-mount transformers ranging from 112.5 kVA to 3750 kVA. (Southwest Electric, No. 87 at p. 2) Southwest Electric stated that in their case, all of the baseline transformer designs would use amorphous cores. (Southwest Electric, No. 87 at p. 2) Southwest Electric stated that based on their data, simply switching to an amorphous core would not be sufficient to meet the NOPR efficiency standards and additional investment would be needed in the conductor in order to meet the NOPR proposed levels. (Southwest Electric, No. 87 at p. 2)

DOE notes that manufacturer data from both Southwest Electric and Eaton suggest that for at least some 3-phase, liquid-immersed units, their design software suggest that the lowest cost design to meet baseline efficiency standards is using an amorphous core transformer. Despite this lower first cost, stakeholders have regularly stated that amorphous cores make up a very small percentage of the current distribution transformer market. DOE models amorphous core transformers across a range of efficiencies. Due to the substantial reduction in no-load losses associated with amorphous cores, a baseline transformer with an amorphous core can meet DOE 2016 efficiency standards with very little investment into the transformer windings. In evaluating higher efficiency models with amorphous cores, DOE designs include additional investment in the transformer windings which reduce load losses. DOE incorporates both the additional costs in the transformer core and the investment in the transformer windings in its analysis.

Schneider commented that lower losses correspond to lower impedance, which will increase the let-through current during short circuits. Schneider stated that this will increase the required ratings for connected equipment and impact system arc flash studies and protection for workers. Schneider further commented that impedance limits the impact of harmonics, which protects sensitive electronic loads. Schneider added that lower impedance will reduce voltage drop internal to LVDT devices. (Schneider, No. 101 at p. 14) APPA commented that while within the ''normal'' impedance ranges, amorphous transformers tend to have lower impedance which increases likelihood of an extremely high fault current. (APPA, No. 103 at p. 13) NEMA commented that higher efficiency standards met with GOES results in low impedance levels and anything below 4 percent or preferably 5 percent makes it difficult to design power systems and choose circuit breakers or fuses to handle fault currents. (NEMA, No. 141 at p. 6)

Metglas commented that impedance is fixed at 5.75 percent for units above 500 kVA and easily varied for smaller units. (Metglas, No. 125 at p. 5)

In the January 2023 NOPR, DOE discussed that the design options considered in the engineering analysis, including those that utilize amorphous metal, span a range of impedance values within the ''normal impedance'' range, as currently defined. 88 FR 1722, 1743. The design options considered in this final rule continue to span a range of impedance values at higher efficiency levels, both for designs that utilize GOES and those that utilize amorphous metal. Further, DOE notes that, while lower-loss transformer designs often have lower impedances, higher efficiency does not necessarily correlate to lower impedance.

Based on a review of manufacturer literature, DOE found that manufacturers often provide a range of impedance values for a given design, with customers able to request a specific impedance range to fit their application. DOE also observed transformers of varying levels of efficiency that provide the same impedance offerings.[117] [118] [119] This indicates that options exist to increase transformer impedance, even for higher efficiency transformers. Therefore, in this final rule, DOE did not further separate transformers based on impedance, aside from ensuring that a range of normal impedance values are available at higher efficiency levels.

e. kVA Scaling

In the January 2023 NOPR, DOE proposed to expand the scope of the distribution transformer definition to include units up to 5,000 kVA. 88 FR 1722, 1746 To assess the impact and potential energy savings associated with the expanded scope, DOE modeled three new representative units by using the scaling rules for transformer dimensions, weight, no-load losses, and load losses. 88 FR 1722, 1759–1760. DOE noted that it only includes distribution transformers in its downstream analysis if they would meet or exceed current energy conservation standards. Because transformers greater than 2,500 kVA have not historically been subject to energy conservation standards, DOE relied on the consumer choice model to determine the efficiency of a typical baseline unit that would be selected in the present market based on lowest first-cost. DOE did not consider any units which did not meet or exceed the efficiency of this assumed baseline unit. *Id.* DOE requested comment on its approach to modeling these high-kVA transformers.

DOE received numerous comments about scaling of design data for units beyond 2,500 kVA.

Several stakeholders noted that the percentage that stray and eddy losses contribute to load losses increases substantially at high-current values, which typically correspond to high-kVA ratings. Therefore, the 0.75 loss scaling cited by DOE does not hold when scaling to larger kVA ratings. (Eaton, No. 137 at p. 23; Prolec GE, No. 120 at pp. 7–9; HVOLT, No. 134 at pp. 6–7; Howard, No. 116 at p. 14; NEMA, No. 141 at p. 5; NEMA, No. 141 at p. 14; Powersmiths, No. 112 at p. 3)

Prolec GE commented that several of the high-kVA rated designs would be forced to use amorphous under the proposed standards because manufacturers would not be able to meet the proposed efficiency levels even with GOES and copper windings. (Prolec GE, No. 120 at p. 3) NEMA commented that for high-current transformers, it would be impractical to meet the NOPR efficiency levels with GOES as the flux density would be forced to such low values to make up for the increased buss and load losses. (NEMA, No. 141 at pp. 5–6)

Howard commented that designing transformers to meet the NOPR efficiency levels is technically feasible for transformers 2,500 kVA and less. However, the proposed standards beyond 2,500 kVA are not feasible and therefore DOE should not include them in any amended efficiency standards. (Howard, No. 116 at p. 5) Howard and HVOLT stated that they have not been able to develop any valid designs, even with amorphous cores, that meet the proposed standards at 3,750 kVA or 5,000 kVA. (Howard, No. 116 at p. 14; HVOLT, No. 134 at p. 7)

Eaton speculated that OPS modeling uses a constant stray loss percentage, which could significantly underestimate the percentage of load losses made up by stray losses for large kVA values. (Eaton, No. 137 at pp. 23–25) DOE notes that stray losses vary based on the design specifications of each specific unit modelled using the OPS design software and are not applied as a constant percentage of load losses.

Eaton noted that improper scaling of stray losses in DOE's analysis may result in an overestimation of the efficiencies that can be achieved and an underestimation of the transformer costs. (Eaton, No. 137 at p. 25) NEMA commented that for large kVA, high-current designs, stray and eddy losses can make up nearly 80 percent of the total load losses. (NEMA, No. 141 at pp. 13–14) HVOLT stated that stray and eddy losses can increase the load losses of a transformer over 3,000 kVA by as much as 50 percent. (HVOLT, No. 134 at p. 6)

Eaton commented and provided data to show that as conductor sizes increase to meet higher efficiency standards, stray losses increase as a percentage of total load losses. (Eaton, No. 137 at p. 23) Eaton's data shows that a baseline transformer has stray and eddy losses which make up about 15 percent of total load losses, whereas at max-tech, stray and eddy losses make-up 30 percent of load losses. (Eaton, No. 137 at p. 23)

Howard stated that the scaling DOE used to estimate the performance of

[117] Powersmiths, *E-Saver Opal Series,* Available at: *https://www.powersmiths.com/products/transformers/e-saver-opal-series/* (accessed on 3/17/2024).

[118] Eaton, *General Purpose Ventilated Transformers,* Available at: *https://www.eaton.com/us/en-us/catalog/low-voltage-power-distribution-controls-systems/ventilated-general-purpose-transformers.html* (accessed on 3/17/2024).

[119] Hammond Power Solutions, *HPS Sentinel Energy Efficient Distribution Transformers,* Available at: *https://americas.hammondpowersolutions.com/products/low-voltage-distribution/general-purpose-transformers* (accessed on 3/17/2024).

3,750 kVA units is not accurate due to the unique challenges associated with the high-current densities in these units. (Howard, No. 116 at p. 15) HVOLT commented that the 0.75 scaling relationship is only accurate over a narrow band of parameters and noted that scaling to high kVA ratings could result in underestimating winding losses by more than 50 percent. (HVOLT, No. 134 at p. 6) Howard recommended DOE refer to Annex G of IEEE C57.110–2018 to review industry data on stray and eddy losses and their relationship with kVA. (Howard, No. 116 at p. 16)

Eaton referenced DOE's compliance certification management system (CCMS) database and noted that the maximum reported percentage efficiencies do not increase beyond 1,000 kVA. Eaton stated this was evidence that the 0.75 scaling relationship does not hold for higher kVA values. (Eaton, No. 137 at pp. 27–28) Eaton noted that in evaluating the max-tech in their design software, some of the proposed standards for high-kVA transformers were near the technological limit, indicating a potential flaw in the 0.75 scaling relationship. (Eaton, No. 137 at p. 22)

Regarding scaling generally, NEMA commented that the 0.75 scaling relationship is only applicable across narrow kVA ranges. (NEMA, No. 141 at p. 4) NEMA commented that one of their members looked at their design data for MVDT transformers to investigate how accurate scaling transformer costs, no-load losses, and load losses from a 1,500 kVA and 300 kVA transformer were. (NEMA, No. 141 at p. 4) NEMA's member found that the actual scaling factor can vary widely and at times can be much more or much less than the DOE scaling factors. (NEMA, No. 141 at p. 4) NEMA stated that this variability was a result of constraints on wire sizes, impedance ranges, and construction requirements which can result in considerably different scaling relationships. (NEMA, No. 141 at p. 5) NEMA identified the small wire sizes associated with small kVA transformers as a very expensive component that skews the cost curve for small kVA units. (NEMA, No. 141 at p. 5) NEMA commented that the NOPR scaling factors only results in costs and losses that are within 5 percent across a small range of kVA values and not across the entire range of kVA values. (NEMA, No. 141 at p. 4)

Eaton provided data demonstrating how the max-tech in their design software varies based on secondary winding voltage and kVA. (Eaton, No. 137 at p. 18) Eaton's data shows that max-tech efficiency percentages tend to increase as the kVA increase up until a certain point. (Eaton, No. 137 at p. 18) Beyond that point, the current, and specifically the additional stray and eddy losses associated with the higher currents, can make a considerable difference as to the max-tech at a given kVA. (Eaton, No. 137 at p. 18) Eaton's data shows that for a 480Y/277 secondary voltage, the maximum efficiency occurs around 1,500 kVA. (Eaton, No. 137 at p. 18)

Based on the comments received, DOE re-evaluated the accuracy of the OPS modeling of stray and eddy losses for the 1,500 kVA units and how that modeling varies for high-current transformers. For DOE's modeled RU5, corresponding to a 1,500 kVA distribution transformer with 480Y/277 secondary, OPS modeling indicates that stray and eddy losses as a percentage of total load losses typically vary with design and with efficiency. While the exact percentage varies depending on the unique design specifications (*e.g.,* efficiency, whether copper or aluminum windings are used, core steel, *etc.*) the stray and eddy losses for most designs make up between 10–20 percent of total load losses. These values align well with the percentage of stray losses submitted in Eaton's comment for a similar unit and many of the stray and eddy values listed in Annex G of IEEE C57.110–2018. Therefore, DOE has concluded that the OPS modeling accurately accounts for stray and eddy losses.

Regarding the scaling of these OPS modeled representative units to other kVA ratings that are not individually modeled, DOE notes that scaling of units using power laws requires a variety of assumptions to remain valid. In chapter 5 of the TSD, DOE notes that these scaling relationships are valid if the core configuration, core material, core flux density, current density, physical proportions, eddy loss proportion, and insulation space factor are all held constant. DOE notes that in practical applications, it is rare that all of these are constant; however, scaling relationships can be used to establish reasonable estimates of performance.

Real world data can vary depending on what variables are changing between transformer designs. The data submitted by NEMA suggests that material cost scaling can be as low as 0.14 or as high as 1.13, no-load loss scaling can be as low as 0.33 or as high as 0.88, and load loss scaling can be as low as 0.51 or as high as 1.02. IEEE C57.110–2018 shows real world load loss scaling data with transformer kVA for solid cast transformers from 630 kVA to 20 MVA. These data show load loss scaling of 0.76. Data submitted by Eaton show that DOE's max-tech efficiency for 3-phase liquid-immersed distribution transformers are within a few tenths of a percentage point for the vast majority of kVA ratings, but the accuracy can vary depending on the current in the transformer.

All of the data identified by manufacturers indicate that for the vast majority of the kVA ranges, the scaling laws used in the NOPR are sufficient to provide reasonable estimates of performance, dimensions, costs, and losses. Stakeholder data also indicate that when the stray and eddy losses increase substantially, those scaling relationships may be less accurate.

However, stakeholders are correct in pointing out that for very high currents, stray and eddy losses may increase substantially such that it becomes much more difficult to meet efficiency standards. As noted in section IV.A.2.c of this document, industry standards recommend high-kVA transformers have higher-secondary voltages. As such, currents do not tend to reach problematic values. Beyond 1,500 kVA, there tend to be considerably more 480Y/277 secondary voltages and 208Y/120 voltages become relatively rare. However, if a manufacturer were to build a transformer with a very high-secondary current, the stray and eddy losses would make up a much greater percentage of the transformer load losses and, as such, the losses would scale at a higher factor. This was pointed out by numerous manufacturers who stated that DOE's proposed standards at 3,750 kVA may become technologically impossible.

To account for the change in scaling relationships that occur for high kVA transformers with high currents, DOE has established and evaluated a separate equipment class for large three-phase transformers with kVA ratings greater than or equal to 500 kVA, as discussed in section IV.A.2.c of this document. DOE has also revised its high-kVA scaled representative units to account for the increase in load losses that occurs as a result of growing stray and eddy losses. These scaling factors are discussed in chapter 5 of the TSD.

2. Cost Analysis

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

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

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

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

In the present case, DOE conducted the analysis by applying material prices to the distribution transformer designs modeled by OPS. The resulting bill of materials provides the basis for the manufacturer production cost (MPC) estimates for products at various efficiency levels spanning the full range of efficiencies from the baseline to max-tech. Markups are applied these MPCs to generate manufacturer selling prices (MSP). The primary material costs in distribution transformers come from electrical steel used for the core and the aluminum or copper conductor used for the primary and secondary winding. In the January 2023 NOPR, DOE noted that while prices have been up in recent years, it is difficult to say for certain how prices will vary in the medium to long term and, therefore, DOE relies on a 5-year average in its base scenario and evaluates how the results would change with different pricing scenarios. 88 FR 1722, 1765.

Regarding the cost analysis generally, WEC commented that based on information received from manufacturers, the costs used to support the NOPR are out of date and do not reflect current costs. (WEC, No. 118 at p. 1) APPA commented that DOE did not consider the recent rapid increases in transformer costs; APPA provided data indicating that the cost of transformers has increased substantially since 2018. (APPA, No. 103 at p. 7–8)

DOE data confirm that prices for distribution transformers have been up significantly from their historical averages. However, it is difficult to say for certain how those prices will vary in the medium to long term. The distribution transformer producer price index was approximately constant between 2010 and 2020, a time period that included implementation of two sets of energy efficiency standards (initial standards went into effect in 2010 and amended standards went into effect in 2016). Beginning in 2021, the producer price index of distribution transformers began to increase substantially through mid-2022. Since mid-2022, prices have remained approximately constant.

As discussed in section IV.A.5 of this document, the current distribution transformer shortage is largely driven by a supply-demand imbalance that exists across both distribution transformers and many electric and grid-related products. Considerable manufacturer investments in capacity increases have been publicly announced, including new locations which serve to expand accessible local labor markets. However, it is difficult to predict with certainty how the price of distribution transformers will vary when supply rises sufficiently to expected demand. DOE continues to rely on a 5-year average in its analysis.[120] The five-year period preceding this rulemaking includes price increases in addition to those accounted for in the NOPR. Accordingly, material and transformer prices are generally higher in this final rule than in the NOPR. Additional comments on specific material prices are discussed in the sections that follow.

a. Electrical Steel Prices

Electrical steel is one of the main material costs in distribution transformers and as such makes up a significant percentage of manufacturer production costs. Using lower-loss core materials is one of the primary tools for improving the energy efficiency of distribution transformers. As such, the relative costs associated with transitioning from the current baseline core materials to lower-loss core materials has a considerable impact on the cost effectiveness of amended efficiency standards.

In the January 2023 NOPR, DOE relied on 5-year average pricing for the various grades of electrical steel evaluated. 88 FR 1722, 1765–1767. In response to stakeholder comments submitted on the August 2021 Preliminary Analysis TSD that amended standards may introduce higher volatility that may make 5-year average prices inaccurate, DOE stated that historically, when amended standards have been adopted, core material manufacturers have increased capacity of the electrical steel grades needed to meet amended efficiency standards. *Id.*

DOE stated that substantial volatility has characterized the U.S. steel market, including the existing transformer core steel market, over the last several decades. From 2000 to 2007, U.S. steel markets, and more specifically the U.S. electrical steel market, began to experience pressure from several directions. Demand in China and India for high-efficiency, grain-oriented core steel contributed to increased prices and reduced global availability. Cost-cutting measures and technical innovation at their respective facilities, combined with the lower value of the U.S. dollar, enabled domestic core steel suppliers to become globally competitive exporters.

In late 2007, the U.S. steel market began to decline with the onset of the global economic crisis. U.S. steel manufacturing declined to nearly 50 percent of production capacity utilization in 2009 from almost 90 percent in 2008. Only in China and India did the production and use of electrical grade steel increase for 2009.[121] In 2010, the price of steel began to recover. However, the recovery was driven more by increasing costs of material inputs, such as iron ore and coking coal, than broad demand recovery.

In 2011, core steel prices again fell considerably. At this time, China began to transition from a net electrical steel importer to a net electrical steel exporter.[122] Between 2005 and 2011, China imported an estimated 253,000 to 353,000 tonnes of electrical steel. During this time, China added significant domestic electrical steel production capacity, such that from 2016 to 2019 only about 22,000 tonnes were imported to China annually. China also exported nearly 200,000 tonnes of electric steel annually by the late 2010s.

Many of the exporters formerly serving China sought new markets around 2011, namely the United States. The rise in U.S. imports at this time hurt domestic U.S. steel manufacturers, such that in 2013, domestic U.S. steel stakeholders filed anti-dumping and countervailing duty petitions with the U.S. International Trade

[120] Engineering results with current pricing are included in Appendix 5B of the TSD.

[121] International Trade Administration. *Global Steel Report.* Available at *legacy.trade.gov/steel/pdfs/global-monitor-report-2018.pdf* (last accessed Sept. 1, 2022).

[122] Capital Trade Incorporated, *Effective Trade Relief on Transformer Cores and Laminations,* 2020. Submitted as part of AK Steel comment at Docket No. BIS–2020–0015–0075 at p. 168.

Commission.[123] The resulting investigation found, however, that ''industry in the United States is neither materially injured nor threatened with material injury by reason of imports of grain-oriented electrical steel . . . to be sold in the United States at less than fair value.'' [124]

In the amorphous ribbon market, the necessary manufacturing technology has existed for many decades and has been used in distribution transformers since the late 1980s.[125] In many countries, amorphous ribbon is widely used in the cores of distribution transformers.[126] Significant amorphous ribbon use tends to occur in regions with relatively high valuations on losses (*e.g.,* certain provinces of Canada, certain U.S. municipalities).

Beginning in 2018, the U.S. government instituted a series of import duties on aluminum and steel articles, among other items. Steel and aluminum articles were generally subject to respective import duties of 25 and 10 percent *ad valorem.*[127] 83 FR 11619; 83 FR 11625. Since March 2018, several presidential proclamations have created or modified steel and aluminum tariffs, including changes to the products covered, countries subject to the tariffs, exclusions, *etc.*[128]

Another recent trend in distribution transformer manufacturing is an increase in the rate of import or purchase of finished core products. The impact of electrical steel tariffs on manufacturers' costs varies widely depending on if manufacturers are purchasing raw electrical steel and paying a 25-percent tariff on imported steel, or if they are importing finished transformer cores which, along with distribution transformer core laminations and finished transformer imports, are not subject to the tariffs. Some stakeholders have argued that this trend toward importing distribution transformer cores, primarily from Mexico and Canada, is a method of circumventing tariffs, as electrical steel sold in the global market has been less expensive than domestic electrical steel on account of being allegedly unfairly traded.[129] [130] Conversely, other stakeholders have commented that this trend predated the electrical steel tariffs and that importation of transformer components is often necessary to remain competitive in the U.S. market, given the limited number of domestic manufacturers that produce transformer laminations and cores.[131] [132]

On May 19, 2020, the U.S. Department of Commerce (DOC) opened an investigation into the potential circumvention of tariffs via imports of finished distribution transformer cores and laminations. 85 FR 29926. On November 18, 2021, DOC published a summary of the results of their investigation in a notice to the **Federal Register**. The report stated that importation of both GOES laminations and finished wound and stacked cores has significantly increased in recent years, with importation of laminations increasing from $15 million in 2015 to $33 million in 2019, and importation of finished cores increasing from $22 million in 2015 to $167 million in 2019. DOC attributed these increases, at least in part, to the increased electrical steel costs resulting from the imposed tariffs on electrical steel. In response to its investigation, DOC stated it is exploring several options to shift the market toward domestic production and consumption of GOES, including extending tariffs to include laminations and finished cores. No trade action has been taken at the time of publication of this final rule. 86 FR 64606.

More recently, DOE learned from stakeholders during manufacturer interviews and from public comments that pricing of electrical steel has risen such that in the current market, the price of foreign electrical steel, without any tariffs applied, is similar to the price of domestic steel. (Powersmiths, No. 46 at p. 6; Carte, No. 54 at p. 3) These recent price increases, particularly in foreign-produced electrical steel, were cited as being a result of both general supply chain complications and increased demand for non-oriented electrical steel from electric motor applications. (NEMA, No. 50 at p. 9; Powersmiths, No. 46 at p. 5; Zarnowski, Public Meeting Transcript, No. 40 at p. 36; Looby, Public Meeting Transcript, No. 40 at p. 37)

For the January 2023 NOPR, DOE stated that rather than constructing sensitivity analysis scenarios to reflect every potential combination of factors that may affect steel pricing, DOE relies on a 5-year average pricing for its core steel. DOE requested comment on the market, prices, and barriers to added capacity for both amorphous and GOES. 88 FR 1722, 1767.

Regarding the impact of other products on GOES and amorphous supply, Howard agreed that the price of GOES has increased significantly based on NOES becoming a more valuable investment and utilizing similar production equipment to GOES, thereby occupying some of the production capacity that otherwise would produce GOES, leading to material shortages of GOES. (Howard, No. 116 at p. 5) ABB commented that shortages of domestic GOES and likely amorphous would require transformer manufacturers to import electrical steel and bear the cost of tariffs, adding to the cost of transformers. (ABB, No. 107 at p. 3)

Howard commented that competition for amorphous ribbon is limited to low-volume and niche products, including brazing foil and high-frequency transformers. (Howard, No. 116 at p. 18) Metglas added that amorphous is almost exclusively used in distribution transformers, without other significant sources of competition. (Metglas, No. 125 at pp. 5–6) Efficiency and Climate Advocates commented that the proposed rule will improve the transformer supply chain because amorphous does not have as much price competition from EVs as GOES. (Efficiency and Climate Advocates, No. 154 at p. 1)

NAHB commented that amorphous metals are used in aerospace, medical devices, electric motor parts, and robotics. (NAHB, No. 106 at pp. 10–11) NAHB stated that demand for both amorphous metals and GOES will continue to increase due to grid modernization. *Id.* NAHB stated that, although amorphous metals are not suited to EV motors, they are well suited for other applications in EV manufacturing and will experience increased demand within that segment of the automotive market. (NAHB, No. 106 at pp. 10–11)

Stakeholder comments confirm that competition from other products is greater for GOES than it is for amorphous. These statements generally confirm DOE's January 2023 NOPR observations as to how the price of

[123] U.S. International Trade Commission, *Grain-Oriented Electrical Steel from Germany, Japan, and Poland,* Investigation Nos. 731–TA–1233, 1234, and 1236. September 2014.

[124] *Id.*

[125] DeCristofaro, N., *Amorphous Metals in Electric-Power Distribution Applications,* Material Research Society, MRS Bulletin, Volume 23, Number 5, 1998.

[126] BPA's Emerging Technologies Initiative, *Phase 1 report: High Efficiency Distribution Transformer Technology Assessment,* April 2020. Available at *www.bpa.gov/EE/NewsEvents/presentations/Documents/Transformer%20webinar%204-7-20%20Final.pdf.*

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

[128] Congressional Research Service, *Section 232 Investigations: Overview and Issues for Congress,* May 18, 2021, Available at *fas.org/sgp/crs/misc/R45249.pdf.*

[129] (AK Steel, Docket No. BIS–2020–0015–0075 at pp. 43–58).

[130] (American Iron and Steel Institute, Docket No. BIS–2020–0015–0033 at pp. 2–5).

[131] (Central Maloney Inc., Docket No. BIS–2020–0015–0015 at p. 1).

[132] (NEMA, Docket No. BIS–2020–0015–0034 at pp. 3–4).

GOES has risen more in the previous 5-years than the price of amorphous alloy.

Southwest Electric commented that the five-year average price of GOES is much lower than the current price of GOES and therefore DOE should update its cost models to reflect the more likely costs from 2023–2027, rather than incorporating the discounted prices that existed between 2017 and 2021. (Southwest Electric, No. 87 at p. 3) NEMA commented that the pricing of GOES is impacted by global demand and stated that some foreign manufacturers of GOES have committed part of their production capacity to serving their domestic markets. As such, this foreign GOES capacity is no longer available to serve the U.S. transformer market. (NEMA, No. 141 at p. 14) NAHB stated that energy rationing policies in China increased electrical steel prices in 2021–22 and, although prices have begun to stabilize, they are expected to increase again as demand for GOES and NOES rises. (NAHB, No. 106 at p. 11) Webb questioned whether the tariffs were exacerbating industry challenges. (Webb, No. 133 at p. 2) Carte commented that the market should decide what steel to use, stating that the recent increase in GOES prices paired with increased competition from NOES might naturally shift the market toward increased usage of amorphous material. (Carte, No. 140 at pp. 4–5)

DOE reiterates that there are a number of factors that can impact core material pricing, including competition from other markets, disruptions to supply chains, trade actions from both the U.S. and foreign countries, and increased demand. DOE has updated its base material prices in this final rule based on 5-year averages to capture more recent pricing trends as well as broader market developments. In general, the five-year average prices in this final rule are greater than the prices in the January 2023 NOPR, consistent with the observations from stakeholders.

DOE received numerous comments suggesting that the future price of materials could be dependent on DOE's policy choice as to whether to amend efficiency standards.

Howard commented that revised standards would further increase the demand for GOES and that its preliminary data shows transformer prices could be 50–125-percent greater than today's prices. (Howard, No. 116 at p. 5) Prolec GE stated that electrical steel price volatility is expected to continue or become worse unless current supply and demand issues are resolved. (Prolec GE, No. 120 at pp. 10–11) Prolec GE added that increased demand coupled with limited supply for lower-loss steels, both amorphous and GOES, will lead to price hikes. (Prolec GE, No. 120 at pp. 10–11) Regarding the price of amorphous ribbon, Eaton commented that DOE should consider the possibility that amorphous prices will increase to curtail demand, causing distribution transformer prices to increase 50–100 percent whether GOES or amorphous is used. (Eaton, No. 137 at p. 26)

Metglas commented that the price of amorphous ribbon has been stable relative to GOES over the last decade and additional amorphous ribbon capacity would drive down the fixed costs of amorphous ribbon and cores, which would improve the value of amorphous relative to GOES. (Metglas, No. 125 at pp. 5–6)

DOE notes that both GOES and amorphous core production tend to carry volume-based efficiencies. In Canadian markets, stakeholders have noted that while amorphous core transformers previously had a 10% cost-delta relative to GOES transformers, that cost-delta has fallen such that costs today are ''more or less even'' with GOES transformers.[133] DOE further notes that the adopted standards include equipment classes with substantial volume where both GOES and amorphous are expected to be cost-competitive. DOE also notes that the compliance period for amended standards has been extended, from the 3-year compliance period proposed in the January 2023 NOPR to a 5-year compliance period adopted in this final rule. As discussed further below, DOE has considered comments at to what length of compliance period is necessary to ensure a competitive market.

Howard commented that, while current cost structures indicate amorphous is the cost effective option for meeting the proposed efficiency standards, shortages of amorphous would increase amorphous costs and decrease GOES costs, meaning GOES could remain a cost effective option. (Howard, No. 116 at p. 3) Howard commented that both amorphous and GOES prices are expected to increase due to tariffs and increased demand due to the larger cores needed to meet the proposed efficiency standards. (Howard, No. 116 at p. 17) TMMA commented that the challenges associated with transitioning to amorphous cores will cause a further increase in the cost of producing and delivering a transformer, which will ultimately be borne by consumers. (TMMA, No. 138 at p. 3) WEG commented that the constrained supply of amorphous metal will significantly increase the cost of distribution transformers, amassing to $20M when applied across all of WEG's products. (WEG, No. 92 at p. 2) APPA commented that its current quotes from one vendor indicate that there would be a significant increase in costs if purchasing amorphous core transformers. (APPA, No. 103 at pp.7–8)

Prolec GE commented that DOE's analysis underestimates incremental costs because it is unrealistic that the market will fully transition to amorphous cores. (Prolec GE, No. 120 at p. 3) Prolec GE commented that, because the supply of amorphous ribbon is insufficient to serve the present market, manufacturers would be required to produce GOES transformers with a 40–70-percent increase in incremental cost. (Prolec GE, No. 120 at p. 2) TMMA added that an insufficient supply of amorphous will force manufacturers to use GOES to meet standards, leading to heavier transformers and higher costs that will be passed on to consumers. (TMMA, No. 138 at pp. 3–4) Southwest Electric stated that amorphous prices should be updated as well to reflect the expected cost increases that would occur if DOE's NOPR efficiencies go into effect in 2027. (Southwest Electric, No. 87 at p. 3) Powersmiths commented that DOE's costing estimate for amorphous transformers is flawed because a 5-year average includes low demand of the Covid pandemic period and does not properly reflect current market prices, which are nearly double and not expected to decline. (Powersmiths, No. 112 at p. 3) Prolec GE commented that heavy investments in increasing amorphous production capacity would be required to meet demand, implying that an ROI cost would be added for new production. (Prolec GE, No. 120 at p. 10) Alliant Energy commented in support of numerous manufacturers who expressed concern that conversion to amorphous cores by 2027 would increase prices and worsen existing supply chain concerns. (Alliant Energy, No. 128 at p. 2)

As noted, the current market for distribution transformers is experiencing an imbalance in supply and demand that has led to price increases for distribution transformers in recent years. This has also led to an increase in the price of GOES material needed to build distribution transformers. Compounding these price

[133] Bonneville Power Administration, *Low-Voltage Liquid Immersed Amorphous Core Distribution Transformers.* 2022. Available at *www.bpa.gov/-/media/Aep/energy-efficiency/emerging-technologies/ET-Documents/liquid-immersed-dist-transformers-final-22-02-16.pdf* (last accessed Oct. 30, 2023).

increases is the fact that there is only a single domestic supplier of GOES and, with tariffs on imported electrical steel, domestic transformer manufacturers are generally limited to purchasing M3 [134] steel from the single domestic GOES supplier. Manufacturers do have the option of purchasing electrical steel from global suppliers, but that would mean paying a 25-percent tariff and result in even higher electrical steel prices. These factors have left manufacturers with a limited supply of core material available for distribution transformer production.

In theory, manufacturers—under current standards—have the option of building amorphous transformers if the price of GOES transformers becomes prohibitively expensive. However, amorphous transformers require different capital equipment, meaning that manufacturers cannot easily switch between amorphous and GOES without new capital investments. As a result, the demand for GOES steel has increased by more than the demand for amorphous ribbon.

Data submitted in Eaton's comment indicates that for a 1,500 kVA, 3-phase liquid immersed transformer, an amorphous transformer is less expensive at baseline than a GOES transformer. Further, the proposed efficiency levels can be met with virtually zero incremental costs relative to a GOES transformer meeting efficiency standards today. If DOE applied current spot prices, as stakeholders have suggested, the baseline GOES transformer would get considerably more expensive while amorphous costs would remain relatively steady.

Regarding stakeholder concerns that incremental costs will be greater than DOE's analysis predicts due to a limited supply of amorphous metal, DOE notes that it has constrained the consumer choice model in this final rule to reflect the actions manufacturers will take given their existing production equipment and concerns over core steel supply. Specifically, consumers are assumed to meet standards with GOES up to EL 2. (*See* section IV.F.3.a of this document). Further, the adopted standards are expected to be met via a combination of GOES and amorphous core steel, such that a limited supply of amorphous ribbon will not be a constraining factor in meeting amended standards. As such, DOE does not anticipate the supply of amorphous metal to become significantly constrained as a result of standards such that the incremental costs modeled in DOE's analysis to meet amended efficiency standards would greatly increase. Eaton expressed concern that relying on a single supplier of amorphous could create a virtual monopoly that would prevent competition from keeping prices in check. Accordingly, Eaton recommended DOE consider providing pricing and availability assurances until the market can create additional competition. (Eaton, No. 137 at p. 27) NEMA commented that it anticipates production of amorphous cores to be the bottleneck in meeting the NOPR efficiency standards. (NEMA, No. 141 at p. 14) NEMA stated that because it knew of just one domestic manufacturer of amorphous cores, there would likely be a dramatic increase in material price if the entire market is reliant on a single supplier. (NEMA, No. 141 at p. 14) NEMA commented that the NOPR would establish a monopoly on amorphous ribbon, which will increase costs and lead times. (NEMA, No. 141 at p. 3) NRECA commented that the proposed standards could eliminate production of GOES while likely creating a monopoly supplier for amorphous. (NRECA, No. 98 at p. 3)

Regarding the notion that amended efficiency standards would significantly increase amorphous material prices by providing a monopoly to the single domestic supplier, DOE notes that the current distribution transformer market operates with a single domestic supplier of GOES and multiple foreign suppliers. As discussed in section IV.A.4.a of this document, in the presence of amended standards, the distribution transformer market is expected to be subject to the same dynamics present in the current market, even at efficiency levels expected to be met with amorphous.

DOE does not assume having a single domestic supplier of GOES leads to monopolistic pricing. DOE notes that domestic GOES experiences competition from foreign-produced GOES. While direct imports of raw GOES are subject to tariff, transformer cores and laminations are not subject to tariffs. As previously discussed, transformer manufacturers rely on a combination of domestic steel—to produce their own cores—and imported cores (that use foreign-produced steel).

Similarly, DOE does not assume that because there is currently only a single domestic supplier of amorphous today, that there will be monopolistic pricing of amorphous in the presence of amended efficiency standards. Similar to GOES transformers, amorphous ribbon experiences competition from foreign-produced amorphous for which direct imports are subject to tariffs but transformer cores are not. In both cases, there are foreign competitors and opportunity for other suppliers to enter the market.

However, there is uncertainty in the short-term price of electrical steel, with a variety of factors impacting core steel pricing. Short-term prices could be driven by policy decisions and decisions of select market actors, including decisions made by distribution transformer manufacturers, amorphous ribbon manufacturers, and GOES steel manufacturers. The current market has limited supply of both amorphous and GOES steel with better loss performance than M3. Long-term pricing is driven by supply and demand, as well as the prices of the underlying commodities. DOE's updated 5-year pricing is intended to estimate a competitive market for core materials. While many factors are influencing competition in the distribution transformer market, the variety of supply pathways to produce transformers (*e.g.,* domestically producing transformer core, importing transformer cores and domestically producing transformers, or importing finished transformers) support the continued existence of a competitive market for core materials in the long-term.

Further, DOE notes while the majority of the distribution transformer shipments can meet adopted efficiency standards using either GOES or amorphous, for certain equipment classes DOE is adopting standards at EL4, which is likely to be met via amorphous cores. The expected increase in amorphous core production equipment to meet the adopted standards for equipment classes set at EL4 is likely to send a demand signal to amorphous alloy producers, thereby increasing amorphous supply. Further, because amorphous core production equipment can manufacture a range of transformer sizes, it is likely that additional competition will occur between GOES and amorphous core equipment classes set at EL2 for liquid-immersed distribution transformers.

Efficiency standards have a multi-year compliance period and stakeholders are able to plan and invest such that a competitive market exists. Indeed, DOE notes that the compliance period for amended standards has been extended, from the 3-year compliance period proposed in the January 2023 NOPR to a 5-year compliance period adopted in this final rule. As previously discussed, DOE has considered comments at to

[134] M3 steel is the short-hand naming convention for conventional (*i.e.,* not high-permeability) GOES that is 0.23 mm thick. It makes up the majority of domestically produced GOES used in distribution transformers in the U.S.

what sort of compliance period is necessary to ensure a market for GOES and amorphous steel sufficiently robust and competitive to provide adequate supply to the distribution transformer market to allow manufacturers to meet demand at the efficiency standards adopted.

EEI commented that the proposed standards are in violation of EPCA because there is not a sufficient supply of amorphous metal capacity to replace GOES, making it likely that the available supply of compliant distribution transformers will be reduced. EEI stated that the conversion to amorphous will result in significant downtime for distribution transformer production lines, limiting production capacity in the near to medium term. (EEI, No. 135 at pp. 12–17) EEI added that the proposed standards will require significant changes across the entire value chain for distribution transformers, which raises concerns regarding the practicability of manufacturing and reliably installing and servicing amorphous core distribution transformers by the proposed effective date. (EEI, No. 135 at pp. 17–19) Portland General Electric commented that requiring amorphous metal transformers at a time when supplies are already severely constrained risks electric grid reliability, raising concerns regarding EPCA's requirement that DOE consider the availability of covered products and the practicability of manufacturing, installing, and servicing them. (Portland General Electric, No. 130 at p. 3)

DOE notes that the adopted standards allow for both GOES and amorphous transformers on the market. DOE estimates that the majority of distribution transformers (the entirety of equipment class 1B and 2B) will use GOES to meet the adopted standard (corresponding to over 140,000 metric tons of GOES steel in just the liquid-immersed distribution transformer market), while the remainder of the liquid-immersed distribution transformer market will use amorphous cores. Therefore, DOE has concluded that the adopted standards would not result in the unavailability of distribution transformers or negatively impact the distribution transformer supply chain.

Idaho Falls Power and Fall River both commented that a 3-year compliance period is too aggressive and recommended that DOE consider a longer compliance period, which allows efficiency goals to be completed through innovation and utilization of incentives. (Idaho Falls Power, No. 77 at p. 2; Fall River, No. 83 at p. 2). Pugh Consulting commented that DOE did not consider the length of time and costs required to meet the proposed standards by the 2027 compliance deadline. (Pugh Consulting, No. 117 at p. 3) Portland General Electric questioned whether the proposed standards can be met in a 3-year compliance period, given the array of changes likely to result from the proposed rule. (Portland General Electric, No. 130 at p. 4) LBA commented that the proposed timeline is insufficient for the industry to make the required changes, including redesigning factories, establishing a dependable supply chain, hiring a workforce, and redesigning infrastructure to accommodate a new variety of distribution transformer. (LBA, No. 108 at p. 3)

ERMCO commented that the timeline to meet the proposed standards will take longer than 3 years when considering the development of new supply chains, certification of new apparatus designs, and engagement of new manufacturing processes. (ERMCO, No. 86 at p. 1) Southwest Electric stated that converting to amorphous for entities that either supply or refine their own GOES appears to require more than the 3 years currently being allowed. (Southwest Electric, No. 87 at p. 3) Howard commented that transformer manufacturers will not be able to begin shipping amorphous transformers within 3 years because both amorphous and GOES manufacturers would need to construct new facilities and transformer manufacturers would need to invest in new equipment. (Howard, No. 116 at pp. 1–2, 16)

Powersmiths stated that January 2027 is too short a timeframe for the proposed standards due to how the technology change will disrupt existing manufacturing processes and supply chains. (Powersmiths, No. 112 at p. 2) Schneider commented that the market is not prepared for the proposed efficiency levels and more time is needed to explore the risks of product substitution, impact on other power distribution equipment, supply chain and capital investment, non-ideal capital solutions, and electric room/building impacts. (Schneider, No. 101 at pp. 2, 16)

DOE notes that the adopted standards include substantially lower conversion costs, as discussed in section IV.J of this document, and a longer compliance period, ensuring the energy savings associated with the amended standards can be achieved without negatively impacting the availability of distribution transformers.

While there was general agreement from stakeholders that a 3-year compliance period was insufficient for the majority of liquid-immersed and LVDT transformers to transition to amorphous cores, as was proposed in the NOPR, there were a variety of opinions as to what efficiency levels and timelines were achievable and would not exacerbate shortages or lead to significant increases in material costs.

Several stakeholders specifically recommended DOE delay any potential amendment of transformer standards until transformer prices and lead times return to historical averages.

ABB recommended that DOE create an interagency working group to focus on the increased production of GOES, amorphous metal, and other constrained materials. (ABB, No. 107 at pp. 3–4)

Eaton recommended DOE delay consideration of the NOPR until supply and demand for distribution transformers more closely aligns with historical levels. (Eaton, No. 137 at pp. 1–2) Southwest Electric recommended that the proposed standards be delayed until appropriate measures are taken to stabilize supply chains, including increasing the U.S. supplies of amorphous and copper, improving infrastructure for supporting heavier overhead transformers, and decreasing average lead times for liquid-filled transformers under 40 weeks. (Southwest Electric, No. 87 at p. 4) Howard commented that the timeline for proposed standards is too aggressive, reducing grid security by removing GOES, and making current supply chain issues more challenging. Accordingly, Howard encouraged DOE to delay implementation of standards based on the supply crisis and overly aggressive timeline. (Howard, No. 116 at p. 5)

DOE notes that an indefinite delay in efficiency standards violates DOE's statutory obligation to adopt the maximum increase in efficiency that is technologically feasible and economically justified (*See* 42 U.S.C. 6295(m)). The adopted standards are both technologically feasible and economically justified and do not pose substantial risk to the distribution transformer supply chain as discussed in section V.C of this document. The existing distribution transformer shortages are primarily associated with increased demand for grid products and shortages are unrelated to transformer efficiency. The adopted standards complement the efforts to resolve these shortages by allowing for significant flexibility in meeting efficiency standards such that energy savings can be achieved while also investing in additive transformer capacity that can diversify the core steel market and increase total transformer capacity.

Several stakeholders suggested that implementing efficiency standards that increased amorphous production could reduce the shortage concerns by shifting the distribution transformer market to amorphous material and freeing up GOES supply to be used in other applications or converted to NOES for EV applications.

Environmental and Climate Advocates commented that current transformer steel manufacturers are becoming increasingly focused on the EV market, creating greater reliance on electrical steel imports. Environmental and Climate Advocates stated that transitioning to amorphous could alleviate current GOES capacity constraints and will lead to a more robust long-term supply of distribution transformers since amorphous is not used in EV motors. Environmental and Climate Advocates also added that increasing capacity to amorphous production is relatively fast and inexpensive compared to adding GOES capacity. (Environmental and Climate Advocates, No. 122 at pp. 1–2)

Similarly, Efficiency Advocates and CEC commented that the proposed standards will help create a more secure long-term distribution transformer supply because amorphous does not experience competitive pressure from the electric vehicle market as GOES does. (Efficiency Advocates, No. 121 at p. 2; CEC, No. 124 at p. 2) Efficiency Advocates further commented that it is reasonable to expect that amorphous production would rapidly expand in response to standards given that adding amorphous ribbon capacity is less capital-intensive than adding GOES capacity. Efficiency Advocates added that there is a bias against amorphous due to transformer production being geared toward GOES, causing GOES transformers to be selected even in some instances when amorphous transformers are cheaper. Efficiency Advocates stated that the proposed standards would address this bias by spurring manufacturers to invest in producing amorphous transformers. (Efficiency Advocates, No. 121 at pp. 3–4)

DOE notes that the adopted standards include certain equipment classes that are expected to be met by transitioning to amorphous cores. Thereby, the adopted standards are likely to increase the number of domestic core steel suppliers serving the U.S. market from a single GOES producer to a mix of GOES and amorphous.

Several stakeholders suggested that DOE should establish revised efficiency standards where GOES steel will likely remain cost competitive and expand the compliance time to allow for more investment in GOES steel.

A group of U.S. Senators commented requesting that DOE finalize the proposed standards and extend the compliance date. The U.S. Senators stated that the proposed standards would provide Americans with significant savings on energy bills, but a longer compliance period is required to address current shortages and strengthen domestic supply chains. (U.S. Senators, No. 147 at pp. 1–2)

ERMCO suggested that DOE should either maintain current efficiency standards or propose standards at EL 2 or less, which would allow the U.S. supply chain to leverage both GOES and amorphous core steel supplies. ERMCO commented that this would allow sufficient time to validate the availability of raw materials, clarify load efficiency tradeoffs, and properly consider the total manufacturing investment. (ERMCO, No. 86 at pp. 1–2)

Sychak commented that Cliffs can supply lower-loss GOES grades but needs sufficient time to implement changes to its product mix. (Sychak, No. 89 at pp. 1–2) Sychak recommended DOE revise efficiency standards to allow for lower-loss GOES grades to remain cost competitive and revise the compliance date to 2030. (Sychak, No. 89 at pp. 1–2) Cliffs encouraged DOE to withdraw the proposed rule and meet with stakeholders to investigate alternative approaches, such as the possibility of producing higher-efficiency grades of GOES, given sufficient lead time to develop and manufacture these grades. (Cliffs, No. 105 at pp. 17–18)

Carte commented that GOES manufacturers are working to improve quality and the timeline of the proposed standards is very aggressive, not giving industry time to develop better GOES products. (Carte, No. 140 at pp. 3–4) Carte commented that future alloys will be able to maintain the durability of GOES and reduce eddy currents, but the proposed efficiency levels will inhibit this technology. (Carte, No. 140 at p. 4)

Carte recommended DOE delay standards until many of the concerns with amorphous are further investigated and work with industry to discuss what energy efficiency levels make sense. (Carte, No. 140 at p. 11)

MTC recommended DOE follow the lead of the European ECO–2 standards, which represent efficiency improvements over DOE's 2016 standards while allowing the use of GOES to ensure energy savings are cost effective. (MTC, No. 119 at pp. 16–17) MTC further recommended DOE delay amending efficiency standards for single phase transformers until experience with new core designs has been developed for three phase transformers similar to ECO–2. (MTC, No. 119 at p. 18)

DOE notes that the adopted standards include certain equipment classes that are at EL 2, as suggested by ERMCO, and are expected to be met with GOES cores. Further, the compliance period for amended standards has been extended, from the 3-year compliance period proposed in the January 2023 NOPR to a 5-year compliance period adopted in this final rule. The expanded compliance time also offers substantial opportunity for GOES manufacturers to increase production of lower-loss GOES products, as Sychak and Cliffs suggested.

Several other manufacturers recommended DOE move a portion of the market to amorphous and/or have expanded compliance dates in order to provide certainty that amorphous capacity will be sufficient and capital investment can be made without worsening near term transformer shortages.

CPI recommended that the final rule provide enough time for domestic transformer manufacturers to adjust to the proposed amorphous requirement without exacerbating current supply chain issues. (CPI, No. 78 at p. 1) CPI urged DOE to ensure that adequate sources of amorphous ribbon exist before the proposed rule becomes effective, suggesting that this could be achieved through a phased approach to the proposed rule. (CPI, No. 78 at p. 1)

Powersmiths and Eaton both commented that a tiered approach could be taken to implement efficiency standards with a more gradual impact to industry. (Powersmiths, No. 112 at p. 7; Eaton, No. 137 at p. 3)

Hammond commented that LVDT standards should not be amended because LVDTs already meet the most stringent efficiency requirements in the United States and Canada. However, Hammond stated that if DOE is going to amend efficiency standards, it recommends no higher than EL 3 for LVDTs. (Hammond, No. 142 at p. 3) Hammond also commented that the MVDT proposed standards are achievable and reasonable, especially given the proposed liquid-immersed levels. (Hammond, No. 142 at p. 3) DOE notes that Hammond's recommended efficiency levels correspond to efficiencies that could likely be cost effectively met using GOES.

Schneider stated that time would be needed to transition to amorphous in order to validate models, finalize footprint impacts, finalize capital requirements, and research impacts on sustainability, but supply chain constraints are inhibiting this research from being conducted via engineering samples. (Schneider, No. 92 at pp. 10–12) Schneider recommended that DOE establish the NOPR levels immediately as a voluntary ENERGY STAR level and delay the mandatory compliance date until January 1, 2030, to gradually convert the market toward new efficiency. Schneider stated this would provide manufacturers more time to evaluate technical impacts and establish supply chain partners. (Schneider, No. 92 at pp. 2, 16)

DOE notes that while a 3-year compliance period was proposed in the NOPR, stakeholder comment suggest that between 6 and 7 years would be needed to fully retool their production process to meet the proposed standards. WEG commented that between 5–7 years would be needed to retool their facility. (WEG, No. 92 at pp. 3–4) Schneider recommended mandatory compliance be delayed until 2030. (Schneider, No. 92 at pp. 2, 16) Sychak recommended DOE revise efficiency standards to allow for lower-loss GOES grades to remain cost competitive and revise the compliance date to 2030. (Sychak, No. 89 at pp. 1–2).

The timelines cited by stakeholders were generally based on the need to add substantially more amorphous core production capacity, as the January 2023 NOPR proposed EL4 for all liquid-immersed and EL5 for all low-voltage dry-type transformers. The standards adopted here, however, are expected to require less amorphous core production capacity. Accordingly, DOE anticipates that these lower efficiency standards could be achieved in fewer than the 7 years suggested by commenters. However, based on existing transformer shortages, DOE believes a 3-year compliance period may risk electrical steel prices increasing due to increased demand, which could result in exacerbating shortages in the near term. EPCA does not prescribe a specific time period for compliance with new or amended standards for distribution transformers.[135] Therefore, DOE has concluded that it is appropriate to extend the compliance period to 5 year to ensure sufficient time to allow investments in amorphous core production equipment, amorphous ribbon, and so that lower-loss GOES can be made without substantially increasing electrical steel prices. DOE further notes that a five-year compliance period is not uncommon for COMMERCIAL AND INDUSTRIAL equipment regulated under EPCA. *See generally,* 42 U.S.C. 6313.

As discussed, the adopted efficiency standards include different efficiency levels for different equipment classes as well as an expanded timeline, thereby providing certainty that amorphous capacity will be sufficient and capital investment can be made without worsening near term transformer shortages. DOE notes that existing capacity expansion announcements suggest that the near-term reaction to the January 2023 NOPR was to invest in amorphous in an additive capacity, given that additional distribution transformer production was needed anyway, as discussed in Chapter 3 of the TSD.

In evaluating whether higher efficiency standards would be met with GOES, DOE considers that, at baseline, most transformers are built with M3, as that is the predominant product sold by the single domestic GOES manufacturer. Lower-loss GOES exists and is included in DOE modeling; however, it generally has a price premium relative to M3 in the present market. As such, a transformer using lower-loss steel may be able to meet higher efficiency levels than a baseline M3 transformer using the same amount of steel (because the amount of losses per pound of steel are lower). However, because the lower-loss steel is sold at a price premium in the present market, the overall cost of that transformer may increase.

Howard commented that the primary barrier to using lower-loss GOES steels is supply related and manufacturers would use lower-loss GOES if tariffs were removed and domestic core manufacturers could import lower-loss GOES steel or domestic GOES manufacturers were incentivized to make lower-loss material. (Howard, No. 116 at p. 17) Howard commented that it produces its own cores domestically due to insufficient availability of lower-loss GOES material. (Howard, No. 116 at p. 17)

In the presence of amended standards, Cliffs, Sychak, and Howard suggested that existing producers of GOES may increase production of lower-loss GOES to meet the demand of the market or new producers of GOES may enter the market. If the increase in production capacity of this lower-loss GOES results in a reduction in the price premium, higher efficiency standards could be met without a transformer cost or size increase. For example, if the single domestic producer transitioned M3 grades to a lower-loss steel and did not increase the price per pound of GOES, higher efficiency standards (up to a point) could be met by building the exact same size transformers with the exact same costs and no required capital investment from distribution transformer manufacturers.

Schneider commented that as other countries require high grade dr core steel, lower quality hib and M-grade steels may become extremely cheap. (Schneider, No. 101 at p. 10)

Steel production tends to have volume-based efficiencies, wherein an initial transition to higher performing grades requires some degree of investment. However, once that investment is made and production is standardized on lower-loss steels, the incremental cost may decrease. DOE notes this sort of transitioning of core steel production was observed in response to the April 2013 Standards Final Rule. Prior to the compliance date of amended standards in 2016, baseline distribution transformers used a significant amount of M4, M5, or M6 core steel. 78 FR 23336. However, following the implementation of amended standards in 2016, the domestic GOES producer standardized on primarily M3 steel while many foreign producers standardized on hib and dr steels. These volume-based efficiencies resulted in a lower incremental cost between lower-loss GOES steel and M4, M5 or M6 grades. Not extremely cheap grades of these steels, as Schneider suggested.

For the current rulemaking, DOE's modeling indicates there is greater flexibility in transformer design, in terms of transformer size and core and coil design, when meeting amended standards with lower-loss GOES as compared to M3. Despite higher per pound prices, as higher-efficiency standards are evaluated, designing transformers with lower-loss core steel begins to achieve price parity with those designed with M3 steel, as the M3 designs typically operate at a reduced flux-density and add additional core material and/or use more (or more expensive) winding materials in order to meet higher efficiency standards, as demonstrated in Chapter 5 of the TSD. Whereas designs using lower-loss core steels can use a lesser amount of material to achieve the same efficiencies.

As stated by Howard, increased usage of lower-loss grades of GOES has traditionally been limited due to supply constraints on these steels which, in turn, contribute to a price premium on their market sale. (Howard, No. 116 at

[135] EPCA prohibits the application of new standards to a product with respect to which other new standards have been required during the prior 6-year period. 42 U.S.C. 6295(m)(4)(B). As noted earlier, however, the standards for distribution transformers were last amended in April 2013.

p. 17) In the past, the sole domestic producer of GOES has stated that it has the technical experience and ability to invest in additional grades of GOES as required by the market.[136]

Cliffs commented that they could produce higher-efficiency grades of GOES, given sufficient lead time to develop and manufacture these grades. (Cliffs, No. 105 at pp. 17–18) DOE notes that the adopted standards for liquid-immersed distribution transformers both extended the compliance period and adopted EL2 for equipment classes representing a substantial volume of shipments. Given Cliffs stated ability to manufacture lower-loss grades, expected demand for these grades into the future, the widespread existence of these grades in the global market, and the expanded compliance period by which these grades will be needed, it is expected that an increase in domestically produced lower-loss GOES grades will occur. As such, in the presence of amended standards, it is likely that the supply of higher grades of GOES would increase and, as a result of increased supply, the price premium that currently exists between M3 grades and higher grades of GOES would decrease.

Based on stakeholder feedback and historical GOES trends in the presence of amended efficiency standards, DOE has revised its pricing model for GOES in this final rule. In the no-new-standards case, DOE has continued to rely upon 5-year average pricing to develop base electrical steel prices. However, in the standards case, DOE revised its pricing for GOES for the liquid-immersed representative units to reflect an increased supply of low-loss GOES, as suggested by stakeholders. DOE notes that it is difficult to predict the exact investment and pricing strategy the domestic GOES manufacturer would employ. However, DOE assumed it would follow similar pricing dynamics to many of the foreign GOES suppliers that currently produce those steel grades. While the domestic GOES manufacturer could choose to follow different pricing dynamics, DOE notes that this would create considerable risk of losing market share to foreign GOES producers or the amorphous core market.

DOE modeled the price of 23hib090 at amended efficiency levels to match the price of baseline M3 grades. DOE notes these two products are sold for approximately the same price today (and, as discussed, foreign produced hib was less expensive than domestic GOES prior to tariffs), indicating that once manufacturers have invested in significant volumes of hib grades, they sell them at approximately equivalent prices to M3. For domain-refined grades, DOE reduced the price to a $0.10 cost-per-pound premium between 23hib090 grades and domain-refined grades. This premium aligns relatively well with the cost at which domain-refined grades become cost competitive with M3 grades at baseline, which stakeholders have noted is typical in the global market when sufficient supply is available.[137] This $0.10 cost-per-pound premium additionally accounts for the incremental production costs associated with the domain-refinement process.[138]

DOE notes that the domain-refinement process can be either an integrated process, such that domain-refined GOES is the direct output of production, or an independent additional processing step, wherein hib steel is separately treated to add domain-refinement. While the latter of these options requires additional floor space and capital investment, neither option has high input costs. As such, the material inputs required to produce domain-refined grades are not likely to lead to a significantly higher selling price once manufacturers have invested in the necessary production equipment. Rather, in the presence of sufficient supply, only a modest price premium is likely to exist between domain-refined and hib grades to account for the additional processing step required to add domain refinement to high permeability steel grades. Additionally, since domain refinement can occur as an independent processing step, it does not necessarily have to occur at the steel production site. While domain-refinement is typically conducted at the steel manufacturer sites, some manufacturers of domain-refinement equipment market the products for transformer core manufacturers to conduct their own laser scribing, which may be an option for large volume core manufacturers to minimize the cost-premium associated with domain-refined products, particularly if hib grades are available in sufficient volume domestically.[139]

These pricing updates reflect the fact that, in the no-new-standards case, steel manufacturers are likely to maintain the status quo. However, they also reflect stakeholder feedback that lower loss GOES pricing is largely demand dependent and would likely be reduced if GOES manufacturers invest in lower loss grades of GOES in the presence of amended standards, or if tariffs were lifted. Further, given the volume-based benefits of standardized production at a given steel grade, the price of these lower loss GOES materials may decrease as a result of increased production. Therefore, DOE evaluated any potential amended standards for liquid-immersed distribution transformers based on the reduced price of GOES that would be expected when compared to the no-new-standards case. Additional details on DOE's modelling of electrical steel pricing are provided in chapter 5 of the final rule TSD.

Additionally, as previously noted, DOE's modeling, as well as stakeholder comment, indicates that amorphous core transformer designs are already cost competitive with GOES core transformers for many transformer designs and would become even more favorable in the presence of amended standards, given the inherent improvement in no-load losses associated with amorphous cores as discussed in Eaton's comment. (Eaton, No. 137 at pp. 21–22). Therefore, at standard levels in which both GOES and amorphous metal can compete on a first cost basis, provided manufacturers make investment into amorphous core production equipment, it will be even more imperative for GOES producers to provide a supply of lower loss grades of GOES at a competitive price.

As discussed in section IV.F.3 of this document, DOE has also revised its assumptions to reflect transformer manufacturers' desire to not disrupt their existing GOES-core production capacity. Therefore, consumer amorphous core selection is limited through EL 2. The assumption limiting amorphous core selection is more likely to be valid the more cost- and performance-competitive GOES is. If there is a substantial increase in GOES core transformer cost, either resulting from a lack of investment in higher performing GOES steel or a substantial price premium for these lower loss GOES materials, customers would be

[136] (AK Steel, Docket No. BIS–2020–0015–0112 at pp. 7, 21).

[137] Central Moloney, a domestic manufacturer of distribution transformers, has commented that they purchase cores made of pdr steel for 90 percent of their designs. Indicating that if not subject to supply constraints, pdr can compete with M3 on first cost. See Docket No. EERE–2020–0015–0015.

[138] DOE notes that while pdr grades are modeled for liquid-immersed distribution transformers, there may be instances where dr grades can be used in certain wound core transformer designs without annealing, specifically if using a unicore production machinery. It is uncertain whether investments would be into pdr steel or dr steel as pdr steel typically requires greater investment (and therefore have a greater premium than dr steel) but would achieve greater loss reduction on account of annealing benefits.

[139] Castellini, *Laser Scribing Machine,* (Last Accessed 1/23/2024), Available online at: *https://www.castellini.it/products/solution/coil-processing/laser-scribing/*.

more likely to select amorphous transformer at EL 1 and EL 2.

For medium-voltage and low-voltage dry-type equipment classes, DOE did not similarly estimate a decrease in the price of higher grades of GOES as a result of amended efficiency standards because the dry-type market is served by a different supply chain than the liquid-immersed market. As discussed in section IV.A.4.b of this document, although both the liquid-immersed and dry-type markets may, in theory, be supplied by the same grades of core steel, the liquid-immersed market tends to be served first in practice due to its higher volume of shipments. As a result, since the dry-type market represents a smaller proportion of total distribution transformer shipments and, in turn, a smaller required core steel capacity, any changes to amended efficiency standards the dry-type market are less likely to significantly impact the electrical steel market or incentivize manufacturers to invest in higher grades of GOES. Further, even if standards were amended for the liquid-immersed market and the supply of higher grades of GOES were to increase as a result, the dry-type market would not necessarily experience the price-reduction benefits of these investments. Since core steel supply chains are established to serve the liquid-immersed market first, any investments in GOES capacity would likely be primarily directed towards the liquid-immersed market. As such, dry-type transformer manufacturers may be required to either continue to use M3 grades of GOES and meet amended efficiency standards via other design improvements or continue to pay a premium on higher grades of GOES in order to secure a supply chain over the liquid-immersed market. Therefore, for the reasons discussed, DOE only revised its GOES pricing model for the liquid-immersed representative units in this final rule and has continued to use 5-year averages (updated to reflect recent price changes between the January 2023 NOPR and final rule) to model electrical steel prices at all evaluated standard levels for the dry-type representative units.

Additionally, as discussed in sections IV.A.2.b and IV.A.2.c of this document, DOE has established separate equipment classes for liquid-immersed distribution transformers based on kVA rating. For certain equipment kVA ranges, levels were set at the NOPR efficiency levels, thereby assuring manufacturers that some portion of the market will likely be cost-effectively met by amorphous, and assuring amorphous ribbon manufacturers that capacity can be increased to meet expected increases in demand. However, for other kVA ranges, DOE walked back the efficiency levels such that GOES remains a very cost-competitive option, even if standards may be more cost-effectively met with amorphous. As such, manufacturers will continue to have the design flexibility to decide which core material to utilize. Lastly, distribution transformer capital equipment is capable of producing a wide array of kVA ranges. Hence, existing GOES equipment can focus on levels that are more cost-effectively met with GOES while additive amorphous equipment can focus on levels that are more cost-effectively met with amorphous. Additionally, DOE has expanded the compliance period, such that transformers do not have to meet any higher efficiency levels for 5 years, ensuring additional time for these investments.

Taken together with an expanded compliance period, the standards adopted here will give GOES manufacturers, amorphous manufacturers, and distribution transformer manufacturers sufficient time and market certainty to make investments in both GOES and amorphous such that, prices will remain in line with DOE's modeling across a range of all reasonable manufacturer choices and efficiency standards will not make existing distribution transformer shortages worse. Further, DOE believes at least some additional portion of the market is likely to be met via amorphous ribbon, meaning the U.S. distribution transformer core market will likely be served in considerable volume by at least two domestic manufacturers, one for amorphous and one for GOES—as compared to today, wherein nearly all of the domestic market is served by a single domestic GOES manufacturer. A more diversified domestic supply ensures that uncertainty in policy decisions, such as implementation of tariffs, have less of an impact on domestic producers of distribution transformers.

In the economic analysis for distribution transformers, DOE models consumer purchases for baseline distribution transformers based on the current market trends, whereby a utility customer purchases the lowest cost distribution transformer that uses existing widely produced core steels, as discussed in section IV.F.3.a of this document. At EL1 and EL2 for liquid-immersed distribution transformers, DOE's analysis continues to model that distribution transformer manufacturers will choose to maintain their existing GOES equipment in order to avoid the investments needed to upgrade their production facilities to accommodate more-efficient types of steel used to make more-efficient distribution transformers. Therefore, DOE models consumers as purchasing GOES-core distribution transformers, even if amorphous-core transformers would be lower first-cost. Starting at EL3, DOE assumes liquid-immersed distribution transformer customers purchase the lowest cost distribution transformer that meets the evaluated efficiency level and therefore generally assumes most of that market transitions to amorphous cores. DOE assumes manufacturers begin shift to amorphous at EL 3 by making investments to upgrade their distribution transformer production facilities to accommodate amorphous steel, even though they would not at lower levels. Even though EL 3 can be met with more efficient GOES, manufacturers may choose to use amorphous steel to make distribution transformers cores because it is more economical. DOE considers various Trial Standard Levels as discussed in section V.A of this document; TSL 4 and above include all equipment classes at EL 4 and above, while TSL 3, the amended standard level, includes only equipment class1A and 2A at EL 4 (with the remaining classes at EL 2), resulting in only 48,000 metric tons of amorphous usage. That level of amorphous steel usage is not expected to impact the current domestic steel market given the existing domestic capacity and announced amorphous capacity expansions.

As discussed, amended standards could increase or decrease the demand for certain grades of GOES and amorphous steels that are used in cores to make more-efficient distribution transformers. To the extent that these shifts in market shares across raw material sources are large, such as in the case of TSL 4, it is possible that shifts in demand could change the underlying steel prices if supply cannot accommodate the demand increases. The pricing dynamics of the electric steel market are complicated given the global market dynamics, tariff structures and the modernization of the U.S. electric grid to help support resilience. DOE's adopted standard level accounts for these dynamics by setting efficiency levels which, based on the assumptions and data discussed above, are expected to maintain the demand for domestic GOES while beginning to grow the demand for amorphous steel in a managed transition that allows time for businesses and the workforce to gain experience, familiarity, and confidence in amorphous core distribution transformers.

Beyond any endogenous effect on steel demand—and price—resulting from the standards adopted in this rule, demand for electrical steel could be further heightened by efforts across the country to electrify building end-uses and transportation, including government initiatives, through legislation and rulemakings, outside the scope of this document. As one example, the proposed rulemaking by EPA on emissions standards for light duty vehicles projects that electricity demand will increase by 4.2% in 2055 as a result of that rule.[140] In this rulemaking, for the reasons explained above, DOE models an increase in distribution transformer shipments annually, which results in a 0.7-percent increase annually or approximately 75,000 units. These estimates are derived from AEO2023's growth rate to account for the increase in electricity demand resulting from various electrification policies and standards across the United States. DOE's use of AEO 2023 projections to drive its future shipments (and stock) growth result in a 190-percent increase in total installed stock (in terms of capacity) by 2050 as compared to a 2021 baseline. A report[141] by the National Renewable Energy Laboratory estimates future growth in stock between 160 and 260 percent by 2050 for distribution transformers, including step-up transformers which are not in the scope of DOE's rulemaking, but it shows consistent projections regarding future growth. DOE also ran higher and lower growth sensitivities, which were developed from the high and low scenarios in AEO 2023.[142] Lastly, DOE presents in appendix 10C of the TSD a sensitivity scenario examining the impacts of utilities installing larger distribution transformers (increased per unit average capacity) in response to growing decarbonization/electrification initiatives. These are all further detailed in section VI.E.3.a of this document. If these electrification increases are not adequately captured by *AEO 2023* energy usage projections and sensitivities, DOE may be underestimating the demand for electricity–and therefore distribution transformers–in the analysis.

An additional pricing consideration within the market for distribution transformers is the role of competition and market structure. As elsewhere discussed in this document, GOES and amorphous demand in the United States are each supplied by one (separate) domestic producer. Existing foreign supply sources for amorphous alloy is limited to one producer in Japan, as well as several producers in China. As mentioned earlier, DOE does not expect the adopted standard level to alter the demand for GOES, in addition to the estimated efficiency benefits that amorphous steel transformers provide, DOE further believes that shifting some demand to amorphous steel might on the margin alleviate existing supply chain issues with GOES core transformers that was the source of extensive stakeholder feedback in response to the NOPR. While the increase in demand for amorphous alloy caused by today's standard might encourage additional entrants into the supply chain, it is worth considering the resulting market structure for amorphous alloy suppliers should all new demand be serviced only by existing producers.

At TSL 4, the demand for amorphous cores is projected to be approximately equal to today's global capacity of amorphous alloy. In the short term, an inability for suppliers to scale production and manufacturers to retool production lines towards amorphous core distribution transformers could lead to short-term market disruptions. If amorphous demand is serviced by the domestic manufacturer of amorphous alloy and tariffs remain in place, this introduces a possibility for a shift towards monopoly markups absent price competition. If foreign supply or additional domestic entrants for amorphous alloy are available, these monopoly markup issues can be somewhat mitigated. For example, in an alternative energy industry context it has been empirically shown that duopoly markups are lower than economic theory might otherwise predict, due to issues associated with protecting against additional market entrants and imperfect information.[143]

DOE acknowledges the above issues with respect to this rulemaking's potential impact on prices, and further acknowledges the complexity of accurately modeling price responses to regulations. To address the aforementioned concerns with endogenous price changes as a consequence of the rulemaking, as well as increased demand resulting from exogenous policy changes, in lieu of a market structure analysis, DOE has adopted standards that DOE expects to require an increase in amorphous demand that can be met with much higher probability in the revised 5-year compliance window. DOE has determined that such standards achieve the greatest energy savings that are economically justified. That is so even though DOE estimates consumer benefits would be maximized under the TSL4 standard that requires additional amorphous steel. However, based on these market-structure concerns, DOE has determined such standards are economically justified at this time.

General considerations for price responses and market structure are areas DOE plans to explore in a forthcoming rulemaking action related to the agency's updates to its overall analytic framework.

For TSL 3, DOE assumes that for the 1A and 2A equipment classes where DOE has proposed efficiency level 4, all future demand for distribution transformers will likely be met be met by amorphous cores. However, at TSL 3 for all other liquid-immersed equipment classes where DOE has proposed efficiency level 2, DOE assumes minimal amorphous core production even where amorphous is the lower first-cost product. In the long-run, it is possible that amorphous alloy supply will adequately increase to meet the new demand and will increase adoption of amorphous even for segments of the market that subject to standards that could be met with GOES cores. In that scenario, consumer and energy savings may be even greater than those modeled in this analysis. However, for distribution transformers, given the acute shortages this market has experienced in the past several years and the resulting higher prices, DOE has accounted for stakeholder feedback that total conversion from GOES to amorphous is not feasible in the short-term. Therefore, DOE has adopted a TSL that reflects the extensive feedback and data supplied to the rulemaking record that is economically justified and technologically feasible.

b. Other Material Prices

Regarding other materials used in a distribution transformer, DOE similarly relies on 5-year average costs for materials and includes labor costs derived largely from public indices, markup costs, and transportation costs.

[140] 88 FR 29184. Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles. May 5, 2023.

[141] K. McKenna et al: Major Drivers of Long-Term Distribution Transformer Demand, Feb 2024, NREL/TP–6A40–87653.

[142] See appendix 10B of the TSD. National Impacts Analysis Using Alternative Economic Growth Scenarios.

[143] Wolfram, Catherine. Measuring Duopoly Power in the British Electricity Spot Market. American Economic Review. 89 (4) 805–826. 1999.

DOE detailed all of these costs in chapter 5 of the NOPR TSD.

Regarding these costs, Idaho Power commented that the metal price indices used by DOE are appropriate, but recommended DOE consider labor and transportation costs. (Idaho Power, No. 139 at p. 4) Pugh Consulting commented that DOE did not properly account for the impact of labor shortages. (Pugh Consulting, No. 117 at p. 3)

Regarding labor requirements, Georg commented that automation can reduce the labor-intensive work associated with transformer production and stated that Georg offers solutions to automate wound core production for both GOES and amorphous cores and stacked GOES cores. (Georg, No. 76 at p. 1)

DOE notes that Idaho Power did not suggest an alternative method for considering labor or transportation costs. As noted in the January 2023 NOPR, DOE applies a labor cost per hour that is generally derived from the U.S. Bureau of Labor Statistics rates for North American Industry Classification System (NAICS) Code 335311—''Power, Distribution, and Specialty Transformer Manufacturing'' production employees hourly rates and applies markups for indirect production, overhead, fringe, assembly labor up-time, and a non-production markup to get a fully burdened cost of labor. 88 FR 1722, 1768. DOE has updated these labor rates, which reflect the recent increase in labor costs as discussed in chapter 5 of the TSD.

Regarding other materials costs, DOE notes that the majority of materials in a distribution transformer, aside from the transformer core, are commodities used across many products.

Southwest Electric stated that it predicts a 47.5-percent average increase in copper weight to meet the proposed standards and expressed concern that this increased demand will both increase the cost of copper and lead to potential shortages. (Southwest Electric, No. 87 at p. 3) Southwest Electric commented that the 5-year average price of copper is much lower than the current price of copper and therefore DOE should update its cost models to reflect the more likely costs from 2023–2027, rather than incorporating the discounted prices that existed between 2017–2021. (Southwest Electric, No. 87 at p. 3) Southwest Electric further recommended that DOE correct its cost model before finalizing a standard to reflect the direct cost increases associated with rising metal prices and the indirect cost increases associated with transporting, supporting, and repairing heavier overhead transformers. *Id.*

Powersmiths commented that copper will be required to meet many efficiency standards, which is more expensive, volatile, and subject to substantial competing demand to meet efficiency standards. Accordingly, Powersmiths encouraged DOE to set efficiency levels that can be met with aluminum windings. (Powersmiths, No. 112 at p. 3)

WEG commented that the supply of copper is limited and higher standards will drive more need for copper material vs aluminum. (WEG, No. 92 at p. 2) Eaton recommended that DOE consider the risk of reduced copper availability over the next two decades. (Eaton, No. 137 at p. 29) HVOLT commented that many designs will need to convert to copper windings in a time when copper is in tight supply. (HVOLT, No. 134 at p. 8) Carte commented that 20-percent additional conductor material would also have environmental and supply chain impacts. (Carte, No. 140 at p. 2)

Howard commented that copper usage will likely increase, making it more difficult for manufacturers to obtain. Howard added that, while other materials like oil, transformer tank steel, and insulating paper likely will not face significant shortages in the presence of amended standards, the quantity of these materials used will increase, thereby increasing the transformer MSP. (Howard, No. 116 at p. 24)

DOE notes that copper is used in a variety of industries and with a variety of electrical products. Hence, the distribution transformer market does not singularly dictate the supply and demand dynamics that impact the price of copper. DOE has used common indexes to determine the 5-year average price of copper. Further, DOE notes that the adopted efficiency levels for liquid-immersed distribution transformers can be met with GOES cores and aluminum windings for the equipment classes set at EL2 and with amorphous cores and aluminum windings for the equipment classes set at EL4. Low-voltage dry-type and medium-voltage dry-type transformer efficiency levels can also be met with GOES cores and aluminum windings.

Southwest Electric commented that, although a more efficient transformer allows manufacturers to reduce the amount of radiators required, the reduction is not enough to offset the material and labor increases needed to reach those efficiencies. (Southwest Electric, No. 87 at p.2)

Regarding transportation and labor costs, Schneider commented that DOE should consider the climate costs associated with increased transportation costs if the size of LVDTs increases. (Schneider, No. 101 at p. 11) Multiple commenters stated that larger transformers, and specifically amorphous core transformers, will require more truckloads to deliver the same number of transformers and additional weight will increase fuel costs, which DOE should account for in additional transportation costs. (ERMCO, No. 86 at p. 1; Powersmiths, No. 112 at p. 3; Idaho Power, No. 139 at p. 6; Eaton, No. 137 at p. 41)

Regarding transportation costs, DOE noted in the January 2023 NOPR that it uses a price per pound estimate for the shipping cost of distribution transformers. 88 FR 1722, 1768–1769. This methodology means that transformers with increased weight will have increased shipping costs reflected in DOE's analysis. DOE understands that the cost to ship each unit will vary depending on weight, volume, footprint, order size, destination, distance, and other, general shipping costs (fuel prices, drive wages, demand, etc.). DOE has previously sought comment as to whether this cost-per-pound accurately models the complexity of distribution transformer shipping costs. *Id.*

In response, Eaton commented that shipping costs vary, but DOE's shipping cost estimates are reasonable. (Eaton, No. 55 at p. 16) DOE did not receive comments suggesting that its cost-per-pound to ship transformers is inaccurate, or any suggestions as to how to model the complexity of distribution transformer shipping costs more accurately. Therefore, DOE retained its cost-per-pound shipping methodology described in chapter 5 of the TSD.

The resulting bill of materials provides the basis for the manufacturer production cost (MPC) estimates.

To account for manufacturers' non-production costs and profit margin, DOE applies a multiplier (the manufacturer markup) to the MPC. The resulting manufacturer selling price (MSP) is the price at which the manufacturer distributes a unit into commerce.

DOE's average gross margin was developed by examining the annual Securities and Exchange Commission (SEC) 10–K reports filed by publicly traded manufacturers primarily engaged in distribution transformer manufacturing and with a combined product range that includes distribution transformers. For distribution transformers, DOE applied a gross margin percentage of 20 percent for all distribution transformers.[144]

In the January 2023 NOPR, DOE acknowledges that while some manufacturer may have higher gross

[144] The gross margin percentage of 20 percent is based on a manufacturer markup of 1.25.

margins, the gross margin is unchanged from the April 2013 Standards Final Rule and was presented to manufacturers in confidential interviews as part of both the preliminary analysis and the NOPR analysis and there was general agreement that a 20-percent gross margin was appropriate for the industry. 88 FR 1722, 1769. DOE has retained the 20-percent gross margin as part of this analysis.

3. Cost-Efficiency Results

The results of the engineering analysis are reported as cost-efficiency data (or ''curves'') in the form of energy efficiency (in percentage) versus MSP (in dollars), which form the basis for subsequent analyses in the final rule. DOE developed 19 curves representing the 16 representative units. DOE implemented design options by analyzing a variety of core steel material, winding material, and core construction methods for each representative unit and applying manufacturer selling prices to the output of the model for each design option combination. *See* chapter 5 of the TSD for additional details on the engineering analysis.

DOE then relies on these cost-efficiency curves and models consumer choices in the presence of various amended efficiency levels to calculate the downstream impacts of each theoretical efficiency standard. In general, DOE's analysis assumes most distribution transformer customers purchase based on lowest first cost and there is limited market above minimum efficiency standards (*see* section IV.F.3 of this document).

D. Markups Analysis

The markups analysis develops appropriate markups (*e.g.,* retailer markups, distributor markups, and contractor markups) in the distribution chain and sales taxes to convert the MSP estimates derived in the engineering analysis to consumer prices, which are then used in the LCC and PBP analysis. At each step in the distribution channel, companies mark up the price of the product to cover costs. DOE's markup analysis assumes that the MSPs estimated in the engineering analysis (*see* section IV.C of this document) are occurring in a competitive distribution transformer market as discussed in section V.B.2.d of this document.

As part of the analysis, DOE identifies key market participants and distribution channels. For distribution transformers, the main parties in the distribution chain differ depending on purchaser and on the variety of distribution transformer being purchased.

For the January 2023 NOPR, DOE assumed that liquid-immersed distribution transformers are almost exclusively purchased and installed by electrical distribution companies; as such, the distribution chain assumed by DOE reflects the different parties involved. 88 FR 1722, 1769. DOE also assumed that dry-type distribution transformers are used to step down voltages from primary service into the building to voltages used by different circuits within a building, such as plug loads, lighting, and specialty equipment; as such, DOE modeled that dry-type distribution transformers are purchased by non-residential customers (*i.e.,* COMMERCIAL AND INDUSTRIAL customers). *Id.*

DOE considered the following distribution channels in Table IV.7.

Table IV.7 Distribution Channels for Distribution Transformers

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

DOE did not receive any comments on the distribution channels applied in the NOPR and maintains the same approach in this final rule.

Chapter 6 of the final rule TSD provides details on DOE's development of markups for distribution transformers.

E. Energy Use Analysis

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

As presented in section IV.A.3, transformer losses can be categorized as ''no-load'' or ''load.'' No-load losses are roughly constant with the load on the transformer and exist whenever the distribution transformer is energized (*i.e.,* connected to electrical power). Load losses, by contrast, are zero when the transformer is unloaded, but grow quadratically with load on the transformer.

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

1. Trial Standard Levels

As discussed in detail in section V.A of this final rule, DOE typically evaluates potential new or amended standards for products and equipment by grouping individual efficiency levels for each class into TSLs. Use of TSLs allows DOE to identify and consider manufacturer cost interactions between the equipment classes, to the extent that there are such interactions, and price elasticity of consumer purchasing decisions that may change when different standard levels are set. For this analysis, as in the NOPR, DOE applied a Purchase Decision model (*See* section IV.F.3 of this document) to simulate the process that consumers use to purchase their equipment in the field within the LCC and PBP analysis (*See* section IV.F of this document). To conduct these analysis DOE must know the composition of potential amended standards (TSL) as an input as they represent the purchasing environment to consumers under amended standards. The results that follow are presented by TSL to capture the consumer, national, and manufacturer impacts under the amended standards scenarios considered by DOE.

2. Hourly Load Model

For utilities, the cost of serving the next increment of load varies as a function of the current load on the system. To appropriately estimate the cost impacts of improved distribution transformer efficiency in the LCC analysis, it is therefore important to capture the correlation between electric system loads and operating costs and between individual distribution transformer loads and system loads. For this reason, DOE estimated hourly loads on individual liquid-immersed distribution transformers using a statistical model that simulates two relationships: (1) the relationship between system load and system marginal price; and (2) the relationship between the distribution transformer load and system load. Both are estimated at a regional level. Distribution transformer loading is an important factor in determining which varieties of distribution transformer designs will deliver a specified efficiency, and for calculating distribution transformer losses, and the time-dependent values of those losses. To inform the hourly load model, DOE examined data made available through the IEEE Distribution Transformer Subcommittee Task Force (IEEE TF).

DOE received the following comment regarding the loading of liquid-immersed distribution transformers: Carte questioned if DOE's analysis considered the wide range of loads that transformers serve in the field and whether DOE considered periods of high loading and low loading as part of its simulation. (Carte, No. 140 at p. 7) Central Hudson Gas and Electric (CHG&E) commented that it attempts to size its transformers at 80-percent of their nameplate capacity on new installations, and that some of its transformers are loaded at almost 200-percent of their nameplate rating. (CHG&E, Public Meeting Transcript, No. 75 at pp. 92–93) Metglas commented that an IEEE TF on Loading revealed that there is less than a 20-percent load on most transformers—well below the 50-percent loading test condition. Metglas added that it has heard from multiple utilities and OEMs that oversizing transformers is common and that, due to this fact, the actual loading is likely to remain around 20 percent. (Metglas, No. 125 at pp. 4, 7) Idaho Power commented that it supports DOE's application of an hourly load model for liquid-immersed distribution transformers. (Idaho Power, No. 139 at p. 4)

In response to CHG&E, DOE assumes CHG&E is referring to its customers' maximum peak demand, and maximum peak demand is not the average load on the distribution transformer. DOE loading analysis accounts for occurrences where the distribution transformers are loaded at a high percentage of their nameplate. While the overloading that CHG&E describes is discussed in IEEE C57.91–2011 as acceptable practice, DOE understands that overloading is the exception and not the rule as, depending on seasonality, the additional heat accumulated in the distribution transformer on high-temperature peak days can be detrimental to distribution transformer insulation lifetimes, potentially resulting in premature replacement. This strategy may be beneficial to CHG&E given its operational cost structures, but runs counter to DOE's understanding that utilities strive to reduce the cost of operation.

In response to CHG&E, Carte, Idaho Power, and Metglas, DOE's hourly load simulation, as discussed in the January 2023 NOPR, was designed specifically to account for the wide range of loads seen in the field, and for non-linear impacts on load losses when the transformer is under high loads. 88 FR 1722, 1770–1772. To do so, DOE used a two-step approach. Transformer load data were used to develop a set of joint probability distribution functions (JPDF), which capture the relationship between individual transformer loads and the total system load.[145] The transformer loads were calculated as the sum load of all connected meters on a given transformer for each available hour of the year. Because the system load is the sum of the individual transformer loads, the value of the system load in a given hour conditions the probability of the transformer load taking on a particular value. To represent the full range of system load conditions in the United States, DOE used FERC Form 714 [146] data to compile separate system load PDFs for each census division. These system PDFs are combined with a selected transformer JPDF to generate a simulated load appropriate to that system. As the simulated transformer loads are scaled to a maximum of one to calculate the losses, the load is multiplied by a scaling factor selected from the distribution of Initial Peak Loads (IPLs), and by the capacity of the representative unit being modeled. In the August 2021 Preliminary Analysis, DOE defined the IPL as a triangular distribution between 50 and 130 percent of a transformer's capacity, with a mean of 85 percent. This produces an hourly distribution of PUL values from which hourly load losses are determined. These distributions of loads capture the variability of distribution transformers load diversity, from very low to very high loads, that are seen in the field. The comments received did not provide data or evidence beyond anecdotal statements for DOE to change the modeling assumptions in the NOPR; as such, this distribution was maintained from the NOPR in this final rule.

APPA commented that amorphous transformers are larger and more expensive, but the expense does not rise

[145] *See* Distribution Transformer Load Simulation Inputs, Technical Support Document, chapter 7.

[146] Available at *www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.*

linearly with the capacity of the transformer. APPA commented that higher capacity transformers are cheaper per kW than smaller ones, so to save money, it is only logical that where shared secondary cable already exists, one should replace two or more (smaller capacity) transformers with a single (larger capacity) transformer and combine the shared portion of the secondary network. APPA commented that this has been shown to increase losses in the shared secondary cable to between 0.6 and 2.2 percent of total power delivered, far outstripping the increased efficiency of the amorphous transformer. APPA added that although DOE could consider working with utilities on secondary issues for more efficiency, the NOPR's analysis does not adequately account for this issue, which would undercut the efficiency conclusions in the proposed rule. (APPA, No. 103 at p. 15)

Regarding the APPA comment, when DOE conducts its analysis, it compares the costs and benefits of a revised standard against the no-new standards case. APPA's scenario asserts that at the time of transformer replacement, ''it is only logical that . . . banks of distribution transformers should be replaced with a single,'' DOE assumes a larger-capacity distribution transformer to optimize the cost per unit capacity of service being delivered. The lack of information provided by APPA makes it impossible for DOE to respond technically to this assertion; DOE notes that any single-unit replacement of multiple-unit installations would need to be sized in terms of capacity to meet the aggregate maximum demand of all connected customers (plus any safety margins) on said circuit. APPA's comment asserts that additional losses on the secondary is a function of equipment aggregation—a decision made at the individual utility's operational level, and, as described by APPA, is an example of a utility favoring operational efficiency over energy efficiency, which would happen in the absence of a revised standard by DOE and, as such, is not considered in this final rule.

a. Low-Voltage and Medium-Voltage Dry-Type Distribution Transformers Data Sources

Idaho Power commented it believes the base data used in the April 2013 Standards Final Rule was scaled from 1992 and 1995 data, and there have been many energy efficiency standards that have been incorporated over the last 30 years. Idaho Power recommended that DOE consider updating the standard to reflect current loading data and include advanced data collection methods that provide more granular data. Idaho Power added that many power companies have automated meter read data that could be leveraged for better analysis. (Idaho Power, No. 139 at p. 5)

DOE agrees with Idaho Power's comments that since the CBECS last included monthly demand and energy use profiles for respondents in 1992 and 1995 editions that many energy efficiency standards have been promulgated. For its dry-type analysis, DOE used the hourly load data for COMMERCIAL AND INDUSTRIAL customers from data provided to the IEEE TF (from 2020 and 2021) to scale these monthly values in its loading analysis for low-, and medium-voltage dry-type distribution transformers (*see* chapter 7 of this final rule TSD). DOE is aware that many utilities meter their customers using real-time meters; however, DOE does not have the authority to demand such data from said utilities. Instead, DOE must rely on such industry initiatives such as the IEEE TF or individual companies to voluntarily come forward with data.

3. Future Load Growth

a. Liquid-Immersed Distribution Transformers

Several commenters stated their concerns over the possibility that future loads would rise on distribution transformers as a result of increased electrification. While no single commenter provided data or projections (simulated or otherwise) to support this concern, some commenters did hypothesize that liquid-immersed distribution transformer loads may grow in the future. (Mulkey Engineering, No. 96 at p. 1; Cliffs, No. 105 at pp. 12–13; HVOLT, No. 134 at pp. 3–4; WEG, No. 92 at p. 3; Idaho Power, No. 139 at p. 2)

Metglas commented that electrification impacts on distribution transformers would be uncertain. Metglas commented that electrification is likely to increase in response to global decarbonization goals. However, Metglas added that efficiency improvements in HVAC units, electric lighting, and other areas have kept the demand for electricity consumption essentially flat since 2010. The proposed DOE efficiency regulations will also help to decrease loading on the grid. (Metglas, No. 125 at p. 4)

CEC commented that electrification is increasing energy demands, with demand expected to increase by nearly 29 percent by 2035. CEC noted that increasing transformer efficiency would help reduce demand on the grid, but recommended DOE closely examine technical, cost, and reliability issues because of the unique risk that transformers pose to broader electrification trends. (CEC, No. 124 at pp. 1–2)

HVOLT and WEG commented that based on information supplied by EIA, total (net) generation had grown at a rate of 3.3 percent between 2021 and 2023. (HVOLT, No. 134 at pp. 3–4; WEG, No. 92 at p. 3) Further, APPA questioned DOE's use of EIA's AEO projection of future delivered electricity, stating that other trends suggest potentially much higher rates of electric end-use consumption, and citing President Biden's Executive Order No. 14037, which calls for 50 percent of all new passenger cars and light trucks sold in 2030 to be zero-emission vehicles. APPA commented that there are a wide variety of projections of electric vehicle sales by 2030, and EV sales already reached nearly 6 percent of all new car purchases in 2022, and that share is only expected to increase. Additionally, APPA commented that Federal and State governments are mandating that homes and buildings be electrified to cut emissions. (APPA, No. 103 at p. 5) NYSERDA commented that EIA forecasts of electricity demand do not reflect the significant demand increases anticipated in New York and other parts of the country due to aggressive decarbonization policies and accelerating rates of EV adoption. As such, NYSERDA anticipates DOE has underestimated the potential energy-saving impact of these standards, underscoring the need to complete this rulemaking as quickly as possible. (NYSERDA, No. 102 at pp. 1–2) Carte commented that EIA's loading appears to be based on history and not forward looking, which could explain why such a low increase in loading is predicted. Carte commented that electrification does not appear to be considered when talking about 0.9 percent increases per year. (Carte, No. 140 at p. 6)

Further, APPA commented that with electric vehicles, solar photovoltaic, building decarbonization, and other energy transition technologies, the average household will move from an average load of 2 kW to an average of 6 kW and a peak of 5 kW to a peak of 10 to 25 kW (with range based on EV sizing). APPA commented that currently, 25 kVA transformers serve two to six residences, and transformers are going to see at least twice the load, with fewer low/no load hours. APPA commented that an economic justification analysis for the proposed distribution transformer efficiency standards would need to address the change in the way transformers will operate during and after the transition and analyze how NOES transformer efficiency will be impacted by these changes, and whether those changes impact the NOPR's cost/benefit analysis. (APPA, No. 103 at p. 17)

Regarding HVOLT and WEG's comment about net generation growth, DOE notes that net generation cannot be used as a proxy for distribution transformer loads.[147] Net generation is a ''top-down'' indicator of how much generation is required to meet ''bottom-up'' demands of electrical consumption (purchases) and must account for generating capacity to meet total peak generation, reserve margins, the capacity factors of each variety of generating unit, and transmission losses, plus unavailable capacity (outages).[148] [149] [150] DOE finds that EIA's changes in projected purchased electricity to the final consumer represents a more appropriate proxy for distribution transformer load growth due to the distribution system's physical proximity to the final electrical consumer. For this final rule, DOE has continued to use AEO's projection of Energy Use: Delivered: Purchased Electricity, noting that the rate has changed from that in the NOPR to 0.7 percent per year in this final rule.[151]

APPA's comments to DOE did not suggest any specific alternative trends that would suggest potentially much higher rates of electric end-use consumption in place of AEO. As discussed later in this section, DOE applies the rate of load growth over its entire analysis period resulting in a significant growth of 22 percent, which results in positive consumer benefits for all liquid-immersed equipment at today's amended standard levels (*see broadly:* section V) Additionally, as specified in 10 CFR part 431, subpart K, appendix A certification of medium-voltage liquid-immersed distribution transformers must occur at 50 percent PUL—a rate that ensures efficient load-loss performance over a wide range of loads, both low and high. If loads were to grow at a rate greater than that estimated by AEO, the standard adopted by DOE would result in greater energy savings, and consumer and National benefits.

Further APPA, NYSERDA, and Carte commented that future loads would be driven by increased EV adoption, claiming that EV adoption is not included in AEO's total purchase electricity projection. DOE's examination of *AEO2023,* Table 2, Energy Consumption by Sector and Source, shows purchased electricity to transportation (including light duty vehicles) to increase at a rate of 9.7 percent per year.

Idaho Power commented that it expects residential loads to increase 10 to 25 percent; however, no time period for this increase was provided. (Idaho Power, No. 139 at p. 2) Xcel Energy commented that with increased electrification, it expects an increase in load factor and a higher rate of changeouts (to larger-capacity units). (Xcel Energy, Public Meeting Transcript, No. 57 at p. 133) WEC commented that it projected that loading would increase by 5 to 15 percent on its single-phase distribution transformers; again, no period over which this would occur was provided. (WEC, No. 118 at p. 1) Carte commented that increased adoption of EVs and other electrification technologies will greatly increase transformer loads. (Carte, No. 140 at pp. 5–6) Further, Carte and CARES expressed a belief that loads will grow by 50 percent, a number that they attribute to EEI without citation. (Carte, No. 140 at p 6; CARES, No. 99 at p. 4)

Specifically, in response to the assertions from Carte and CARES that loads will grow by 50 percent over the next 5 to 10 years, DOE has identified a presentation that is believed to be the source document of these values; [152] the presentation forecasts that the range of electric loads increase will ''vary wildly, anywhere from 5 and 50 percent, depending on multiple factors,'' indicating that 50 percent is a maximum bound of EEI's load growth estimate—not the likely outcome indicated by Carte and CARES.

As stated in the January 2023 NOPR, and evidenced by the comments received, many factors potentially impact future distribution transformer load growth, and these factors may be in opposition. At this time, many utilities, States, and municipalities are pursuing EV charging programs, and it is unclear the extent to which increases in electricity demand for EV charging or other State-level decarbonization efforts, will impact current distribution transformer sizing practices (for example, whether distribution utilities plan to upgrade their systems to increase the capacity of connected distribution transformers, thus maintaining current loads as a function of distribution transformer capacity; or if distribution utilities do not plan to upgrade their systems and will allow the loads on existing distribution transformers to rise). DOE recognizes that this is further complicated by the current supply shortage of distribution equipment. Some stakeholders speculate that these initiatives will increase the intensive per-unit load over time as a function of per unit of installed capacity. However, these stakeholders did not provide any quantitative evidence that this is indeed happening on their distribution systems, or in regions that are moving forward with decarbonization efforts. Further, the hypothesis that intensive load growth will be a factor in the future is not supported by available future trends in *AEO2023,* as indicated by the purchased electricity trend representing the delivered electricity to the customer. Others asserted that higher loads in response to decarbonization initiatives would be met with the extensive growth of the distribution system (*i.e.,* increasing the total capacity of the distribution system through larger distribution transformers, or greater shipments, or some combination of both). Again, data were not provided to support this position, but some utilities stated they were maintaining service by (a) increasing the distribution capacity of given circuits (*i.e.,* installing larger transformers); or (b) reducing the number of customers on a given circuit (*i.e.,* installing more transformers).[153] (APPA, No. 103 at p. 17; Highline Electric, No. 71 at pp. 1–2; Idaho Power, No. 139 at p. 5) For this final rule, DOE finds that neither position provides enough evidence to change its assumptions from the January 2023

[147] Net generation: the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. *See www.eia.gov/tools/glossary/index.php?id=Net%20generation#:~:text=Net%20generation%3A%20The%20amount%20of,is%20deducted%20from%20gross%20generation.*

[148] Rserve margin: The amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability. *See www.eia.gov/tools/glossary/index.php?id=R.*

[149] Capacity factor: The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period. See *www.eia.gov/tools/glossary/index.php?id=C.*

[150] Capacity factors vary by generating unit, ranging from 92 percent for nuclear generation (almost always on and available) to 24 percent for solar PV (the sun isn't always shining where the collector are located). See *www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a,* and *www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.*

[151] *See www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2023&region=1-0&cases=ref2023&start=2021&end=2050&f=A&linechart=~~~~ref2023-d020623a.103-2-AEO2023.1-0&map=ref2023-d020623a.3-2-AEO2023.1-0&ctype=linechart&sourcekey=0.*

[152] See: *https://www.regulations.gov/document/EERE-2019-BT-STD-0018-0162.*

[153] Discussed in section IV.G.2 of this document in detail.

NOPR and August 2021 Preliminary Analysis TSD. For this final rule, DOE updated its load growth assumption for liquid-immersed distribution transformers based on the change in average growth of *AEO2023:* Purchased Electricity: Delivered Electricity, which shows a year-on-year growth rate of 0.7 percent. While this value may seem low, when compounded over the analysis period it results in a significant growth of 22 percent, which is higher than the rates indicated by Idaho Power and WEC, albeit over a presumed longer timeframe.

Additionally, DOE has examined a scenario in the NIA to measure the potential impacts of increased capacity by shifting smaller units to larger units. There is little information from which to model this shift—specifically over how long a period this shift to larger capacities would occur. Based on report studying the impact of EVs on transformer overloading,[154] and the impacts of reduced transformer lifetimes from increased transformer loads [155] DOE estimated the extensive growth of the distribution system that would be needed. These studies indicate that it is distribution transformer up to 100 kVA that are at risk of overloading (EC 1B), and associated lifetime reductions, and most likely to be replaced with larger capacity equipment. These studies indicate that the risk of overload diminishes with increased capacity, with 100 kVA being the upper limit. DOE's approach shifts the capacities transformer shipments over to larger capacity equipment. DOE includes this scenario for illustrative purposes. This shift and results can be found in appendix 10C of the TSD. These results indicate that for EC 1B in the event of such a capacity shift, the national full-fuel cycle energy savings will increase by 21 percent, with the net present value of consumer savings also increasing by 19 and 20 percent, at 3 and 7 percent discount rates, respectively.

[154] Dalah, S., Aswani, D., Geraghty, M., Dunckley, J., *Impact of Increasing Replacement Transformer Size on the Probability of Transformer Overloads with Increasing EV Adoption,* 36th International Electric Vehicle Symposium and Exhibition, June, 2023. Available online at: *https://evs36.com/wp-content/uploads/finalpapers/FinalPaper_Dahal_Sachindra.pdf.*

[155] Jodie Lupton, Right-Sizing Residential Transformers for EVs, T&D World,January 2024, Available online: *https://prismic-io.s3.amazonaws.com/wwwpowerengcom/9dd90ffc-4df8-442c-92c2-eb175f687ea0_Right-sizing+residential+transformers+for+EVs.pdf.*

Table IV.8 Average First Year Losses and Energy Savings for Liquid-immersed Equipment Classes

Equipment Class	EL	TSL	Load Losses (kWh)	No-load Losses (kWh)	Energy Use (kWh)	Energy Savings (kWh)
1B - Small Single-phase Liquid-immersed (<= 100 kVA)	0	0	160	712	871	0
	1	1	150	706	856	15
	2	2	150	690	840	32
		3	150	690	840	32
	4	4	181	269	450	421
	5	5	110	342	452	420
1A - Large Single-phase Liquid-immersed (> 100 kVA)	0	0	744	2,520	3,264	0
	1	1	727	2,456	3,183	81
	2	2	688	2,474	3,161	103
	4	3	856	918	1,774	1,491
		4	856	918	1,774	1,491
	5	5	522	1,219	1,741	1,523
2A - Small Three-phase Liquid-immersed (< 500 kVA)	0	0	602	2,450	3,052	0
	1	1	597	2,407	3,004	48
	2	2	594	2,310	2,904	148
	4	3	630	1,055	1,686	1,366
		4	630	1,055	1,686	1,366
	5	5	491	1,176	1,667	1,385
2B - Large Three-phase Liquid-immersed (>= 500 kVA)	0	0	4,818	15,456	20,274	0
	1	1	4,627	15,156	19,783	491
	2	2	4,609	14,023	18,632	1,641
		3	4,609	14,023	18,632	1,641
	4	4	5,777	6,157	11,934	8,340
	5	5	3,624	7,929	11,553	8,720
12 - Submersible and Vault Liquid-immersed (all kVA)	0	0	6,441	15,511	21,951	0
		1	6,441	15,511	21,951	0
		2	6,441	15,511	21,951	0
		3	6,441	15,511	21,951	0
		4	6,441	15,511	21,951	0
	5	5	5,989	6,510	12,499	9,452

Table IV.9 Average First Year Losses and Energy Savings by Low-voltage Dry-Type Rep Units

Equipment Class	SL	TSL	Load Losses (kWh)	No-load Losses (kWh)	Energy Use (kWh)	Energy Savings (kWh)
3 – Single-phase Low-voltage Dry-type	0	0	416	953	1,369	0
	1	1	416	845	1,261	109
	2	2	394	752	1,146	224
	4	3	387	566	953	416
	5	4	413	240	654	716
	3	5	345	213	558	811
4 – Three-phase Low-voltage Dry-type	0	0	748	1,537	2,285	0
	1	1	734	1,359	2,092	193
	2	2	706	1,300	2,006	279
	3	3	771	712	1,483	802
	4	4	738	442	1,180	1,105
	5	5	651	457	1,108	1,177

Table IV.10 Average First Year Losses (kWh) and Energy Savings by Medium-voltage Dry-Type Rep Units

Equipment Class	SL	TSL	Load Losses (kWh)	No-load Losses (kWh)	Energy Use (kWh)	Energy Savings (kWh)
6 – Three-phase Medium-voltage Dry-type, Low BIL	0	0	6,108	7,280	13,387	0
	1	1	6,089	6,387	12,476	911
	2	2	5,759	6,183	11,943	1,445
	4	3	5,414	4,993	10,407	2,980
	5	4	4,682	4,253	8,934	4,453
	3	5	4,459	3,054	7,513	5,874
8 – Three-phase Medium-voltage Dry-type, Medium BIL	0	0	14,021	26,889	40,910	0
	1	1	14,406	23,927	38,333	2,577
	2	2	12,183	25,148	37,330	3,580
	3	3	18,762	10,927	29,689	11,221
	4	4	15,490	11,103	26,593	14,317
	5	5	11,492	12,348	23,839	17,071
10 – Three-phase Medium-voltage Dry-type, High BIL	0	0	13,158	29,216	42,374	0
	1	1	15,043	24,280	39,323	3,051
	2	2	12,174	26,227	38,401	3,973
	3	3	21,266	10,373	31,639	10,735
	4	4	17,662	10,264	27,926	14,448
	5	5	14,279	11,212	25,492	16,882

Chapter 7 of the final rule TSD provides details on DOE's energy use analysis for distribution transformers.

F. Life-Cycle Cost and Payback Period Analysis

DOE conducted LCC and PBP analyses to evaluate the economic impacts on individual consumers (in this case distribution utilities for liquid-immersed, and COMMERCIAL AND INDUSTRIAL entities for low-, and medium-voltage dry-type) of potential energy conservation standards for distribution transformers. The effect of amended energy conservation standards on individual consumers usually involves a reduction in operating cost and an increase in purchase cost. DOE used the following two metrics to measure consumer impacts:

▪ The LCC is the total consumer expense of an appliance or product over the life of that product, consisting of total installed cost (manufacturer selling price, distribution chain markups, sales tax, 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 product.

▪ The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more-efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost at higher efficiency levels by the change in annual operating cost for the year that amended or new standards are assumed to take effect.

For any given efficiency level, DOE measures the change in LCC relative to the LCC in the no-new-standards case, which reflects the estimated efficiency distribution of distribution transformers in the absence of new or amended energy conservation standards. In contrast, the PBP for a given efficiency level is measured relative to the baseline product.

For each considered efficiency level in each product class, DOE calculated the LCC and PBP for a nationally representative set of electric distribution utilities and commercial and industrial customers. As stated previously, DOE developed these customer samples from various sources, including utility data from the Federal Energy Regulatory Commission (FERC), EIA; and commercial and industrial data from the Commercial Building Energy Consumption Survey (CBECS) and Manufacturing Energy Consumption Survey (MECS). For each sample, DOE determined the energy consumption in terms of no-load and load losses for distribution transformers and the appropriate electricity price. By developing a representative sample of consumer entities, the analysis captured the variability in energy consumption and energy prices associated with the use of distribution transformers.

Inputs to the LCC calculation include the installed cost to the consumer, operating expenses, the lifetime of the product, and a discount rate. Inputs to the calculation of total installed cost include the cost of the equipment—which includes MSPs, retailer and distributor markups, and sales taxes—and installation costs. Inputs to the calculation of operating expenses include annual energy consumption, electricity prices and price projections, repair and maintenance costs, equipment lifetimes, and discount rates. Inputs to the PBP calculation include the installed cost to the consumer and first year operating expenses. DOE created distributions of values for equipment lifetime, discount rates, and sales taxes, with probabilities attached to each value, to account for their uncertainty and variability.

The computer model DOE uses to calculate the LCC and PBP relies on a Monte Carlo simulation to incorporate uncertainty and variability into the analysis. The Monte Carlo simulations randomly sample input values from the probability distributions and distribution transformer samples. For this rulemaking, the Monte Carlo approach is implemented as a computer simulation. The model calculated the LCC and PBP for products at each efficiency level for 10,000 individual distribution transformer installations per simulation run. The analytical results include a distribution of 10,000 data points showing the range of LCC savings for a given efficiency level relative to the no-new-standards case efficiency distribution. In performing an iteration of the Monte Carlo simulation for a given consumer, product efficiency is as a function of the consumer choice model described in section IV.F.2 of this document. If the chosen equipment's efficiency is greater than or equal to the efficiency of the standard level under consideration, the LCC and PBP calculation reveals that a consumer is not impacted by the standard level. By accounting for consumers who are already projected to purchase more-efficient products in a given case, DOE avoids overstating the potential benefits from increasing product efficiency.

DOE calculated the LCC and PBP for all consumers of distribution transformers as if each were to purchase new equipment in the expected year of required compliance with amended standards. Amended standards would apply to distribution transformers manufactured five years after the date on which any new or amended standard is published in the **Federal Register**. Therefore, DOE used 2029 as the first year of compliance with any amended standards for distribution transformers.

Table IV.11 summarizes the approach and data DOE used to derive inputs to the LCC and PBP calculations. The subsections that follow provide further discussion. Details of the model, and of all the inputs to the LCC and PBP analyses, are contained in chapter 8 of the TSD and its appendices.

Table IV.11 Summary of Inputs and Methods for the LCC and PBP Analysis*

Inputs	Source/Method
Equipment Costs	Derived by multiplying MPCs by manufacturer and distribution chain markups and sales taxes, as appropriate. Used historical data to derive a price scaling index to project product costs.
Installation Costs	Assumed not to change as a function of equipment efficiency. Installation costs are determined as a function of equipment weight or other physical characteristics.
Annual Energy Use	The total annual energy use multiplied by the hours per year. Average number of hours based on field data. Variability: Based on distribution transformer load data or customer load data.
Electricity Prices	Hourly Prices: Based on EIA's Form 861 data for 2015, scaled to 2023 using *AEO2023*. Variability: Regional variability is captured through individual price signals for each EMM region. Monthly Prices: Based on an analysis of EEI average bills, and electricity tariffs from 2019, scaled to 2023 using *AEO2023*. Variability: Regional variability is captured through individual price signals for each Census region.
Energy Price Trends	Based on *AEO2023* price projections.
Repair and Maintenance Costs	Assumed no change with efficiency level.
Product Lifetime	Average: 32 years, with a maximum of 60 years.
Discount Rates	For residential end users, approach involves identifying all possible debt or asset classes that might be used to purchase the considered equipment or might be affected indirectly. Primary data source was the Federal Reserve Board's Survey of Consumer Finances. For commercial end users, DOE calculates commercial discount rates as the weighted average cost of capital using various financial data
Compliance Date	2029

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

1. Equipment Cost

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

DOE examined historical producer price index (PPI) data for electric power and specialty transformer manufacturing available between 1967 and 2022 from the BLS.[156] Even though this PPI series may also contain prices of electrical equipment other that distribution transformers, this is the most disaggregated price series that is representative of distribution transformers. DOE assumes that this PPI is a close proxy to historical price trends for distribution transformers, including liquid-immersed, and medium-, and low-voltage dry-type transformers. The PPI data reflect nominal prices adjusted for product quality changes. The inflation-adjusted (deflated) price index for electric power and specialty transformer manufacturing was calculated by dividing the PPI series by the Gross Domestic Product Chained Price Index.

DOE has observed a spike in the trend of annual real prices between 2021 and 2022. However, when the PPI is examined at a month-by-month level, the deflated PPI from 2022 through 2023 appears to be leveling off. Specifically, the deflated monthly PPI data in Table IV.12 shows a near constant value since June 2022. DOE further examined the trends on key inputs into distribution transformers: steel, aluminum, and copper—these inputs show a similar trend over this same period.[157] [158] [159] DOE notes that the engineering analysis estimated MSPs in 2023; additionally, and that it has captured the impact of this spike, if it were realized, as a constant increase in real prices in the low economic price scenario results shown in section V.C of this document.

[156] Product series ID: PCU3353113353111. Available at *www.bls.gov/ppi/*.

[157] Steel: WPU101

[158] Aluminum: ID: WPU10250105

[159] Copper: WPU10260314

Table IV.12 Excerpt from PPI Industry Data for Power and Distribution Transformers, Deflated—April 2022 to September 2023

Year	Label	Industry Data for Power and Distribution Transformers	Iron and steel	Aluminum sheet and strip	Copper wire and cable
2022	Apr-22	0.95	1.20	1.31	1.08
2022	May-22	0.96	1.26	1.26	1.06
2022	Jun-22	0.99	1.22	1.17	1.03
2022	Jul-22	1.01	1.17	1.11	0.98
2022	Aug-22	1.02	1.11	1.05	0.93
2022	Sep-22	1.02	1.05	1.04	0.93
2022	Oct-22	0.99	1.00	1.00	0.93
2022	Nov-22	1.00	0.97	0.99	0.95
2022	Dec-22	1.00	0.96	1.01	0.97
2022	Jan-23	1.05	1.01	1.06	1.06
2022	Feb-23	1.05	1.03	1.06	1.09
2022	Mar-23	1.06	1.06	1.07	1.07
2023	Apr-23	1.06	1.08	1.04	1.06
2023	May-23	1.06	1.10	1.05	1.01
2023	Jun-23	1.06	1.08	1.03	1.02
2023	Jul-23	1.05	1.03	1.00	1.01
2023	Aug-23	1.06	1.02	1.01	1.01
2023	Sep-23	1.06	1.00	1.00	1.00

DOE received no comments on its future price trend methodology in the NOPR. For this final rule, DOE maintained the same approach for determining future equipment prices as in the NOPR and assumed that equipment prices would be constant over time in terms of real dollars (*i.e.,* constant 2023 prices).

2. Efficiency Levels

As in the January 2023 NOPR, for this final rule, DOE analyzed various efficiency levels expressed as a function of loss reduction over the equipment baseline [160] as well as an overall efficiency rating. For units greater than 2,500 kVA, there is not a current baseline efficiency level that must be met. Therefore, DOE established EL 1 for these units as if they were aligning with the current energy conservation standards efficiency vs kVA relationship, scaled to the larger kVA sizes. To calculate this, DOE scaled the maximum losses of the minimally compliant design from the next highest kVA representative unit to the 3,750 kVA size using the equipment class specific scaling relationships in TSD appendix 5C. For example, for three-phase liquid-immersed distribution transformers, the highest kVA representative unit is RU5, corresponding to a 1,500 kVA transformer. A minimally compliant 1,500 kVA design is 99.48-percent efficient and has 3,920 W of total losses at 50-percent load, with representative no-load and load losses of 1,618 W and 2,290 W respectively based on RU5. Using the updated scaling factors of 0.73 and 1.04 for no-load and load losses respectively, as described in appendix 5C, the total losses of a 3,750 kVA unit would be 9,096 W, corresponding to 99.52-percent efficient at 50-percent load.

EL 2 through EL 5 align with the same percentage reduction in loss as their respective equipment class, but rather than being relative to a baseline level, efficiency levels were established relative to EL 1 levels.

The rate of reduction is shown in Table IV.13, and the corresponding efficiency ratings in Table IV.14.

[160] Calculated as the current percentage loss (*i.e.,* 100 percent minus the current standard) multiplied by the percent reduction in loss plus the current standard

Table IV.13 Efficiency Levels as Percentage Reduction of Baseline Losses

Equipment Category	Efficiency Level				
	1	2	3	4	5 (Max-tech)
Liquid-immersed					
≤ 2500 kVA	2.5	5	10	20	40
> 2500 kVA	40*	5**	10**	20**	40**
Low-voltage Dry-type					
1ϕ	10	20	30	40	50
3ϕ	5	10	20	30	40
Medium-voltage Dry-type					
< 46 kV BIL	5	10	20	30	40
≥ 46 and < 96 kV BIL, and ≤ 2500 kVA	5	10	20	30	40
≥ 46 and < 96 kV BIL, and > 2500 kVA	43*	10**	20**	30**	40**
≥ 96 kV BIL and ≤ 2500 kVA	5	10	20	30	35
≥ 96 kV BIL and > 2500 kVA	34*	10**	20**	30**	35**

*Equipment currently not subject to standards. Therefore, reduction in losses relative to least efficient product on market.

**Reduction in losses relative to EL 1

Table IV.14 Efficiency Levels

Rep. Unit	kVA	Efficiency Level					
		0	1	2	3	4	5
1	50	99.11	99.13	99.15	99.20	99.29	99.46
2	25	98.95	98.98	99.00	99.05	99.16	99.37
3	500	99.49	99.50	99.52	99.54	99.59	99.69
4	150	99.16	99.18	99.20	99.24	99.33	99.49
5	1500	99.48	99.49	99.51	99.53	99.58	99.69
6	25	98.00	98.20	98.39	98.60	98.79	98.99
7	75	98.60	98.67	98.74	98.88	99.02	99.16
8	300	99.02	99.07	99.12	99.22	99.31	99.41
9	300	98.93	98.98	99.04	99.14	99.25	99.36
10	1500	99.37	99.40	99.43	99.50	99.56	99.62
11	300	98.81	98.87	98.93	99.05	99.16	99.28
12	1500	99.30	99.33	99.37	99.44	99.51	99.58
13	300	98.69	98.75	98.82	98.95	99.08	99.14
14	2000	99.28	99.32	99.35	99.42	99.49	99.53
15	112.5	99.11	99.13	99.15	99.20	99.29	99.46
16	1000	99.43	99.44	99.46	99.49	99.54	99.66
17	3750	N/A	99.52	99.54	99.57	99.62	99.71
18	3750	N/A	99.38	99.44	99.50	99.57	99.63
19	3750	N/A	99.33	99.40	99.46	99.53	99.56

DOE did not receive any comments regarding either the loss rates or the efficiency levels applied in the NOPR and continued their use for this final rule.

3. Modeling Distribution Transformer Purchase Decision

In the January 2023 NOPR TSD, DOE presented its modelling assumptions on how distribution transformers were purchased. DOE used an approach that focuses on the selection criteria that customers are known to use when purchasing distribution transformers. Those criteria include first costs as well as the total ownership cost (TOC) method, which combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have historically used the TOC method to determine which distribution transformers to purchase. However, comments received from stakeholders responding to the 2012 ECS NOPR (77 FR 7323) and the June 2019 Early Assessment RFI (84 FR 28254) indicated that the widespread practice of concluding the final purchase of a distribution transformer based on TOC is rare. Instead, customers have been purchasing the lowest first cost transformer design regardless of its loss performance. Respondents noted that some purchasers of distribution transformers do so on the basis of first cost in order to, among other things, maximize their inventories of transformers per dollar invested. This behavior allows transformer purchasers to have the maximum inventory of units available to quickly respond to demand for new transformers, as well as have replacements readily available in the event of transformer failure. DOE continues to explore consumer choice and market reaction to the new efficiency standards levels and the impact it would have on purchasers' inventory of transformers. This may be further explored in a future RFI. As discussed in section IV.F.3.b of this document the practice of purchasing based on first cost is unlikely to change over time.

The utility industry developed TOC evaluation as a tool to reflect the unique financial environment faced by each distribution transformer purchaser. To express variation in such factors as the cost of electric energy, and capacity and financing costs, the utility industry developed a range of evaluation factors: A and B values, to use in their calculations.[161] A and B are the

[161] In modeling the purchase decision for distribution transformers DOE developed a probabilistic model of A and B values based on

Continued

equivalent first costs of the no-load and load losses (in $/watt), respectively.

In response to the NOPR analysis, DOE received the following comments regarding the modeling of distribution transformer purchases.

a. Equipment Selection

DOE did not receive comments regarding how engineering designs were selected by the consumer choice model in the LCC and maintained the material constraints in be no-new-standards case from the January 2023 NOPR in this final rule. For the January 2023 NOPR, DOE's research indicated that distribution transformers can be fabricated with amorphous core steels that are cost competitive with conventional steels, as shown in the engineering analysis (*see* section IV.C), but they cannot currently be fabricated in the quantities needed to meet the large order requirements of electric utilities, and, as such, are limited to niche products. DOE experience shows that this lack of market response to the availability of new materials, amorphous, to be unique to the purchase of distribution transformers. The current market environment for distribution transformers is shaped primarily by the availability of products with short lead times to consumers given current demand dynamics. This in turn is driven by the availability of existing production capacity. Currently, distribution transformer capacity is primarily set up to produce equipment with GOES cores (97 percent of units). Because GOES production equipment cannot be readily modified to manufacture amorphous distribution transformers, DOE understands that this production capacity will continue to produce GOES distribution transformers unless it is entirely replaced with amorphous specific production equipment. As a result, the availability of GOES core transformers will be maintained, even as amorphous production capacity is added under amended standards.

This circumstance is unique to transformers where the production lines for GOES and amorphous core equipment are not interchangeable, meaning that to meet amended standards requiring amorphous core steel manufacturers cannot retool existing production lines, but must add new production capacity. DOE expects that, in the long term, manufacturers may begin to replace GOES production equipment with amorphous production equipment where amorphous is more cost competitive in the presence of amended standards. However, as discussed in section IV.A.5 of this document, the distribution transformer market is currently experiencing significant supply constraints, creating extended lead times and supply shortages for distribution transformers. Therefore, to address these supply shortages, manufacturers may choose to maintain their GOES production to maximize their production output in the presence of amended standards, even if amorphous production is a more cost competitive production route. To reflect this, DOE has revised its customer choice model in the no-new-standards and standards cases in this final rule to limit the variety of core steel materials by TSL to the ratios shown in Table IV.15. DOE updated the consumer choice model from the January 2023 NOPR, which did not constrain the selection of designs based on core material variety in the standards case, based on feedback received expressing that manufacturers may maintain GOES production, even in instances when amorphous transformers may be the lowest cost option (S*ee* sections IV.A.4.c and IV.A.5 of this document). These material limits account for impacts in the amended standards case where GOES steel may continue to be used to meet the trial standard levels (*see* section V.A of this document). These material limits represent a conservative view of the future where AM does not displace any GOES production, or the demand for GOES distribution transformers is not diminished in favor of AM core distribution transformers. While it is likely that over time there would be some displacement, it is too speculative for DOE to establish amended standards on such a modeling assumption. For informational purposes DOE has included LCC sensitivities where the amorphous core distribution transformers increase in availability to 10 percent, and 25 percent. These sensitivity analyses, which demonstrate a higher percentage of distribution transformer manufacturers utilizing amorphous steel cores to meet TSL 3 standards, result in increasing LCC savings for EC 1B by 62 and 193 percent, respectively. Further for EC 2B the LCC savings increased by 578 and 589 percent for increases in AM availability of 10 and 25 percent, respectively. The impacts of these sensitivities can be reviewed in appendix 8E of the final rule TSD.

utility requests for quotations when purchasing distribution transformers. In the context of the LCC the A and B model estimates the likely values that a utility might use when making a purchase decision.

Table IV.15 Applied Core Material Limits

Liquid-immersed Core Material Limitations (%)							
Core Material	**Material Class**	**No-new Std.**	**Trial Standard Level**				
			1	**2**	**3**	**4**	**5**
M3, 23HiB090	GOES	87					
M3, 23HiB090, 23PRD85	GOES		87	87			
23PDR085, M2	GOES	10					
M2*	GOES		10	10			
Amorphous	AM	3	3	3			
Any	*Any*				100	100	100
Dry-type Core Material Limitations (%)							
Core Material	**Material Class**	**No-new Std.**	**Trial Standard Level**				
			1	**2**	**3**	**4**	**5**
M4, M3, HiB-M4**	GOES	97					
PDR	GOES	3					
Amorphous	AM	0					
Any	*Any*		100	100	100	100	100

* DOE retained a constraint on M2 through EL 2 as stakeholders have noted thinner steel is more difficult and they would likely retain 0.23 mm or thicker steel volume. M2 generally is not selected in large volume anyway given the higher production costs associated with rolling thinner steel.
** Modelled as M3

b. Total Owning Cost and Evaluators

In the January 2023 NOPR Analysis TSD, DOE used TOC evaluation rates as follows: 10 percent of liquid-immersed transformer purchases were concluded using TOC, and 0 percent of low-voltage dry-type and medium-voltage dry-type transformer purchases were concluded using TOC. DOE received comments from several stakeholders regarding the rates at which TOC are practiced.

NEMA and Prolec GE commented that the current percentage of transformers that are being purchased using TOC is estimated to be below 10 percent for both single-phase and three-phase transformers. (Prolec GE, No. 120 at p. 12; NEMA, No. 141 at p. 15) However, Howard commented that in 2022, its TOC adoption rate was in the 40-percent range for both single- and three-phase liquid-immersed distribution transformers. (Howard, No. 116 at p. 19) NRECA commented that many electric cooperatives are RUS borrowers and thus use RUS Bulletin 1724D–107, ''Guide for Economic Evaluation of Distribution Transformers,'' to calculate the cost of owning a transformer over its useful life using the TOC method.[162] NRECA added that given today's supply chain challenges, its members' primary concern is the availability of transformers, not the cost, and therefore DOE's estimation of the utilities using TOC is not representative of real-world experience. (NRECA, No. 98 at p. 7)

Prolec GE, NEMA, NRECA, and Colorado Springs Utilities commented that the low usage of TOC was the implementation of DOE's current minimum efficiency levels (adopted in the April 2013 Standards Final Rule (78 FR 23335) with compliance required in 2016) due to the TOC formula becoming less relevant when defining the most cost-competitive transformer design option resulting in most customers are purchasing transformers based on lowest first-cost that meets the current DOE efficiency levels. (Prolec GE, No. 120 at p. 12; NEMA, No. 141 at p. 15; Colorado Springs Utilities, Public Meeting Transcript, No. 75 at p. 114; NRECA, No. 98 at p. 7)

WEC commented that the best interests of its customers would be served by allowing utilities to use their A and B factors to calculate efficiency requirements, as cost evaluation is unique to each utility. (WEC, No. 118 at p. 1) Rochester PU commented that it uses loss-evaluated transformers for 30-plus years and if amorphous transformers are the best choice based on its loss evaluation (which considers energy cost), then those are the transformers Rochester PU would purchase. (Rochester PU, Public Meeting Transcript, No. 75 at pp. 61–62)

Given the comments received, DOE has maintained the same modeling assumption in this final rule as it used in the January 2023 NOPR, where an estimated 10 percent of purchases are concluded using TOC. DOE notes however that this final rule is not prescriptive, and that distribution transformers can be designed to meet any combination of A and B values if the overall design meets the amended minimum efficiency standards.

Howard provided the fraction of sales that are concluded based on TOC. (Howard, No. 116 at p. 20) DOE applied the shipment weights per EMM region from Howard's data in DOE's customer choice model with an additional

[162] See: *https://www.rd.usda.gov/sites/default/files/UEP_Bulletin_1724D-107.pdf.*

percentage assigned to random EMM regions as was done in the NOPR, and the entry for California split evenly between Northern and Southern California. DOE found that for consumers who evaluate based on TOC in DOE's modeling, they are limited to the EMM regions based on the weights shown in Table IV.16.

Table IV.16 Evaluator Regional Weights

EMM Index	Description	Eval Weight
4	East Central Area Reliability Coordination Agreement	0.58%
1	Electric Reliability Council of Texas	2.80%
14	Mid-Atlantic Area Council	1.19%
4	Mid-America Interconnected Network	0.01%
8	New York	0.49%
7	New England	2.94%
2	Florida Reliability Coordinating Council	5.02%
15	Southeastern Electric Reliability Council	3.63%
18	Southwest Power Pool	2.96%
23	Northwest Power Pool	7.08%
24	Rocky Mountain Power Area	9.49%
21	California North	20.86%
22	California South	20.86%
*	*All others – random assignment*	*22.09%*

Band of Equivalents

In the August 2021 Preliminary Analysis TSD, DOE proposed the following definition for Band of Equivalents (BOE): as a method to establish equivalency between a set of transformer designs within a range of similar TOC. BOE is defined as those transformer designs within a range of similar TOCs. The range of TOC varies from utility to utility and is expressed in percentage terms. In practice, the purchaser would consider the TOC of the transformer designs within the BOE and would select the lowest first-cost design from this set.

NEMA commented that BOE is generally not used for low- or medium-voltage dry-type transformer purchases. (NEMA, No. 141 at p. 15) Based on this comment from NEMA, DOE maintained its approach from the NOPR where TOC and BOE are not applied to low- and medium-voltage distribution transformers.

Mulkey Engineering commented on the risks associated with following TOC ''to the penny,'' suggesting that a combination of TOC and BOE be used when evaluating transformer purchases. In addition to other experience-driven suggestions, Mulkey Engineering asserted a BOE rate within TOC of 10 percent. (Mulkey Engineering, No. 96 at pp. 1–2) NEMA commented that most utilities who use TOC methods also apply a band of equivalency ranging from 3–10 percent of the TOC, where the lowest first cost transformer in the band is purchased. (NEMA, No. 141 at p. 15) Finally, Prolec GE commented that BOE is used in less than half of the cases where a TOC formula is specified. (Prolec GE, No. 120 at p. 12)

Based on the comments received, DOE will maintain the definition as per the NOPR. Additionally, for this final rule, DOE included a BOE rate of 5 percent for those consumers who use TOC in the consumer choice model.

c. Non-Evaluators and First Cost Purchases

DOE defined those consumers who do not purchase based on TOC as those who purchase based on lowest first costs. DOE did not receive any comments regarding lowest first cost purchases and maintained the approach from the NOPR in this final rule.

4. Installation Cost

Installation cost includes labor, overhead, and any miscellaneous materials and parts needed to install the product. DOE used data from RSMeans to estimate the baseline installation cost for distribution transformers.[163] In the January 2023 NOPR TSD, DOE asserted that there would be no difference in installation costs between baseline and more efficient equipment. DOE also asserted that 5 percent of replacement installations would face increased costs over baseline equipment due to the need for site modifications. Stakeholders responded to DOE's assertions regarding installation costs as they related to the increases in efficiency proposed in the NOPR.

a. Overall Size Increase

Stakeholders had concerns over the increased size and weight of equipment due to amended efficiency standards, specifically that increased transformer size and weight would result in increased technical issues and increased costs when replacement transformers are installed in sensitive locations. (Cliffs, No. 105 at pp. 11–12; NEMA, No. 141 at p. 6; Highline Electric, No. 71 at pp. 1–2; Indiana Electric Co-Ops, No. 81 at p. 1; Southwest Electric, No. 87 at p. 3; Howard, No. 116 at pp. 24–25; Chamber of Commerce, No. 88 at p. 4; Pugh Consulting, No. 117 at p. 5; NRECA, No. 98 at p. 6; Entergy, No. 114 at p. 4; SBA, No. 100 at p. 6; WEC, No. 118 at p. 2; Portland General Electric, No. 130 at p. 4; Southwest Electric, No. 87 at pp. 2–3; Xcel Energy, No. 127 at p. 1; Idaho Power, No. 139 at pp. 5–6; APPA, No. 103 at p. 9; Schneider, No.

[163] Gordian, RSMeans Online, *www.rsmeans.com/products/online* (last accessed Sept. 2023).

101 at p. 2; Powersmiths, No. 112 at pp. 4–5)

The Efficiency Advocates commented that any size-related impacts resulting from DOE's proposal are not expected to significantly impact transformer installations. The Efficiency Advocates commented that as of 2015, more than 4 million AM transformers had been sold globally, with about 600,000 installed in the United States, over 1 million in China, and 1.3 million in India—this number of installed global AM units has increased several-fold since 2015. The Efficiency Advocates estimated that over 90 percent of liquid-immersed transformers sold in Canada use AM. The Efficiency Advocates commented it understands that ''well-designed AM transformers'' are not meaningfully larger than current GOES transformers and noted that DOE's NOPR analysis considered the potential impact of increased transformer size on pole and vault installations. (Efficiency Advocates, No. 121 at pp. 6–7)

In response to these comments, the amended standard in this final rule shows the following increases in transformer size and weight shown in Table IV.17 through Table IV.19. The impact on liquid immersed transformer weight om amended standards is expected to be less than 10 percent for small (≤100 kVA) single-phase (overhead and surface mounts). For large (>100 kVA) single-phase the weight is expected to increase from 16 to 21 percent. For small three-phase (<500 kVA) the expected increase in weight and footprint (ft^2) are 4 and 1 percent, respectively. For large (≥500 kVA) three-phase the expected increase in weight and footprint (ft^2) are expected to be 2 and 1 percent, respectively; with the exception of three-phase liquid-immersed distribution transformers greater than 2500 kVA where ethe increases in the weight and footprint (ft^2) are expected to be 25 and 8 percent, respectively.

Table IV.17 Estimated Transformer Weight Change for Single-phase Overhead Transformers by Rated Capacity (*lbs.*)

Capacity (kVA)	Weight (lbs.)		Delta
	No-new Standard	Amended Standard	
10	243	247	2%
15	329	334	2%
25	482	490	2%
38	660	671	2%
50	811	825	2%
75	1,099	1,118	2%
100	1,364	1,387	2%
167	2,004	2,421	21%
250	1,875	2,168	16%
333	2,324	2,687	16%
500	3,153	3,645	16%
833	4,623	5,346	16%

Note: the weights for specific capacities are scaled from the representative units 2 and 3 (see TSD chapter 5) using the scaling factors determined in TSD appendix 5C.

Table IV.18 Estimated Transformer Weight Change for Single-phase Surface Mounted Transformers by Rated Capacity (*lbs.*)

Capacity (kVA)	Weight (lbs.)			Footprint (ft^2)		
	No-new Standard	Amended Standard	Delta	No-new Standard	Amended Standard	Delta
10	280	299	7%	3.7	3.8	1.3%
15	379	406	7%	4.6	4.6	1.3%
25	556	595	7%	5.9	6.0	1.3%
38	762	814	7%	7.3	7.4	1.3%
50	936	1,000	7%	8.4	8.5	1.3%
75	1,268	1,356	7%	10.3	10.4	1.3%
100	1,573	1,682	7%	11.8	12.0	1.3%
167	2,312	2,726	18%	15.5	17.5	12.5%
250	3,128	3,689	18%	19.0	21.4	12.5%
333	3,879	4,574	18%	21.9	24.6	12.5%
500	5,261	6,205	18%	26.8	30.2	12.5%
833	7,715	9,099	18%	34.6	39.0	12.5%

Note: the weights for specific capacities are scaled from the representative unit 1 (see TSD chapter 5) using the scaling factors determined in TSD appendix 5C.

Table IV.19 Estimated Transformer Weight Change for Three-phase Surface Mounted Transformers by Rated Capacity (*lbs.*)

Capacity (kVA)	Weight (lbs.)			Footprint (ft^2)		
	No-new Standard	Amended Standard	Delta	No-new Standard	Amended Standard	Delta
30	811	842	4%	7.8	7.8	1.0%
45	1,100	1,141	4%	9.5	9.6	1.0%
75	1,613	1,674	4%	12.3	12.4	1.0%
113	2,194	2,276	4%	15.0	15.2	1.0%
150	2,713	2,815	4%	17.3	17.5	1.0%
225	3,677	3,815	4%	21.2	21.4	1.0%
300	4,563	4,734	4%	24.5	24.7	1.0%
500	1,190	1,248	5%	31.5	31.6	0.4%
667	5,862	6,003	2%	25.9	26.2	1.0%
750	6,401	6,555	2%	27.5	27.7	1.0%
833	6,925	7,092	2%	29.0	29.2	1.0%
1,000	7,942	8,133	2%	31.7	32.0	1.0%
1,500	10,765	11,024	2%	38.9	39.2	1.0%
2,000	13,357	13,679	2%	44.9	45.3	1.0%
2500	15,791	16,171	2%	50.2	50.7	1.0%
3750	17,473	21,768	25%	58.4	63.0	7.9%
5000	21,680	27,010	25%	67.4	72.7	7.9%

Note: the weights for specific capacities are scaled from the representative units 4 and 5 (see TSD chapter 5) using the scaling factors determined in TSD appendix 5C.

DOE appreciates these general comments and refers to its responses below on specific installation cost concerns.

b. Liquid-immersed

NEMA, commented that the proposed amended standard would result in medium-voltage liquid- and dry-type unit weight increasing by 50 percent and generally result in 15-percent taller, wider, and deeper units compared to those designed to meet the current standards; and that tank diameters and/or tank heights increases of 15 percent or more will create new logistical challenges. (NEMA, No. 141 at p. 6). WEB and LBA also expressed concerns regarding the potential increased weights of transformers more generally. (WEG, No. 92 at p. 2; LBA, No. 108 at p. 3)

EEI and NEMA commented that the transportation, delivery, and handling of the new (heavier) equipment will also be impacted. EEI and NEMA commented that the increased size means fewer units per truck, with larger and heavier equipment requiring more trucks to move units to their installation locations. EEI and NEMA commented that for pole mounted transformers, new poles to support the weight will have to be sourced; for pad-mounted transformers, thicker and larger concrete pads will have to be poured. EEI and NEMA added that larger and heavier also means bigger boom cranes necessary to lift such equipment will need to be procured. (EEI, No. 135 at pp. 20–21; NEMA, No. 141 at p. 3)

Idaho Falls Power and Fall River commented that amorphous core transformers are larger in size and heavier per kW rating than their counterparts, sometimes by more than 40 percent, leading to issues related to space and weight, such as placement in existing vaults where clearances must be maintained for safety reasons, or placement on poles designed to hold a specific weight. (Idaho Falls Power, No. 77 at p. 1; Fall River, No. 83 at p. 2)

WEG commented that another major consideration, especially for urban areas, will be physical space requirements, as distribution transformers in major cities are often located in some variety of physical structure with specific limitations as to what size transformer can be installed. WEG commented that increased overall transformer size could drive a significant civil engineering issue in urban areas to accommodate transformers that meet these amended standards. (WEG, No. 92 at p. 2)

As shown in in Table IV.17 through Table IV.19, DOE expects the maximum weight increase from amended standards to be no greater 25 percent for three-phase liquid-immersed transformer over 2500 kVA, representing less than 0.5 percent of unit shipped. This is much less than 50 percent increase indicated by NEMA. DOE notes that for the vast majority of unit shipped (small single-phase up to and including 100 kVA), representing 91 percent of single-phase shipments, the impact on weight is an increase of between 1 and 2 percent.

c. Overhead (Pole) Mounted Transformers

Highline Electric provided information describing its fleet of distribution transformers and limitations, including approximately 250 banks of three 75 kVA pole-mount transformers and 500 banks of three 50 kVA pole-mount transformers. Highline Electric commented that it currently does not deploy larger than 75 kVA pole-mount transformers due to pole load limitations and the proposed amended standards would result in new, standards compliant, 50 kVA transformers with a weight like existing baseline 75 kVA transformers, and compliant 75 kVA transformers with a weight more than a baseline100 kVA pole-mount unit. Highline Electric added that it discontinued use of 100 kVA pole-mount units decades ago after outage records indicated such installations were prone to unacceptable rates of pole failure. (Highline Electric, No. 71 at pp. 1–2)

Further, Highline Electric commented that if transformer weights are increased by 20–40 percent, compliant 75 kVA transformers could not be installed on Highline Electric's standard class of poles. Highline Electric commented it would instead have to: (1) Utilize pole-mount transformers that predate the proposed amended standards, which would require a two-man crew with a material handler truck plus a few hours of labor and can be done proactively or reactively during outage conditions; (2) Convert to pad-mount transformers, which would require a 3-plus man crew, a digger derrick truck, and enough hours of labor that such an operation could only be completed proactively as it would require unacceptably long outage restoration times; or, (3) Replace the existing pole to a much heavier-class of pole, which would require a 3-plus man crew, a digger derrick truck, and enough hours of labor that such an operation could only be completed proactively as it would require unacceptably long outage restoration times—this option assumes that the heavier-class of pole is available at the time of need. (Highline Electric, No. 71 at p. 2)

Idaho Power commented that it considers the 25-percent estimate for pole replacements to be too low, as it is likely that every transformer larger than 100 kVA on its distribution system would require an upsized pole. Idaho Power commented this may also be the case for 50 kVA and 75 kVA transformers. Idaho Power recommended that DOE consider increasing the 25-percent replacement number used in 2013 to better reflect the impact of the additional weight from amorphous core transformers on pole replacements. (Idaho Power, No. 139 at pp. 5–6) Additionally, Idaho Power stated it had designs for a few pole-mounted transformers with amorphous cores, noting that for 50 kVA and smaller transformers, the additional weight is not enough to increase the installation cost, but for transformers 100 kVA and larger, the weights increased between 40 and 60 percent and will likely require higher class poles resulting in increased installation costs. (Idaho Power, No. 139 at p. 5)

Alliant Energy commented that DOE's proposal presents implementation and installation challenges given the greater size and weight of amorphous core distribution transformers, which may require additional pole replacement, larger trucks for transport, and the use of cranes for installation. (Alliant Energy, No. 128 at p. 3)

Howard and Chamber of Commerce commented that the proposed amended standards may require the upgrading and/or full replacement of the brackets as IEEE standards stipulate that the top support lug must be at least five times the transformer weight. Howard and Chamber of Commerce commented that for most manufacturers, the current transformer weight limit for support lug A is about 1000 lbs., B is about 3000 lbs., and Big B is 4000 lbs. Further, Howard and Chamber of Commerce commented that the new designs under this NOPR would also increase tank diameters, moving the center of gravity further away from the pole interface and increasing the moment force on the pole bracket. (Howard, No. 116 at pp. 24–25; Chamber of Commerce, No. 88 at p. 1) Highline Electric commented that pole replacements are not directly attributable to the larger kVA capacity, but rather are attributable to the weight of these larger kVA units. Highline Electric commented that poles are not rated to hold certain amounts of kVA capacity in the air; they are rated to hold certain pounds in weight and certain pounds in wind-loading (cross-sectional area of a transformer bank). (Highline Electric, No. 71 at p. 1)

Southwest Electric commented that the proposed amended standard for single-phase designs, which typically include simpler cooling capability (fins versus cooling plates), will result in percent increases in tank and conductor weights exceeding that of 3-phase, raising the significant problem that most single-phase transformers are mounted overhead via utility poles, scaffolding, or some other platform. Southwest Electric commented that the increased weight of NOPR-compliant transformers could lead to further potential outages, pushing these annual costs even higher. (Southwest Electric, No. 87 at p. 3)

EEI, Entergy, and Pugh Consulting commented that the electric utility industry is experiencing constraints with wood pole supplies, especially poles with higher strength capacities, and an increase in demand for stronger poles could cause additional challenges. (Entergy, No. 114 at p. 4; Pugh Consulting, No. 117 at p. 5; EEI, No. 135 at pp. 21–24)

DOE's analysis at the amended standard levels indicate the following weight increases for overhead mounted distribution transformers. DOE's engineering and LCC analysis of overheard transformers are conducted for the representative units discussed in section IV.C.1, representative unit 2 (25 kVA) and representative unit 3 (500 kVA). DOE has scaled the weights determined in the engineering, and selected in the LCC model to the other common capacities shown in Table IV.17. These show that the increased weight under amended standards is projected to be modest, under 10 percent for transformers up to and including 100 kVA in capacity—which is approximately 95 percent of all single-phase shipments (in terms units) and 99 percent of overhead shipments (in terms of units). Further, the projected weights, except for 833 kVA, which are less than 0.05 percent of annual overhead units shipped, are not expected to change the application of the support lugs mentioned by NEMA from current practices.[164] The modest weight increases are below the supplied thresholds for premature pole change outs supplied by Highline Electric and Idaho Power and consequently are not expected results in undue burden of requiring new, higher-grade poles.

DOE cannot directly comment on the availability of wooden poles at higher strength classes. The comments from EEI, Entergy, and Pugh Consulting did not state which classes of poles they considered commonly used, or which classes of poles are considered higher strength. DOE reiterates that the increase in transformer weight determined in its analysis is expected to be sufficiently modest (estimated to be less than 20 percent), that it will not likely disrupt the current wooden pole supply chains, and not in the 40 to 60-percent range suggested by stakeholders. There is insufficient information to justify increased installation costs given the modest projected increase in equipment weight resulting from amended standards, however, DOE recognizes the uncertainty surrounding installation costs because it is a complex issue. DOE's technical analysis in appendix 8F of this final rule TSD shows there to be minimal load bearing impact on the structures used to mount overhead distribution transformers resulting from amended standards. However, each utility's distribution system is unique with different equipment build-outs of different vintages. Given the heterogeneous nature of distribution systems it is not possible for DOE to account for every potential hypothetical installation circumstance. To account for the uncertainty faced by distribution utilities raised in the comments above, DOE has increased the fraction of installations that will face additional costs from 5 percent in the January 2023 NOPR to 50 percent when the weight increase over current baseline equipment is greater than 10 percent.

[164] Overhead transformers at 833 kVA represent less than 0.01 precent of units shipped. *See* section G for detailed shipments projections.

NRECA commented that DOE analysis assumes like-for-like pole replacements, which is misguided. NRECA commented it expects that more transformer replacements will be necessary to allow for greater-capacity transformers due to electrification, thus requiring larger poles. (NRECA, No. 98 at p. 6)

In response to NRECA, for the purpose of estimating the cost and benefits to consumers from a modeling perspective DOE needs to bound the issue of what is considered a replacement versus new installation. While NRECA comments that it expects future replacements to be of greater capacity than what is currently installed, NRECA did not provide any information on what it considers the current typical capacity, and what they'd be replaced with in the future. DOE can agree with NRECA that, in practice, replacing a 25 kVA overhead with a new 50 kVA to maintain current levels of service can reasonably be considered a replacement. However, DOE maintains that, for example, installing a 167 kVA in the place of a 25 kVA to meet new service would be a new installation, as it would require additional planning, secondary conductors, and likely a new structure (pole).

Replacement Costs

Idaho Power typically charges between $3,500–5,000 for a pole replacement. (Idaho Power, No. 139 at p. 6) SBA provided cost estimates for wooden poles range anywhere from $500 to $1,400 per pole depending on labor and material shipping costs for small utilities. (SBA, No. 100 at p. 6) WEC commented that it does not install transformers over 4,500 lbs. on a single pole. To change to a two-pole structure will cost from $10,000 to $15,000 per transformer, assuming there is room for a two-pole structure which is not viable in all locations. WEC further commented it would cost anywhere from $2,000 to $10,000 to change out the pole for a single transformer depending on its location and what other equipment is installed on the pole, which could lead to increased costs beyond these estimates. (WEC, No. 118 at p. 2)

Based on the comments from Idaho Power, SBA and WEC DOE examined the values it used in the NOPR for the cost of pole replacement. DOE derived its values based on the RSMeans 2023, and found that the average price of a new single-pole installation ranged in cost, equipment and labor, (excluding profit, and excavation) ranged from $504 to $3,125 for 30 and 70 foot treated poles, respectively. The data from RSMeans indicates a strong relationship between pole length and cost, and did not include the additional cost for excavation that would be incurred by a utility. While the stakeholders did not provide the pole length or grades associated with the supplied costs, which DOE would expect such costs to vary on a utility-by-utility bases. Based on the information provided by stakeholders and RSMeans DOE has updated its pole replacement cost distribution for this final rule, which is a triangular distribution, for single-pole structures: low: $2,025; mode: $4,012; high: $5,999. And for multi-pole structures: low: $5,877; mode: $11,388; high: $16,899.

d. Surface (Pad) Mounted Transformers

WEC and Xcel Energy commented that pad-mounded 167 kVA single-phase transformers will roughly increase in size (1–4 inches) under the proposed amended standards, and that this increase of the dimensional footprint will be incompatible with pad and fiberglass box-pad foundations that the current transformers are using and have used for many decades. WEC and Xcel Energy stated that this will make it more difficult to use existing underground infrastructure (trench and connections) for transformer changeouts and may result in extra digging to install a compatible fiberglass box and pad. (Xcel Energy, No. 127 at p. 1; WEC, No. 118 at pp. 2–3)

Southwest Electric commented that the proposed amended standard for 3-phase designs will result in a significant weight increase, exceeding the weights the pads were designed to support—especially in areas where seismic zoning requires additional anchoring. (Southwest Electric, No. 87 at pp. 2–3)

Howard commented that it and other manufacturers have difficulty meeting some utilities' pad dimensions at the current efficiency levels. Howard commented it had taken exception to required footprint dimensions in the past for 100 kVA and above dual voltage and 167 kVA and above straight voltage transformers for many utilities. Regarding three-phase pads, Howard commented that utilities may have two or three different pad sizes, and a bigger footprint for transformers will require utilities to utilize large pad sizes. (Howard, No. 116 at p. 21)

In response to these comments, DOE's analysis shows an increase in weight and footprint area of 7 and 3 percent, respectively, for single-phase surface-mounted liquid-immersed distribution transformers up to and including 100 kVA, and an increase in weight and footprint area of 18 and 19 percent, respectively, for single-phase liquid-immersed surface mounted distribution transformers greater than100 kVA designed to meet the current standard, see Table IV.17. Additionally, DOE's analysis shows that that the impacts to weight and footprint area of three-phase surface mounted distribution transformers to be 4 and 1 percent, respectively, for capacities up to 500 kVA, while for capacities equal to or greater than 500 kVA the increase in weight and footprint area is 2 and 1 percent (5 and 1 percent for 500 kVA) over current standards, see Table IV.19. Commenters did not provide enough information to directly model the costs of increasing pad, or fiberglass box size; however, for some of the capacity ranges the increase in weight, particularly for single-phase surface-mounted distribution transformers over 100 kVA, may be enough to trigger the need to use additional materials or different crews to complete installations. While the specifics are not available to DOE, to capture these additional costs DOE increased the fraction of installation from 5 percent in the NOPR (88 FR 1777) to 50 percent in this final rule.

e. Logistics and Hoisting

Chamber of Commerce, EEI, Portland General Electric, WEC, and Southwest Electric commented that heavier transformers may trigger transportation and hoisting considerations and challenges, likely requiring flatbed trucks, additional permitting, and cranes to install. These commenters stated that weight and access restrictions for roads and certain areas, especially in rural places, may create further challenges for replacements of transformers. (Portland General Electric, No. 130 at p. 4; Southwest Electric, No. 87 at pp. 2–3; Chamber of Commerce, No. 88 at pp. 4–5; EEI, No. 135 at pp. 24–28; WEC, No. 118 at pp. 2–3) SPA commented that small utilities were concerned whether their current equipment (namely trucks and lifts) will be able to handle increased sizes and weights. (SBA, No. 100 at p. 6) Chamber of Commerce commented that larger transformers will consume more storage space on an individual basis than current GOES models, thereby reducing the number of units that can be held in reserve to support system restoration efforts. (Chamber of Commerce, No. 88 at pp. 4–5)

As discussed in sections IV.F.4.c and IV.F.4.d of this document, DOE's analysis shows that the projected increase in size and weight of transformers under amended standards to be modest, which DOE believes will not be disruptive to current logistics and hoisting procedures.

f. Installation of Ancillary Equipment: Gas Monitors and Fuses

APPA insinuated that DOE did not account for the costs associated with more than 10 million gas monitors, which would equate to $25 billion in additional costs, and that these additional costs alone would exceed the $13 billion of economic benefits cited in the NOPR. APPA further stated that DOE's analysis did not consider the additional cost of labor to remove and install the gas monitor and the cost of a replacement transformer. (APPA, No. 103 at p. 11)

DOE disagrees with the assertions from APPA that there would be an additional cost of $25 billion to consumers of distribution transformers for the removal and installation of gas monitor or other ancillary equipment not related to the transformer's efficiency. A gas monitor is a device installed by the customer that monitors the conditions of the transformer's internal insulating fluid to help predict future equipment faults. Due to the additional cost, they are typically installed by utilities on larger capacity (kVA) transformers for operational reliability, with their installation occurring regardless of the efficiency of the transformer. Further, DOE has never prescribed the use of gas monitors for distribution transformers; gas monitors are installed at the discretion of each individual utility, and outside the scope of DOE's authority. DOE has not included the use of gas monitoring equipment in this final rule.

APPA commented that amorphous core transformers experience higher inrush currents, creating the need for external protective devices (*e.g.,* fuses) to be reviewed and changed. APPA commented that the amount of core steel significantly increases, creating a much heavier device that could force the utility to rerate framing hardware while increasing pole size and class and potentially increasing costs in a way that DOE has not addressed. (APPA, No. 103 at p. 15)

DOE's installation costs analysis includes increasing installation costs as a function of transformer weight. As generally indicated by stakeholders through their comments, there are many factors and costs that are unique to each utility's operating procedures; as such, these factors are beyond the practicality of DOE to model in detail. As discussed in section IV.F.4.c of this document, DOE increased the fraction of installations which would incur additional cost under amended standards from 5 to 50 percent to account for the circumstances described by APPA. This fraction is constant at all considered efficiency levels above the baseline.

g. Low-Voltage Dry-Type

Increased floor space to store the LVDT units—product is commercially available off the shelf (COTS) device (Schneider, No. 101 at p. 15) Powersmiths commented that an amended standard for LVDT, which requires amorphous cores would, for retrofits, to be successful the replacement transformers. In addition to customization to meet footprint needs, they will require design changes to match terminal layout, impedance. temperature rise and k-rating. These accommodations, while possible today with GOES core transformers, will further increase the level of difficulty of retrofitting with amorphous-based transformers. Many older transformers are closer to people than newer buildings so any increase the audible noise is a big issue—noise is one of the biggest complaints from users, itself driving retrofit projects.'' (Powersmiths, No. 112 at p. 4–5)

To alleviate concerns from Schneider and Powersmiths regarding potential installation issues arising from moving to amended standard that are achievable only using amorphous core materials, the amended standards in this final rule are set at level that is achievable with GOES core materials, TSL 3.

5. Annual Energy Consumption

For each sampled customer, DOE determined the energy consumption for a distribution transformer at different efficiency levels using the approach described previously in section IV.E of this document.

6. Energy Prices

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

Fall River commented that the amended standards would in turn drive up costs, which would ultimately be borne by rate payers where energy burdens are already growing at a severe rate. (Fall River, No. 83 at p. 2) DOE notes that any amended standard is determined based on the specific criteria discussed in section III.F.1 of this document, and in the context of Fall River's comment criteria III.F.1.b of this document. The results in section V.B.1.a of this document show that most consumers are projected to show a net benefit from amended standards.

DOE did not receive any further comments regarding its electricity costs analysis and maintained the approach used in the NOPR for this final rule.

7. Maintenance and Repair Costs

Repair costs are associated with repairing or replacing product components that have failed in an appliance; maintenance costs are associated with maintaining the operation of the product. Typically, small incremental increases in product efficiency produce no, or only minor, changes in repair and maintenance costs compared to baseline efficiency products. In the NOPR analysis, DOE asserted that maintenance and repair costs do not increase with transformer efficiency.

Cliffs commented that the costs of the rule would not outweigh the benefits if the substantial increase in price and maintenance requirements for amorphous metal cores were properly accounted for. (Cliffs, No. 105 at p. 16) However, Cliffs did not specify how amorphous metal cores increase the maintenance costs of a transformer nor did it provide any data to showcase these higher costs. DOE understands that most distribution transformers incur few maintenance or repairs throughout their product lifetime and typically none to the transformer core. As discussed in sections IV.A.4.a and IV.G.3 of this document, both amorphous and GOES cores can be rewound and rebuilt. DOE does not have any data to support that amorphous core transformers would be subject to substantially higher maintenance costs than GOES core transformers.

DOE did not receive any comments on this assertion and continued its assumptions that maintenance and repair costs do not increase with transformer efficiency for this final rule analysis.

8. Transformer Service Lifetime

For distribution transformers, DOE used a distribution of lifetimes, with an estimated average of 32 years and a maximum of 60 years.[165] 78 FR 23336, 23377. DOE received the following comments on transformer service lifetime. Prolec GE and NEMA commented that the current estimated transformer lifetime of 32 years is adequate, as distribution transformers are extremely durable. However, Prolec GE and NEMA noted, certain factors might accelerate transformer replacement rates, such as increased trends in transformer loading practices due to electrification and decarbonization initiatives. (Prolec GE, No. 120 at p. 13; NEMA, No. 141 at p. 16) APPA commented that GOES service transformers are typically run to failure (no operations and maintenance costs) and last 40 to 70 years and that amorphous distribution transformers are likely to have a lifetime of 20 to 40 years. (APPA, No. 103 at p. 11)

In response to Prolec GE, NEMA, and APPA, DOE characterizes transformer lifetimes as distribution of the possibility of equipment failure in each year up to the estimated maximum lifetime—in this case 60 years—to account for circumstances where the transformer either fails prematurely (degradation from heat or otherwise) or is prematurely removed from service. APPA's range of service lifetimes for GOES and amorphous distribution transformers overlaps considerably with DOE's estimates. Additionally, DOE finds the APPA discussion from Australia regarding high amorphous failure rates to be excessively speculative, based on anecdotal discussion with unknown persons regarding an unknown sample size of distribution transformers of unknown vintage in a jurisdiction that operates on a fundamentally different frequency (50 hertz *versus* 60 hertz), and presented without citation, data, or analysis. For this final rule DOE is maintaining the distribution of service lifetimes from the NOPR; the distribution is shown in Table IV.20.

[165] Barnes, P. R., Van Dyke, J. W., McConnell, B. W. & Das, S. *Determination Analysis of Energy Conservation Standards for Distribution Transformers.* (Oak Ridge National Laboratory, 1996).

Table IV.20 Distribution of Transformer Failure Rates

Age	Cumulative Chance of Failure	Age	Cumulative Chance of Failure	Age	Cumulative Chance of Failure
1	0.5%	21	18.8%	41	78.0%
2	1.0%	22	20.9%	42	80.8%
3	1.5%	23	23.1%	43	83.4%
4	2.0%	24	25.4%	44	85.7%
5	2.5%	25	27.9%	45	87.9%
6	3.0%	26	30.5%	46	89.9%
7	3.5%	27	33.2%	47	91.6%
8	4.1%	28	36.1%	48	93.1%
9	4.6%	29	39.1%	49	94.4%
10	5.2%	30	42.2%	50	95.6%
11	5.8%	31	45.4%	51	96.5%
12	6.5%	32	48.7%	52	97.3%
13	7.2%	33	52.0%	53	97.9%
14	8.0%	34	55.4%	54	98.5%
15	8.9%	35	58.8%	55	98.9%
16	10.3%	36	62.2%	56	99.2%
17	11.8%	37	65.6%	57	99.4%
18	13.4%	38	68.9%	58	99.6%
19	15.1%	39	72.0%	59	99.7%
20	16.9%	40	75.1%	60	100.0%

9. 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 (*e.g.,* LCC). The first step is to assume that the actual 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 this final rule, DOE estimated a statistical distribution of commercial customer discount rates that varied by distribution transformer category, by calculating the cost of capital for the different varieties of distribution transformer owners.

DOE's method views the purchase of a higher-efficiency appliance as an investment that yields a stream of energy cost savings. DOE derived the discount rates for the LCC analysis by estimating the cost of capital for companies or public entities that purchase distribution transformers. For private firms, the weighted average cost of capital (WACC) is commonly used to estimate the present value of cash flows to be derived from a typical company project or investment. Most companies use both debt and equity capital to fund investments, so their cost of capital is the weighted average of the cost to the firm of equity and debt financing, as estimated from financial data for publicly traded firms in the sectors that purchase distribution transformers.[166] As discount rates can differ across industries, DOE estimates separate discount rate distributions for a number of aggregate sectors with which elements of the LCC building sample can be associated.

DOE did not receive any comments in the NOPR to its approach to determining discount rates and maintained the same approach in this final rule. The discount rates applied to consumers of liquid-immersed distribution transformers are shown in Table IV.21, and those applied to low- and medium-voltage dry-type distribution transformers are shown in Table IV.22.

[166] Previously, Damodaran Online provided firm-level data, but now only industry-level data is available, as compiled from individual firm data, for the period of 1998–2018. The data sets note the number of firms included in the industry average for each year.

Table IV.21 Applied Discount Rates by Sector for Liquid-Immersed Distribution Transformers

Bin	Bin Range (%)	Investor-Owned Utility Sector			Publicly Owned Utilities (State/Local Government)		
		Bin Average Discount Rate (%)	Weight (% of companies)	# of Companies	Bin Average Discount Rate (%)	Weight	# of Companies
1	< 0				-2.4	5.8	8
2	0–1				0.9	2.2	3
3	1–2	1.6	0.6	13	1.6	22.6	31
4	2–3	2.76	1.5	33	2.5	24.8	34
5	3–4	3.69	50.2	1101	3.5	34.3	47
6	4–5	4.33	36.2	793	4.2	10.2	14
7	5–6	5.43	4.1	91			
8	6–7	6.54	4.5	99			
9	7–8	7.37	2.9	63			
10	8–9						
11	9–10						
12	10–11						
13	11–12						
14	12–13						
15	≥ 13						
Weighted Average		4.20			2.51		

Table IV.22 Applied Discount Rates by Sector for Liquid-Immersed Distribution Transformers

Bin	Bin Range (%)	Investor-Owned Utility Sector			Publicly Owned Utilities (State/Local Government)		
		Bin Average Discount Rate (%)	Weight (% of companies)	# of Companies	Bin Average Discount Rate (%)	Weight	# of Companies
1	< 0				-2.4	5.8	8
2	0–1				0.9	2.2	3
3	1–2	1.6	0.6	13	1.6	22.6	31
4	2–3	2.76	1.5	33	2.5	24.8	34
5	3–4	3.69	50.2	1101	3.5	34.3	47
6	4–5	4.33	36.2	793	4.2	10.2	14
7	5–6	5.43	4.1	91			
8	6–7	6.54	4.5	99			
9	7–8	7.37	2.9	63			
10	8–9						
11	9–10						
12	10–11						
13	11–12						
14	12–13						
15	≥ 13						
Weighted Average		4.20			2.51		

See chapter 8 of the NOPR TSD for further details on the development of consumer discount rates.

10. Energy Efficiency Distribution in the No-New-Standards Case

To accurately estimate the share of consumers that would be affected by a potential energy conservation standard at a particular efficiency level, DOE's LCC analysis considered the projected distribution (market shares) of product efficiencies under the no-new-standards case (*i.e.,* the case without amended or new energy conservation standards) in the compliance year. This approach reflects the fact that some consumers may purchase products with efficiencies greater than the baseline levels in the absence of new or amended standards. To determine an appropriate basecase against which to compare various potential standard levels, DOE used the purchase-decision model described in section IV.F.3 of this document, where distribution transformers are purchased based on either lowest first cost or lowest TOC (with BOE). In the no-new-standards case, distribution transformers are chosen from among the entire range of available distribution transformer designs for each representative unit simulated in the engineering analysis based on this purchase-decision model with the core material constraints discussed in section IV.F.3.a of this document. This selection is constrained only by purchase price in most cases (90 percent, and 100 percent for liquid-immersed and all dry-type transformers, respectively) and reflects the MSPs of the available designs determined in the engineering analysis in section IV.C of this document.

DOE did not receive any comments regarding its methodology of determining its energy efficiency distribution in the no-new-standards case and maintained the methodology from the NOPR in this final rule.

11. Payback Period Analysis

The PBP is the amount of time (expressed in years) it takes the consumer to recover the additional installed cost of more-efficient products, compared to baseline products, through energy cost savings. PBPs 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 for each efficiency level are the change in total installed cost of the product and the change in the first-year annual operating expenditures relative to the baseline. DOE refers to this as a ''simple PBP'' because it does not consider changes over time in operating cost savings. The PBP calculation uses the same inputs as the LCC analysis when deriving first-year operating costs.

As noted previously, EPCA 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 first year's energy savings resulting from the standard, as calculated under the applicable test procedure. (42 U.S.C. 6295(o)(2)(B)(iii)) For each considered efficiency level, DOE determined the value of the first year's energy savings by calculating the energy savings in accordance with the applicable DOE test procedure, and multiplying those savings by the average energy price projection for the year in which compliance with the amended standards would be required.

Carte commented that a study found that the increase to 2016 transformer efficiencies will take approximately 80 years to payback (no citation provided) and questions what the PBP would be for the proposed standard level. (Carte, No. 140 at pp. 6–7) In response to Carte, DOE acknowledges that some consumers may be negatively affected by amended standards due to the details of how they operate their equipment. For example, consumers with low electricity costs may take longer to realize the benefits from more efficient equipment than might be seen from consumers with higher electricity costs. DOE's LCC analysis uses a Monte Carlo simulation to incorporate uncertainty and variability into the analysis precisely to capture and quantify the differences in costs and benefits to consumers Nationally. Carte's comment did not provide details for DOE to alter its LCC and PBP analysis. The PBPs of this final rule is shown in section V.C.1 through V.C.3 of this document.

G. Shipments Analysis

DOE uses projections of annual product shipments to calculate the national impacts of potential amended or new energy conservation standards on energy use, NPV, and future manufacturer cash flows.[167] The shipments model takes an accounting approach, tracking market shares of each product class and the vintage of units in the stock. Stock accounting uses product shipments as inputs to estimate the age distribution of in-service product stocks for all years. The age distribution of in-service product stocks is a key input to calculations of both the NES and NPV, because operating costs for any year depend on the age distribution of the stock.

As in the NOPR, for this final rule DOE projected distribution transformer shipments for the no-new standards case by assuming that long-term growth in distribution transformer shipments will be driven by long-term growth in electricity consumption. For this final rule, DOE did not receive any comments regarding initial shipments estimates presented in the NOPR—which were based on data from the previous final rule, data submitted to DOE from interested parties and confidential manufacturer interviews. These initial shipments are shown for the assumed compliance year (2029), by distribution transformer category, in Table IV.23 through Table IV.25. DOE developed the shipments projection for liquid-immersed distribution transformers by assuming that annual shipments growth is equal to growth in electricity consumption (sales) for all sectors, as given by the *AEO2023* forecast through 2050. DOE's model assumed that growth in annual shipments of dry-type distribution transformers would be equal to the growth in electricity consumption for COMMERCIAL AND INDUSTRIAL sectors, respectively. The model starts with an estimate of the overall growth in distribution transformer capacity, and then estimates shipments for particular representative units and capacities, using estimates of the recent market shares for different design and size categories.

Idaho Power commented that it supported DOE's approach and believed it was still valid. (Idaho Power, No. 139 at p. 6)

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

Table IV.23 Estimated Liquid-Immersed Shipments for 2029 (units) by Typical Capacities

	Equipment Class				
	EC01A	EC01B	EC02A	EC02B	EC12
Phases	1		3		
Cap. Range	> 100 kVA	<= 100 kVA	< 500 kVA	>= 500 kVA	NSV
10		36,958			
15		104,845			
25		364,972			
30			24		
38		70,814			
45			584		
50		338,936			
75		115,659	4,376		
100		116,068			
113			1,547		
150			14,191		
167	46,162				
225			4,150		
250	768				
300			22,964		
333	691				
500	517			24,937	8
667	43			42	7
750				3,690	30
833	622			26	26
1,000				4,101	96
1,500				6,030	154
2,000				2,985	131
2500				5,562	539
3750				293	
5000				121	
Total	48,803	1,148,251	47,836	47,786	990

Table IV.24 Estimated Low-Voltage Dry-Type Shipments for 2029 (units) by Typical Capacities

EC	EC03	EC04
Phases	1	3
10	3	
15	2,679	17,652
25	5,963	
30		42,878
38	3,624	
45		45,196
50	5,585	
75	3,366	59,684
100	2,111	
113		26,729
150		21,167
167		
225		7,511
250	27	
300		3,942
333		
500		2,425
667		
750		589
833		
1000		16
1500		11
2000		
2500		
3750		
5000		
Total	23,357	227,800

Table IV.25 Estimated Medium-Voltage Dry-Type Shipments for 2029 (units) by Typical Capacities

EC	EC05	EC06	EC07	EC08	EC09	EC10
BIL	20–45 kV		46–95 kV		≥ 96 kV	
Phases	1	3	1	3	1	3
10	255		184		61	
15	255	5	184		61	
25	61		41		20	
30		10				
38	61		41		20	
45		10				
50	31		20		10	
75	31	4	20	2	10	
100	12		20		6	
113		31		4		
150		36		5		
167	7		10		3	
225		30		12		
250	15		20		3	
300	15	93		31		25
333	12		20		4	
500		181		87		75
667						
750		73		123		76
833						
1000		46		247		198
1500				370		249
2000				617		286
2500				617		402
3750				12		8
5000				4		3
Total	756	518	561	2,132	199	1,323

1. Equipment Switching

In the January 2023 NOPR, DOE stated MVDTs can be used as replacements for liquid-immersed distribution transformers, but DOE has historically considered it as an edge case due to the differences in purchase price as well as consumer sensitivity to first costs. At the time it proposed amended standards, DOE did not have sufficient data to model the substitution of liquid-immersed distribution transformers with MVDTs. DOE requested comment on the topic of using MVDT as a substitute for liquid-immersed distribution transformers. 88 FR 1754, 1782. NEMA responded that this is not typical, and these two categories of distribution transformers coexist in the market. (NEMA, No. 141 at p. 16) Additionally, Prolec GE commented that switching tended to be with three-phase substation transformers for indoor applications. (Prolec GE, No. 120 at p. 13)

In response to comments from NEMA and Prolec GE, DOE did not include the possible replacement of liquid-immersed distribution transformers with MVDT or *vice versa* in its analysis of this final rule.

2. Trends in Distribution Transformer Capacity (kVA)

In response to the August 2021 Preliminary Analysis, NEMA commented that as consumer demand increases due to migration to all-electric homes and buildings, it stands to reason that kVA sizes will increase over time as infrastructure upgrades capacity to serve these consumer demands. Likewise, NEMA commented that investments in renewable energy generation would cause changes to transformer shipments, unit sizes, and selections, and that DOE should examine non-static capacity scenarios, where kVA of units by category increases over time as NEMA members express growth in average kVA of ordered units over time in recent years, presumably due to increased electrification of consumer and industrial applications. 88 FR 1722, 1782. In response to the NOPR, NEMA further commented that roughly 15 percent of the low-voltage commercial market is increasing their distribution capacity sizes, going from 500 kVA to 1,000 or 1,500 kVA. (NEMA, No. 141 at p. 16) Additionally, DOE has found evidence that a similar shift in transformer capacity occurs with liquid-immersed distribution transformer to meet increasing loads.[168] DOE's approach to shifting capacities is discussed in section E.3.a, Idaho Power commented it believes the base data used in the April 2013 Standards Final Rule was scaled from 1992 and 1995 data, and there have been many energy efficiency standards that have been incorporated over the last 30 years. Idaho Power recommended that DOE consider updating the standard to reflect current loading data and include advanced data collection methods that provide more granular data. Idaho Power added that many power companies have automated meter read data that could be leveraged for better analysis. (Idaho Power, No. 139 at p. 5)

DOE agrees with Idaho Power's comments that since the CBECS last included monthly demand and energy use profiles for respondents in 1992 and 1995 editions that many energy efficiency standards have been promulgated. For its dry-type analysis, DOE used the hourly load data for COMMERCIAL AND INDUSTRIAL customers from data provided to the IEEE TF (from 2020 and 2021) to scale

[168] Dahal, S, Aswami D, Geraghty M, Dunckley, J. *Impact of Increasing Replacement Transformer Sizing on the Probability of Transformer Overloads with Increasing EV Adoptions.* 36th International Electric Vehicle Symposium and Exhibition Sacramento. California, USA, June 2023.

these monthly values in its loading analysis for low-, and medium-voltage dry-type distribution transformers (*see* chapter 7 of this final rule TSD). DOE is aware that many utilities meter their customers using real-time meters; however, DOE does not have the authority to demand such data from said utilities. Instead, DOE must rely on such industry initiatives such as the IEEE TF or individual companies to voluntarily come forward with data.

3. Rewound and Rebuilt Equipment

APPA estimated that more than 15 percent of transformers used Nationally are rebuilt/rewound units. These units would have been rebuilt/rewound by the owning utility or as a service performed by rewinding business. (APPA, No. 103 at p 11; NEMA, No. 141 at p. 15) Howard and APPA commented that rewinding was a common occurrence (especially for units greater than 300 kVA) and that the service life could be extended up to 60 years. (APPA, No. 103 at p. 11; Howard, No. 116 at p. 21) However, NEMA responded that rebuilding, as they understood, did not typically occur with liquid-filled distribution transformers and was undertaken typically as a consequence of equipment failure unrelated to end of life. NEMA further commented that to its knowledge, no one was rebuilding low-voltage distribution transformers. (NEMA, No. 141 at p. 15)

APPA continued that because most of a transformer's parts can be reused when rewinding (or when other repairs are made), it is possible that a new core could be installed in the old transformer, that costs could be lower, and that lead times could be currently shorter than purchasing new equipment. However, APPA stated that the rewinding equipment used for GOES core transformers is incompatible with amorphous core transformers, and for amorphous transformers the rewinding process is more complex (time-consuming) and therefore more expensive, resulting in a loss of benefit from rewinding to individual utilities and cutting the total available capacity of transformers. (APPA, No. 103 at pp. 11–12) Also, Idaho Power commented that it has refurbished some transformers and returned them to service. Idaho Power stated that this decision is based on reduced lead time and availability rather than cost, which is somewhat close between new and refurbished transformers. Idaho Power stated that its refurbished units are put back into inventory and used according to their nameplate data. (Idaho Power, No. 139 at p. 7)

Despite the contradictory statements from NEMA and APPA, DOE is aware that transformer rewinding/repair is a service available to utilities, either as an ''in-house'' service or at an external repair shop that provides an additional avenue for utilities to maintain transformer stocks (as indicated by Idaho Power). DOE has viewed the rewind/repair services as additive and not in direct competition with new distribution transformer manufacturers. While APPA asserts that amorphous core rewinding may be more complex and diminishes the value of rewinding these transformers, DOE understands that rewinding this equipment is still possible and that a shift to amorphous core transformers does not negate the value of these services. Additionally, this final rule can be met with GOES core materials for approximately 90 percent of projected annual units shipments.

Regarding APPA's comment about reusing transformer parts to potential reduce lead times, DOE notes that the transformer rebuilding/rewinding market has historically been relatively small. Rebuilding a distribution transformer requires additional labor (because labor is required both to deconstruct the transformer and rebuild it) that has made purchasing a new distribution transformer the preferred option when replacing a failed transformer. While recently there has been an uptick in transformer rebuilds, that is primarily a function of long lead times for new transformers and likely temporary as the transformer market recalibrates. Further, in response to Howard, as rewound equipment falls outside the scope of DOE authority, they are not considered in this final rule.

H. National Impact Analysis

The NIA assesses the national energy savings (NES) and the NPV from a national perspective of total consumer costs and savings that would be expected to result from new or amended standards at specific efficiency levels.[169] (''Consumer'' in this context refers to consumers of the product being regulated.) DOE calculates the NES and NPV for the potential standard levels considered based on projections of annual product shipments, along with the annual energy consumption and total installed cost data from the energy use and LCC analyses. For the present analysis, DOE projected the energy savings, operating cost savings, product costs, and NPV of consumer benefits over the lifetime of distribution transformers sold from 2029 through 2058.

DOE evaluates the impacts of new or amended standards by comparing a case without such standards with standards-case projections. The no-new-standards case characterizes energy use and consumer costs for each product class in the absence of new or amended energy conservation standards. For this projection, DOE considers historical trends in efficiency and various forces that are likely to affect the mix of efficiencies over time. DOE compares the no-new-standards case with projections characterizing the market for each product class if DOE adopted new or amended standards at specific energy efficiency levels (*i.e.,* the TSLs or standards cases) for that class. For the standards cases, DOE considers how a given standard would likely affect the market shares of products with efficiencies greater than the standard.

DOE uses a spreadsheet model to calculate the energy savings and the national consumer costs and savings from each TSL. Interested parties can review DOE's analyses by changing various input quantities within the spreadsheet. The NIA spreadsheet model uses typical values (as opposed to probability distributions) as inputs.

Table IV.26 summarizes the inputs and methods DOE used for the NIA analysis for the final rule. Discussion of these inputs and methods follows the table. *See* chapter 10 of the final rule TSD for further details.

[169] The NIA accounts for impacts in the 50 states and U.S. territories.

Table IV.26 Summary of Inputs and Methods for the National Impact Analysis

Inputs	Method
Shipments	Annual shipments from shipments model.
Compliance Date of Standard	2029
Efficiency Trends	No-new-standards case: constant over time. Standard cases: constant over time
Annual Energy Consumption per Unit	Annual weighted-average values are a function of energy use at each TSL.
Total Installed Cost per Unit	Annual weighted-average values are a function of cost at each TSL. Incorporates projection of future product prices based on historical data.
Annual Energy Cost per Unit	Annual weighted-average values as a function of the annual energy consumption per unit and energy prices.
Repair and Maintenance Cost per Unit	Annual values do not change with efficiency level.
Energy Price Trends	*AEO2023* projections (to 2050) and constant thereafter.
Energy Site-to-Primary and FFC Conversion	A time-series conversion factor based on *AEO2023*.
Discount Rate	3% and 7%.
Present Year	2024

1. Equipment Efficiency Trends

A key component of the NIA is the trend in energy efficiency projected for the no-new-standards case and each of the amended standards cases. Section IV.F.3 of this document describes how DOE developed an energy efficiency distribution for the no-new-standards case for each of the considered equipment classes for the year of anticipated compliance with an amended or new standard. As discussed in section IV.F.3 of this document, DOE has found that the vast majority of distribution transformers are purchased based on first cost. For both the no-new-standards case and amended standards case, DOE used the results of the consumer choice mode in the LCC, described in section IV.F.3 of this document, to establish the shipment-weighted efficiency for the year potential standards are assumed to become effective (2029). For this final rule, despite the availability of a wide range of efficiencies, DOE modelled that these efficiencies would remain static over time because the purchase decision is largely based on first costs (*see* section IV.F.3 of this document) and DOE's application of constant future equipment costs (*see* section IV.F.1 of this document).

2. National Energy Savings

The national energy savings analysis involves a comparison of national energy consumption of the considered products between each TSL and the case with no new or amended energy conservation standards. DOE calculated the national energy consumption by multiplying the number of units (stock) of each product (by vintage or age) by the unit energy consumption (also by vintage). DOE calculated annual NES based on the difference in national energy consumption for the no-new-standards case and for each higher-efficiency standard case. DOE estimated energy consumption and savings based on site energy and converted the electricity consumption and savings to primary energy (*i.e.,* the energy consumed by power plants to generate site electricity) using annual conversion factors derived from *AEO2023*. For natural gas, primary energy is the same as site energy. Cumulative energy savings are the sum of the NES for each year over the timeframe of the analysis.

Use of higher-efficiency equipment is occasionally associated with a direct rebound effect, which refers to an increase in utilization of the equipment due to the increase in efficiency and its lower operating cost. A distribution transformer's utilization is entirely dependent on the aggregation of the connected loads on the circuit the distribution transformer serves. Greater utilization would result in greater PUL on the distribution transformer. Any increase in distribution transformer PUL is coincidental and not related to rebound effect. NEMA and Howard agreed that a rebound effect is not needed for distribution transformers analysis. (NEMA, No. 141 at p. 16; Howard, No. 116 at p. 22) Howard additionally speculated that a possible caveat to this is that utility companies could conceivably be inclined to increase the load on more efficient transformers. (Howard, No. 116 at p. 22)

For this final rule, DOE has maintained the approach used in the NOPR and has not applied an additional rebound effect in the form of additional load. DOE accounts for incidental load growth on the distribution transformer resulting from additional connections not related to the rebound effect due to increased equipment efficiency in the LCC analysis in the form of future load growth. *See* section 0 for more details on DOE approach to load growth.

In 2011, in response to the recommendations of a committee on ''Point-of-Use and Full-Fuel-Cycle Measurement Approaches to Energy Efficiency Standards'' appointed by the National Academy of Sciences, DOE announced its intention to use FFC 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 51281 (Aug. 18, 2011). After evaluating the approaches discussed in the August 18, 2011 notice, DOE published a statement of amended policy in which DOE explained its determination that EIA's National Energy Modeling System (NEMS) is the most appropriate tool for its FFC analysis and its intention to use NEMS for that purpose. 77 FR 49701 (Aug. 17, 2012). NEMS is a public domain, multi-sector, partial equilibrium model of the U.S. energy sector [170] that EIA uses to prepare its *Annual Energy Outlook.* The FFC factors incorporate losses in production and delivery in the case of natural gas (including fugitive emissions) and additional energy used to produce and deliver the various fuels used by power plants. The approach used for deriving FFC measures of energy use and emissions is described in appendix 10B of the final rule TSD.

3. Net Present Value Analysis

The inputs for determining the NPV of the total costs and benefits experienced by consumers are (1) total annual installed cost, (2) total annual operating costs (energy costs and repair and maintenance costs), and (3) a discount factor to calculate the present value of costs and savings. DOE calculates net savings each year as the difference between the no-new-standards case and each standards case in terms of total savings in operating costs versus total increases in installed costs. DOE calculates operating cost savings over the lifetime of each product shipped during the projection period.

As discussed in section IV.F.1 of this document, DOE developed distribution transformers price trends based on historical PPI data. DOE applied the same trends to project prices for each product class at each considered efficiency level, which was a constant price trend through the end of the analysis period in 2058. DOE's projection of product prices is described in appendix 10C of the NOPR TSD.

To evaluate the effect of uncertainty regarding the price trend estimates, DOE investigated the impact of different product price projections on the consumer NPV for the considered TSLs for distribution transformers. In addition to the default price trend, DOE considered two product price sensitivity cases: (1) a high price decline case based on the years between 2003 and 2019 and (2) a low price decline case based on the years between 1967 and 2002. The derivation of these price trends and the results of these sensitivity cases are described in appendix 10C of the NOPR TSD.

The operating cost savings are energy cost savings, which are calculated using the estimated energy savings in each year and the projected price of the appropriate form of energy. To estimate energy prices in future years, DOE multiplied the average regional energy prices by the projection of annual national-average electricity price changes in the Reference case from *AEO2023,* which has an end year of 2050. To estimate price trends after 2050, DOE maintained the price constant at 2050 levels. As part of the NIA, DOE also analyzed scenarios that used inputs from variants of the *AEO2023* Reference case that have lower and higher economic growth. Those cases have lower and higher energy price trends compared to the Reference case. NIA results based on these cases are presented in appendix 10C of the final rule TSD.

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. For this final rule, DOE estimated the NPV of consumer benefits using both a 3-percent and a 7-percent real discount rate. DOE uses these discount rates in accordance with guidance provided by the Office of Management and Budget (OMB) to Federal agencies on the development of regulatory analysis.[171] 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.

I. Consumer Subgroup Analysis

In analyzing the potential impact of new or amended energy conservation standards on consumers, DOE evaluates the impact on identifiable subgroups of consumers that may be disproportionately affected by a new or amended national standard. The purpose of a subgroup analysis is to determine the extent of any such disproportional impacts. DOE evaluates impacts on particular subgroups of consumers by analyzing the LCC impacts and PBP for those particular consumers from alternative standard levels. For this NOPR, DOE analyzed the impacts of the considered standard levels on two subgroups: (1) utilities serving low population densities and (2) utility purchasers of vault (underground) and subsurface installations. DOE used the LCC and PBP model to estimate the impacts of the considered efficiency levels on these subgroups. Chapter 11 in the NOPR TSD describes the consumer subgroup analysis.

1. Utilities Serving Low Customer Populations

In rural areas, mostly served by electric cooperatives (COOPs), the number of customers per distribution transformer is lower than in metropolitan areas and may result in lower PULs.

Idaho Power commented that low-population areas should include adjustments in the PUL and it supported the DOE adjustments to the PUL. Idaho Power commented that its transformers in rural areas do not experience the same levels of loading as in densely populated areas. (Idaho Power, No. 139 at p. 5) NEMA commented that for liquid-filled transformers, its members estimated PUL would typically be 10 percent of RMS-equivalent nameplate rating. (NEMA, No. 141 at p. 16) Further, PSE indicated that an increase in equipment costs of 50 percent would not be ideal for COOPs, as these additional costs would ultimately fall on their member-owners. (PSE, No. 98 at pp. 9–10)

For this final rule, as in the January 2023 NOPR (88 FR 1722, 1785) and April 2013 Standards Final Rule, DOE reduced the PUL by adjusting the distribution of *IPLs*, as discussed in section IV.E.2.a of this document, resulting in the PULs shown below in Table IV.27. Further, DOE altered the customer sample to limit the distribution of discount rates (see section IV.F.9 of this document) to those observed by State and local governments discussed in IV.F.9 of this document.

In the NOPR, DOE stated that while COOPs deploy a range of distribution transformers to serve their customers, in low population densities the most common unit is a 25 kVA pole overhead

[170] For more information on NEMS, refer to *The National Energy Modeling System: An Overview* DOE/EIA–0581(2023), May 2023 (Available at: *https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2023).pdf*) (Last accessed Oct. 23, 2023).

[171] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* Available at *www.whitehouse.gov/omb/information-for-agencies/circulars* (last accessed January 2, 2024). DOE used the prior version of Circular A–4 (September 17, 2003) in accordance with the effective date of the November 9, 2023 version.

liquid-immersed distribution transformer, which is represented in this analysis as representative unit 2B of equipment class 1B (small single-phase liquid-immersed). NRECA suggested that 15 kVA transformers are used more commonly in areas with densities of six customers per mile. (NRECA, No. 98 at p. 7)

DOE recognizes the suggestion by NRECA that the most common capacity used by their members to serve areas with very low customer densities would be 15 kVA. However, DOE's engineering analysis is limited to 25 kVA in this final rule, which is embodied in the results for equipment class 1B, single-phase distribution transformers up to and including 100 kVA.

The results of the subgroups analysis are presented in section IV.I.1 for equipment class 1B. As equipment class 1B encompasses designs that are both pole-mounted (representative unit 2B) and pad-mounted (representative unit 1B) these results represent the capacity scaled, shipment weighted average consumer benefits. NRECA stated that the 15 kVA pole mounted unit is the most used in low costumer density installations—this equipment is represented by representative unit 2B (a 25 kVA pole mount). It can be inferred through examining the LCC results by representative unit that shows that consumer benefits for pole mounted transformers are higher than those of pad mounted transformers, and that the consumer benefits for the 15 kVA pole mounted units would likely be greater than those shown for the entirety of equipment class 1B.[172]

Table IV.27 Distribution of Per-Unit-Load for Liquid-Immersed Distribution Transformers Owned by Utilities Serving Low Populations

Equipment Class	Mean RMS	Mean IPL	Mean PUL
1B	0.27	0.60	0.16

2. Utility Purchasers of Vault (Underground) and Subsurface Installations

In some urban areas, utilities provide service to customers by deploying parts of their transformer fleet in subsurface vaults, or other prefabricated underground concrete structures, referred to as vaults. At issue in the potential amended standards case is that the volume (ft^3) of the more efficient replacement transformers may be too large to fit into the existing vault, which would have to be replaced to fit the new equipment. This analysis is applied to the representative units 15 and 16, specifically defined in the engineering analysis for vault and submersible liquid-immersed distribution transformers (see section IV.C.1 of this document).

DOE received numerous comments on the topic of installing transformers in vaults: Subsurface and Confined Space Installations. APPA commented that its members do not have an inventory of existing vaults or their locations and dimensions; and that most vaults were built to ''fit'' the equipment that is housed within the vault, and currently many do not have ''safe working space'' for workers, given rules changes since they were built. APPA commented that such vaults are currently grandfathered into many of the work rules, but having to expand them to take a new transformer that is larger will mean also retrofitting them to safe working space rules. APPA added that under these circumstances, if the transformer is only 10 or 15 percent larger than the vault, expansion will likely be much larger. (APPA, No. 103 at p. 10)

APPA commented that the $23,550 cost assigned in the NOPR to replace an existing vault by DOE is low for transformers installed in building interior vaults. By way of example, APPA commented that simple single-story buildings with parking lot-located vaults may cost at least $200,000; and there may be as much as a $4,000,000 to $50,000,000 discrepancy in vault replacement cost for a multi-story building that would need to be braced and supported to have the foundation removed to expand the vault. (APPA, No. 103 at p. 9) Carte also speculated that in extreme cases, such as rooftop vaults, a weight increase could be achieved by reinforcing the structure. (Carte, No. 140 at p. 7) APPA and the Chamber of Commerce commented that DOE did not account for the potential of significant increased infrastructure replacement and business disruption costs that would be incurred if replacement transformers could not fit into existing locations. (Chamber of Commerce, No. 88 at p. 4; APPA, No. 103 at p. 9) Pugh Consulting commented that for submersible transformers, installing a new transformer that is larger than the existing vault size would lead to significant costs for utilities and municipal governments, including costs associated with potential soil testing to determine if soil can be removed and costs associated with shutting down streets, highways, and sidewalks while a vault is expanded. (Pugh Consulting, No. 117 at p. 6)

DOE recognizes the potential for the cost to install transformers underground, or in building vaults to carry tremendous financial risk to utilities. While the examples provided by APPA, Carte, Chamber of Commerce, and Pugh Consulting are extreme cases where a utility's decision to alter or upgrade the existing installation location could lead to service disruptions, and maybe even health and safety liabilities. It is reasonable that utilities exercising good governance and financial responsibility to their ratepayers would approach such extreme projects only after exhausting all other avenues of maintaining service. As such DOE views these examples as edge cases. Further, stakeholders did not provide any technical information, such as specific transformer designs, weights, volumes; whether these cost estimates are for vaults that contain single or banks of multiple transformers from which DOE can improve its technical analysis. As such DOE is limited to revising its existing model. To address the cost concerns that stakeholders raised regarding the cost being too low in the NOPR, DOE reexamined the costs presented in RSMeans and found they lacked details such as excavation, disposal or fill—further they didn't account the additional costs associated with working in space confined spaces. To better capture these costs, for this final rule DOE has revised its transformer

[172] See appendix 8E of the TSD for LCC results by representative unit.

vault installation cost function to the following:

$$Transformer\ Vault\ Installation\ Cost = 220.37 \times DTVolume^{1.1436}$$

Table IV.28 Transformer Vault Installation Costs (2022$)

Volume (ft^3)	Replacement Cost (2022$)	Cost per ft^3 (2022$)
200	94,321	472
300	149,964	500
400	208,386	521
500	268,964	538

The Efficiency Advocates commented that the creation of equipment classes for submersible distribution transformers (equipment class 12) will largely mitigate any size concerns regarding underground vaulted network transformer installations because the vast majority of these are submersible designs and thus would not have to meet the higher efficiency levels proposed for other liquid-immersed transformer equipment classes. (Efficiency Advocates, No. 75 at p. 35)

DOE separated the vault and submersible equipment into their own equipment class (equipment class 12) which are designed to operate under higher heat loads which are experienced by equipment installed in enclosed spaces than general purpose distribution transformers. DOE is not amending standards for this equipment at this time precisely for the multitude of installation challenges described by commenters.

J. Manufacturer Impact Analysis

1. Overview

DOE performed an MIA to estimate the financial impacts of amended energy conservation standards on manufacturers of distribution transformers and to estimate the potential impacts of such standards on employment and manufacturing capacity. The MIA has both quantitative and qualitative aspects and includes analyses of projected industry cash flows, the INPV, investments in research and development (R&D) and manufacturing capital, and domestic manufacturing employment. Additionally, the MIA seeks to determine how amended energy conservation standards might affect manufacturing employment, capacity, and competition, as well as how standards contribute to overall regulatory burden. Finally, the MIA serves to identify any disproportionate impacts on manufacturer subgroups, including small business manufacturers.

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 include data on the industry cost structure, unit production costs, equipment shipments, manufacturer markups, and investments in R&D and manufacturing capital required to produce compliant equipment. The key GRIM outputs are the INPV, which is the sum of industry annual cash flows over the analysis period, discounted using the industry-weighted average cost of capital, and the impact to domestic manufacturing employment. The model uses standard accounting principles to estimate the impacts of more-stringent energy conservation standards on a given industry by comparing changes in INPV and domestic manufacturing employment between a no-new-standards case and the various standards cases (*i.e.,* TSLs). To capture the uncertainty relating to manufacturer pricing strategies following amended standards, the GRIM estimates a range of possible impacts under different manufacturer markup scenarios.

The qualitative part of the MIA addresses manufacturer characteristics and market trends. Specifically, the MIA considers such factors as a potential standard's impact on manufacturing capacity, competition within the industry, the cumulative impact of other DOE and non-DOE regulations, and impacts on manufacturer subgroups. The complete MIA is outlined in chapter 12 of the final rule TSD.

DOE conducted the MIA for this rulemaking in three phases. In Phase 1 of the MIA, DOE prepared a profile of the distribution transformer manufacturing industry based on the market and technology assessment, preliminary manufacturer interviews, and publicly available information. This included a top-down analysis of distribution transformer manufacturers that DOE used to derive preliminary financial inputs for the GRIM (*e.g.,* revenues; materials, labor, overhead, and depreciation expenses; selling, general, and administrative expenses (SG&A); and R&D expenses). DOE also used public sources of information to further calibrate its initial characterization of the distribution transformer manufacturing industry, including company filings of form 10–K from the SEC,[173] corporate annual reports, the U.S. Census Bureau's ''Economic Census,'' [174] and reports from D&B Hoovers.[175]

In Phase 2 of the MIA, DOE prepared a framework industry cash flow analysis to quantify the potential impacts of amended energy conservation standards. The GRIM uses several factors to determine a series of annual cash flows starting with the announcement of the standard and extending over a 30-year period following the compliance date of the standard. These factors include annual expected revenues, costs of sales, SG&A and R&D expenses, taxes, and capital expenditures. In general, energy conservation standards can affect manufacturer cash flow in three distinct ways: (1) creating a need for increased investment, (2) raising production costs per unit, and (3) altering revenue due to higher per-unit prices and changes in sales volumes.

In addition, during Phase 2, DOE developed interview guides to distribute to manufacturers of distribution transformers in order to develop other key GRIM inputs, including product and capital conversion costs, and to gather additional information on the anticipated effects of energy conservation standards on revenues, direct employment, capital assets, industry competitiveness, and subgroup impacts.

In Phase 3 of the MIA, DOE conducted structured, detailed interviews with representative

[173] *See: www.sec.gov/edgar*

[174] *See: www.census.gov/programs-surveys/asm/data/tables.html*

[175] *See: app.avention.com*

manufacturers. During these interviews, DOE discussed engineering, manufacturing, procurement, and financial topics to validate assumptions used in the GRIM and to identify key issues or concerns. As part of Phase 3, DOE also evaluated subgroups of manufacturers that may be disproportionately impacted by amended standards or that may not be accurately represented by the average cost assumptions used to develop the industry cash flow analysis. Such manufacturer subgroups may include small business manufacturers, low-volume manufacturers (LVMs), niche players, and/or manufacturers exhibiting a cost structure that largely differs from the industry average. DOE identified one subgroup for a separate impact analysis: small business manufacturers. The small business subgroup is discussed in section VI.B, ''Review under the Regulatory Flexibility Act,'' and in chapter 12 of the final rule TSD.

2. Government Regulatory Impact Model and Key Inputs

DOE uses the GRIM to quantify the changes in cash flow due to amended standards that result in a higher or lower industry value. The GRIM uses a standard, annual discounted cash flow analysis that incorporates manufacturer costs, manufacturer markups, shipments, and industry financial information as inputs. The GRIM models changes in costs, distribution of shipments, investments, and manufacturer margins that could result from amended energy conservation standards. The GRIM spreadsheet uses the inputs to arrive at a series of annual cash flows, beginning in 2024 (the base year of the analysis) and continuing to 2058. DOE calculated INPVs by summing the stream of annual discounted cash flows during this period. For manufacturers of distribution transformers, DOE used a real discount rate of 7.4 percent for liquid-immersed distribution transformers, 11.1 percent for LVDT distribution transformers, and 9.0 percent for MVDT distribution transformers, which was derived from the April 2013 Standards Final Rule and then modified according to feedback received during manufacturer interviews.[176]

The GRIM calculates cash flows using standard accounting principles and compares changes in INPV between the no-new-standards case and each standards case. The difference in INPV between the no-new-standards case and a standards case represents the financial impact of amended energy conservation standards on manufacturers. As discussed previously, DOE developed critical GRIM inputs using a number of sources, including publicly available data, results of the engineering analysis, and information gathered from industry stakeholders during the course of manufacturer interviews. The GRIM results are presented in section V.B.2 of this document. Additional details about the GRIM, the discount rate, and other financial parameters can be found in chapter 12 of the final rule TSD.

a. Manufacturer Production Costs

Manufacturing more efficient equipment is typically more expensive than manufacturing baseline equipment due to the use of more complex components, which are typically more costly than baseline components. The changes in the MPCs of covered equipment can affect the revenues, gross margins, and cash flow of the industry.

During the engineering analysis, DOE used transformer design software to create a database of designs spanning a broad range of efficiencies for each of the representative units. This design software generated a bill of materials. DOE then applied markups to allow for scrap, handling, factory overhead, and other non-production costs, as well as profit, to estimate the MSP.

These designs and their MSPs are subsequently inputted into the LCC customer choice model. For each efficiency level and within each representative unit, the LCC model uses a consumer choice model and criteria described in section IV.F.3 of this document to select a subset of all the potential designs options (and associated MSPs). This subset is meant to represent those designs that would actually be shipped in the market under the various analyzed TSLs. DOE inputted into the GRIM the weighted average cost of the designs selected by the LCC model and scaled those MSPs to other selected capacities in each design line's KVA range.

For a complete description of the MSPs, see chapter 5 of the final rule TSD.

b. Shipments Projections

The GRIM estimates manufacturer revenues based on total unit shipment projections and the distribution of those shipments by efficiency level. Changes in sales volumes and efficiency mix over time can significantly affect manufacturer finances. For this analysis, the GRIM uses the NIA's annual shipment projections derived from the shipments analysis from 2024 (the base year) to 2058 (the end year of the analysis period). *See* chapter 9 of the final rule TSD for additional details.

c. Product and Capital Conversion Costs

Amended energy conservation standards could cause manufacturers to incur conversion costs to bring their production facilities and equipment designs into compliance. DOE evaluated the level of conversion-related expenditures that would be needed to comply with each considered efficiency level in each equipment class. For the MIA, DOE classified these conversion costs into two major groups: (1) product conversion costs; and (2) capital conversion costs. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make equipment designs comply with amended energy conservation standards. Capital conversion costs are investments in property, plants, and equipment necessary to adapt or change existing production facilities such that new compliant equipment designs can be fabricated and assembled.

For capital conversion costs, DOE prepared bottom-up estimates of the costs required to meet the analyzed amended energy conservation standards at each EL for each representative unit. Major drivers of capital conversion costs include changes in core steel variety (and thickness), core weight, and core stack height, all of which are interdependent and can vary by efficiency level. The MIA used the estimated quantity of the core steel (by steel variety) for each EL at each representative unit that was modeled as part of the engineering analysis and incorporated into the LCC analysis, to estimate the additional production equipment that the distribution transformer industry would need to purchase in order to meet each analyzed EL.

Capital conversion costs are primarily driven at each EL by the potential need for the industry to expand production capacity for the potential increase in amorphous alloy used in distribution transformer cores. In the January 2023 NOPR, DOE estimated that an

[176] See Chapter 12 of the April 2013 Standards Final Rule TSD for discussion of where initial discount factors were derived, available online at *www.regulations.gov/document/EERE-2010-BT-STD-0048-0760.* For the April 2013 Standards Final Rule, DOE initially calculated a 9.1 percent discount rate, however during manufacturer interviews conducted for that rulemaking, manufacturers suggested using different discount rates specific for each equipment class group. During manufacturer interviews conducted for the January 2023 NOPR, manufacturers continued to agree that using different discount rates for each equipment class group is appropriate.

amorphous production line capable of producing 1,200 tons annual of amorphous cores would cost approximately $1,000,000 in capital investments. This capital investment includes costs associated with purchasing annealing ovens, core cutting machines, lacing tables, as well as additional conveyors and cranes to move the potentially larger amorphous cores, new winding machines and assembly tools specific to amorphous core production. Lastly, this capital investment also accounts for the potential additional production floor space that could be needed to accommodate these additional or larger production equipment that would be required to manufacture amorphous cores. The quantity of amorphous cores are outputs of the engineering analysis and the LCC. At higher ELs, the percent of distribution transformers selected in the LCC consumer choice model that have amorphous cores increases. Additionally, at the highest ELs, the quantity of amorphous material per distribution transformer also increases. As the increasing stringency of the ELs drive the use of more amorphous cores in distribution transformers (and more amorphous material per distribution transformer), capital conversion costs increase.

For product conversion costs, DOE understands the production of amorphous cores requires unique production expertise from a manufacturer's employees and engineering labor to create new equipment designs for distribution transformers using amorphous cores. For manufacturers without experience with amorphous core production, standards that would likely be met using amorphous cores would require the development or the procurement of the technical knowledge to produce cores as well as potentially re-training production employees. Because amorphous material is thinner and more brittle after annealing, materials management, safety measures, and design considerations that are not associated with non-amorphous materials would need to be implemented.

In the January 2023 NOPR, DOE estimated product conversion costs would be equal to 100 percent of the normal annual industry R&D expenses for those ELs where a majority of the market would be expected to transition to amorphous material. These one-time product conversion costs would be in addition to the annual R&D expenses normally incurred by distribution transformer manufacturers. These one-time expenditures account for the design, engineering, prototyping, re-training of production employees, and other R&D efforts the industry would have to undertake to move to a predominately amorphous market. For ELs that would not require the use of amorphous cores, but would still require distribution transformer models to be redesigned to meet higher efficiency levels, the January 2023 NOPR estimated product conversion costs would be equal to 50 percent of the normal annual industry R&D expenses. These one-time product conversion costs would also be in addition to the annual R&D expenses normally incurred by distribution transformer manufacturers.

Several interested parties commented on the conversion cost estimate used in the January 2023 NOPR. Several interested parties commented that manufacturers converting from GOES core production to amorphous core production will require large investments and the acquisition of several production equipment as well as re-training production employees. MTC commented that using amorphous cores requires different mandrels, winding, assembly processes, and equipment, including specialty annealing equipment and that the costs are significant and would be a major cost burden on distribution transformer manufacturers. (MTC, No. 119 at p. 19) Prolec GE commented that converting to amorphous cores would require investment in larger production lines in addition to other manufacturing equipment like cutting lines and annealing ovens. (Prolec GE, No. 120, at pp. 2–3) TMMA commented that in order to meet the standards proposed in the January 2023 NOPR, distribution transformer manufacturers will be required to make a significant investment for new manufacturing equipment, including cutting machines and annealing ovens. (TMMA, No. 138 at pp. 2–3) NEMA commented that producing distribution transformers that use amorphous cores requires manufacturers to reconfigure their assembly processes, including time to retrain electricians to match transformer coils to calibrate with the properties of the new steel and the steel tanks which house both the coil and cores will need to be reconfigured to match these new dimensions. (NEMA, No. 141 at p. 3) Schneider commented that the January 2023 NOPR conversion cost estimates only considered core conversion costs when in actuality the standards proposed in the January 2023 NOPR would require new winding equipment to handle larger cores, expanded conveyors, cranes, and ovens to handle larger equipment, and potentially new facilities to handle the larger manufacturing footprints. (Schneider, No. 101 at p. 11) Howard commented that in addition to the capital equipment to produce amorphous cores, some facilities will need to be upgraded to accommodate the additional core-making equipment. (Howard, No. 116 at p. 2) Carte commented that amorphous core production is totally different than GOES core production and would require either a large expansion of their plant or purchasing cores from an external vendor. (Carte, No. 140 at p. 1) Eaton commented that distribution transformer manufacturers that currently manufacture GOES cores will be left with scrapping their equipment due to very little shared processes or equipment between GOES and amorphous steel. (Eaton, No. 137 at p. 26) Lastly, WEG commented that the standards proposed in the January 2023 NOPR would require 50 percent of their operations to be retooled for amorphous core production and their employees would have to be completely retrained. (WEG, No. 92 at p. 3)

DOE acknowledges that distribution transformer manufacturers would incur significant conversion costs to convert production facilities that are currently designed to produce GOES cores into production facilities that would produce amorphous steel cores in order to meet energy conservation standards. The January 2023 NOPR and this final rule analysis attempts to capture the full costs that distribution transformer manufacturers would incur to be able to produce compliant distribution transformers analyzed in this rulemaking. The cost estimates used in the January 2023 NOPR and this final rule analysis, include manufacturing equipment used in the cutting lines, annealing ovens, new winding equipment to handle larger cores, expanded conveyors and cranes, as well as costs to expand production floor space.

Several interested parties commented that the conversion cost estimates used in the January 2023 NOPR were underestimated and should be increased. Cliffs commented that the substantial conversion costs estimated in the January 2023 NOPR are far below the reasonably foreseeable economic impact on manufacturers. (Cliffs, No. 105 at p. 14) Additionally, Cliffs commented that the January 2023 NOPR conversion cost estimates were based on manufacturer interviews conducted in 2019 and did not account for the significant inflationary forces have substantially increased capital equipment costs by at least 50 percent. (*Id.*) Cliffs continued by commenting that in order for manufacturers to comply with the standards proposed in the January 2023 NOPR, it would require new investments of between $30 and $50 million for each individual manufacturer to retool existing production factories, which they estimate would cost the entire industry between $500 million and $800 million to convert all distribution transformer production facilities into being capable of producing amorphous cores for the entire U.S. distribution transformer market. (Cliffs, No. 105 at p. 15) Hammond stated that they estimate having their production facility produce amorphous cores for all of their distribution transformers would take twice as long to produce and would require $40 million to $45 million in investment to ensure current and planned capacity could be shifted to the production of distribution transformers using amorphous cores. (Hammond, No. 142 at p. 2) Howard commented that if standards directly or indirectly force all distribution transformer designs only to use amorphous cores, the investment required from a monetary and time perspective would be even larger and longer that the conversion costs estimated in the January 2023 NOPR. (Howard, No. 116 at p. 3) Howard commented that they estimate distribution transformer manufacturers would need to invest between $500 million and $1 billion to convert all distribution transformer manufacturing to accommodate producing amorphous cores for all distribution transformers sold in the U.S. (Howard, No. 116 at p. 2) Prolec GE commented that it would need to invest approximately $50 million to convert their liquid-immersed distribution transformer production, which currently used GOES cores to use amorphous cores. (Prolec GE, No. 120 at p. 1) WEG commented that they estimate that it would take 5–7 years to retool their distribution transformer production facilities to support the necessary production equipment and methods to produce amorphous core transformers at an estimated investment of between $25 million and $30 million. (WEG, No. 92 at pp. 3–4) Additionally WEG commented that developing amorphous core designs would require building 20 prototypes and need three full time engineers to complete this transition to all amorphous core distribution transformers. WEG estimates this engineering effort would cost their company approximately $2 million. (WEG, No, 92 at pp. 1–2)

As part of this final rule MIA, DOE reexamined the estimated conversion costs used in the January 2023 NOPR. For this final rule analysis, DOE continues to use the same methodology to estimate the conversion costs that industry would incur at each analyzed EL for each representative unit. However, DOE has increased the estimated capital conversion costs used in the January 2023 NOPR from $1,000,000 in capital investments to build a production line capable of producing distribution transformers that use 1,200 tons annually of amorphous core material to $2,000,000 in capital investments for the same quantity of amorphous core material. This increase in capital investments reflect both the inflationary market mentioned by Cliffs and the additional production equipment that would be in addition to the production equipment that is specific to amorphous core production, as well as the potential increase in production floor space that might be needed to accommodate additional or larger production equipment associated with amorphous core production.

Additionally, DOE increased the estimated product conversion costs for distribution transformers using amorphous cores from 100 percent of the annual industry R&D expenses to be 150 percent of the annual industry R&D expenses; and for distribution transformers continuing to use GOES cores from 50 percent the annual industry R&D expenses to be 75 percent of annual R&D expenses. The end result is that product conversion cost estimates used in this final rule analysis are 50 percent more than the product conversion cost estimates used in the January 2023 NOPR, for the same level of amorphous core production requirements. These one-time product conversion costs would be in addition to the annual R&D expenses normally incurred by distribution transformer manufacturers. This increase in product conversion costs from the January 2023 NOPR to this final rule analysis reflect the additional redesigning, engineering, prototyping, re-training of production employees, and other R&D efforts the industry would have to undertake to move to producing distribution transformers using amorphous cores.

The conversion costs by TSL and representative unit are displayed in Table IV.29. These conversion costs are incorporated into the cash flow analysis discussed in section V.B.2.a. The industry-wide conversion cost estimates to convert all distribution transformer manufacturing to accommodate producing amorphous cores for all distribution transformers sold in the U.S. (which would occur at TSL 5) would be approximately $825 million. This industry-wide conversion estimate aligns with the estimates that several interested parties suggested in response to the January 2023 NOPR.

Table IV.29. Final Rule Conversion Cost Estimates by TSL and Representative Unit

	Total Industry Conversion Cost per TSL for each Rep Unit (*millions 2022$*)				
	TSL 1	**TSL 2**	**TSL 3**	**TSL 4**	**TSL 5**
Rep Unit 1A	$3.4	$3.5	$19.1	$19.1	$24.7
Rep Unit 1B	$14.9	$15.5	$15.5	$85.2	$110.0
Rep Unit 2A	$3.9	$4.1	$24.3	$24.3	$28.6
Rep Unit 2B	$38.7	$40.5	$40.5	$240.5	$282.6
Rep Unit 3	$0.3	$0.3	$1.7	$1.7	$2.1
Rep Unit 4A	$11.3	$11.7	$54.6	$54.6	$58.3
Rep Unit 4B	$12.9	$13.5	$13.5	$62.6	$66.9
Rep Unit 5	$15.7	$17.0	$17.0	$95.3	$114.0
Rep Unit 6	$0.7	$0.7	$0.7	$1.0	$4.1
Rep Unit 7	$12.3	$14.1	$31.0	$69.5	$71.5
Rep Unit 8	$2.5	$2.5	$4.4	$16.2	$16.2
Rep Unit 9	$0.1	$0.1	$0.1	$0.6	$0.6
Rep Unit 9V	$0.1	$0.1	$0.1	$0.4	$0.4
Rep Unit 10	$0.1	$0.1	$0.9	$0.9	$1.0
Rep Unit 10V	$0.0	$0.0	$0.1	$0.1	$0.1
Rep Unit 11	$0.1	$0.4	$0.4	$0.4	$0.5
Rep Unit 11V	$0.1	$0.4	$0.4	$0.4	$0.5
Rep Unit 12	$2.8	$2.8	$18.5	$18.8	$19.7
Rep Unit 12V	$0.0	$0.0	$0.2	$0.2	$0.2
Rep Unit 13	$0.1	$0.1	$0.1	$0.4	$0.4
Rep Unit 13V	$0.0	$0.0	$0.0	$0.2	$0.2
Rep Unit 14	$1.6	$1.6	$11.5	$11.7	$12.0
Rep Unit 14V	$0.0	$0.0	$0.1	$0.1	$0.1
Rep Unit 15	$-	$-	$-	$-	$0.0
Rep Unit 16	$-	$-	$-	$-	$5.4
Rep Unit 17	$0.5	$0.5	$0.5	$3.9	$4.5
Rep Unit 18	$0.0	$0.0	$0.3	$0.3	$0.3
Rep Unit 19	$0.0	$0.0	$0.0	$0.2	$0.2
Total	**$122.2**	**$129.6**	**$255.5**	**$708.6**	**$825.1**

Capital and product conversion costs are key inputs into the GRIM and directly impact the change in INPV (which is outputted from the model) due to analyzed amended standards. The GRIM assumes all conversion-related investments occur between the year of publication of this final rule and the year by which manufacturers must comply with the amended standards. The conversion cost figures used in the GRIM can be found in section V.B.2.a of this document. For additional information on the estimated capital and product conversion costs, see chapter 12 of the final rule TSD.

d. Manufacturer Markup Scenarios

MSPs include direct manufacturing production costs (*i.e.,* labor, materials, and overhead estimated in DOE's MPCs) and all non-production costs (*i.e.,* SG&A, R&D, and interest), along with profit. To calculate the MSPs in the GRIM, DOE applied non-production cost markups to the MPCs estimated in the engineering analysis for each equipment class and efficiency level. Modifying these manufacturer markups in the standards case yields different sets of impacts on manufacturers. For the MIA, DOE modeled two standards-case manufacturer markup scenarios to represent 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 scenario; and (2) a preservation of operating profit scenario. These scenarios lead to different manufacturer markup values that, when applied to the MPCs, result in varying revenue and cash flow impacts.

Under the preservation of gross margin percentage markup scenario, DOE applied a single uniform ''gross margin percentage'' across all efficiency levels, which assumes that manufacturers would be able to maintain the same amount of profit as a percentage of revenues at all efficiency levels within an equipment class. This scenario assumes that manufacturers would be able to maintain the same amount of profit as a percentage of revenues at all TSLs, even as the MPCs increase in the standards case. Based on data from the April 2013 Standards Final Rule, publicly available financial information for manufacturers of distribution transformers, and comments made during manufacturer interviews, DOE estimated a gross margin percentage of 20 percent for all distribution transformers.[177] This is the same value used in the January 2023 NOPR. Because this scenario assumes that manufacturers would be able to maintain the same gross margin percentage as MPCs increase in response to the analyzed energy conservation standards, it represents the upper bound to industry profitability

[177] The gross margin percentage of 20 percent is based on a manufacturer markup of 1.25.

under amended energy conservation standards.

Under the preservation of operating profit scenario, DOE modeled a situation in which manufacturers are not able to increase per-unit operating profit in proportion to increases in MPCs. Under this scenario, as the MPCs increase, manufacturers reduce their manufacturer markups (on a percentage basis) to a level that maintains the no-new-standards operating profit (in absolute dollars). The implicit assumption behind this scenario is that the industry can only maintain its operating profit in absolute dollars after compliance with amended standards. Therefore, operating margin in percentage terms is reduced between the no-new-standards case and the analyzed standards cases. DOE adjusted the manufacturer markups in the GRIM at each TSL to yield approximately the same earnings before interest and taxes in the standards case in the year after the compliance date of the amended standards as in the no-new-standards case. This scenario represents the lower bound to industry profitability under amended energy conservation standards.

A comparison of industry financial impacts under the two manufacturer markup scenarios is presented in section V.B.2.a of this document.

K. Emissions Analysis

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site (where applicable) combustion emissions of CO_2, NO_X, SO_2, and Hg. The second component estimates the impacts of potential standards on emissions of two additional greenhouse gases, CH_4 and N_2O, as well as the reductions in emissions of other gases due to ''upstream'' activities in the fuel production chain. These upstream activities comprise extraction, processing, and transporting fuels to the site of combustion.

The analysis of electric power sector emissions of CO_2, NO_X, SO_2, and Hg uses emissions intended to represent the marginal impacts of the change in electricity consumption associated with amended or new standards. The methodology is based on results published for the *AEO,* including a set of side cases that implement a variety of efficiency-related policies. The methodology is described in appendix 13A in the final rule TSD. The analysis presented in this notice uses projections from *AEO2023.* Power sector emissions of CH_4 and N_2O from fuel combustion are estimated using Emission Factors for Greenhouse Gas Inventories published by the Environmental Protection Agency (EPA).[178]

Site emissions of these gases were estimated using Emission Factors for Greenhouse Gas Inventories and, for NO_X and SO_2, emissions intensity factors from an EPA publication.[179]

FFC upstream emissions, which include emissions from fuel combustion during extraction, processing, and transportation of fuels, and ''fugitive'' emissions (direct leakage to the atmosphere) of CH_4 and CO_2, are estimated based on the methodology described in chapter 15 of the final rule TSD.

The emissions intensity factors are expressed in terms of physical units per MWh or MMBtu of site energy savings. For power sector emissions, specific emissions intensity factors are calculated by sector and end use. Total emissions reductions are estimated using the energy savings calculated in the national impact analysis.

1. Air Quality Regulations Incorporated in DOE's Analysis

DOE's no-new-standards case for the electric power sector reflects the *AEO,* which incorporates the projected impacts of existing air quality regulations on emissions. *AEO2023* reflects, to the extent possible, laws and regulations adopted through mid-November 2022, including the emissions control programs discussed in the following paragraphs and the Inflation Reduction Act.[180]

SO_2 emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap-and-trade programs. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (''D.C.''). (42 U.S.C. 7651 *et seq.*) SO_2 emissions from numerous States in the eastern half of the United States are also limited under the Cross-State Air Pollution Rule (''CSAPR''). 76 FR 48208 (Aug. 8, 2011). CSAPR requires these States to reduce certain emissions, including annual SO_2 emissions, and went into effect as of January 1, 2015.[181] The *AEO* incorporates implementation of CSAPR, including the update to the CSAPR ozone season program emission budgets and target dates issued in 2016. 81 FR 74504 (Oct. 26, 2016). Compliance with CSAPR is flexible among EGUs and is enforced through the use of tradable emissions allowances. Under existing EPA regulations, for states subject to SO_2 emissions limits under CSAPR, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the adoption of an efficiency standard could be used to permit offsetting increases in SO_2 emissions by another regulated EGU.

However, beginning in 2016, SO_2 emissions began to fall as a result of the Mercury and Air Toxics Standards (MATS) for power plants.[182] 77 FR 9304 (Feb. 16, 2012). The final rule establishes power plant emission standards for mercury, acid gases, and non-mercury metallic toxic pollutants. Because of the emissions reductions under the MATS, 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 another regulated EGU. Therefore, energy conservation standards that decrease electricity generation will generally reduce SO_2 emissions. DOE estimated SO_2 emissions reduction using emissions factors based on *AEO2023*.

CSAPR also established limits on NO_X emissions for numerous States in the eastern half of the United States. Energy conservation standards would have little effect on NO_X emissions in those States covered by CSAPR emissions limits if excess NO_X emissions allowances resulting from the lower electricity demand could be used to

[178] Available at *www.epa.gov/sites/production/files/2021-04/documents/emission-factors_apr2021.pdf* (last accessed July 12, 2021).

[179] U.S. Environmental Protection Agency. External Combustion Sources. In *Compilation of Air Pollutant Emission Factors.* AP–42. Fifth Edition. Volume I: Stationary Point and Area Sources. Chapter 1. Available at *www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors#Proposed/* (last accessed July 12, 2021).

[180] For further information, see the Assumptions to *AEO2023* report that sets forth the major assumptions used to generate the projections in the Annual Energy Outlook. Available at *www.eia.gov/outlooks/aeo/assumptions/* (last accessed January 2, 2024).

[181] CSAPR requires states to address annual emissions of SO_2 and NO_X, precursors to the formation of fine particulate matter ($PM_{2.5}$) pollution, in order to address the interstate transport of pollution with respect to the 1997 and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). CSAPR also requires certain states to address the ozone season (May–September) emissions of NO_X, a precursor to the formation of ozone pollution, in order to address the interstate transport of ozone pollution with respect to the 1997 ozone NAAQS. 76 FR 48208 (Aug. 8, 2011). EPA subsequently issued a supplemental rule that included an additional five states in the CSAPR ozone season program; 76 FR 80760 (Dec. 27, 2011) (Supplemental Rule), and EPA issued the CSAPR Update for the 2008 ozone NAAQS. 81 FR 74504 (Oct. 26, 2016).

[182] In order to continue operating, coal power plants must have either flue gas desulfurization or dry sorbent injection systems installed. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions.

permit offsetting increases in NO_X emissions from other EGUs. In such case, NO_X emissions would remain near the limit even if electricity generation goes down. Depending on the configuration of the power sector in the different regions and the need for allowances, however, NO_X emissions might not remain at the limit in the case of lower electricity demand. That would mean that standards might reduce NO_X emissions in covered States. Despite this possibility, DOE has chosen to be conservative in its analysis and has maintained the assumption that standards will not reduce NO_X emissions in States covered by CSAPR. Standards would be expected to reduce NO_X emissions in the States not covered by CSAPR. DOE used *AEO2023* data to derive NO_X emissions factors for the group of States not covered by CSAPR.

The MATS limit mercury emissions from power plants, but they do not include emissions caps and, as such, DOE's energy conservation standards would be expected to slightly reduce Hg emissions. DOE estimated mercury emissions reduction using emissions factors based on *AEO2023,* which incorporates the MATS.

EEI commented that electric companies are already reducing greenhouse gas emissions via clean energy initiatives such as utilizing more renewable energy technology. (EEI, No. 135 at pp. 7–8) Several other stakeholders similarly commented that utility companies are actively reducing greenhouse gas emissions and already utilize carbon-free energy sources. (Idaho Falls Power, No. 77 at p. 2; Fall River, No. 83 at p. 2; WEC, No. 118 at p. 3)

In response to EEI and other utility stakeholders, DOE notes that the emissions factors are determined by AEO, which accounts for declining future carbon emissions due increased renewable generation.

L. Monetizing Emissions Impacts

As part of the development of this final rule, for the purpose of complying with the requirements of Executive Order 12866, DOE considered the estimated monetary benefits from the reduced emissions of CO_2, CH_4, N_2O, NO_X, and SO_2 that are expected to result from each of the TSLs considered. In order to make this calculation analogous to the calculation of the NPV of consumer benefit, DOE considered the reduced emissions expected to result over the lifetime of products shipped in the projection period for each TSL. This section summarizes the basis for the values used for monetizing the emissions benefits and presents the values considered in this final rule.

To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

1. Monetization of Greenhouse Gas Emissions

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

DOE exercises its own judgment in presenting monetized climate benefits as recommended by applicable Executive orders, and DOE would reach the same conclusion presented in this rulemaking in the absence of the social cost of greenhouse gases. That is, the social costs of greenhouse gases, whether measured using the February 2021 interim estimates presented by the IWG on the Social Cost of Greenhouse Gases or by another means, did not affect the rule ultimately adopted by DOE.

DOE estimated the global social benefits of CO_2, CH_4, and N_2O reductions using SC–GHG values that were based on the interim values presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990,* published in February 2021 by the IWG (''February 2021 SC–GHG TSD''). The SC–GHG is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, the SC–GHG includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–GHG, therefore, reflects the societal value of reducing emissions of the gas in question by 1 metric ton. The SC–GHG is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2, N_2O, and CH_4 emissions. As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees that the interim SC–GHG estimates represent the most appropriate estimate of the SC–GHG until revised estimates have been developed reflecting the latest, peer-reviewed science. DOE continues to evaluate recent developments in the scientific literature, including the updated SC–GHG estimates published by the EPA in December 2023 within their rulemaking on oil and natural gas sector sources.[183] For this rulemaking, DOE used these updated SC–GHG values to conduct a sensitivity analysis of the value of GHG emissions reductions associated with alternative standards for distribution transformers (see section IV.L.1.c of this document).

The SC–GHG estimates presented here were developed over many years, using peer-reviewed methodologies, a transparent process, the best science available at the time of that process, and input from the public. Specifically, in 2009, the IWG, which included DOE and other Executive branch agencies and offices, was established to ensure that agencies were using the best available science and to promote consistency in the SC–CO_2 values used across agencies. The IWG published SC–CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity—a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM. In August 2016 the IWG published estimates of the

[183] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review'': EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. Washington, DC: U.S. EPA. *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/epas-final-rule-oil-and-natural-gas.*

SC–CH_4 and SC–N_2O using methodologies that are consistent with the methodology underlying the SC–CO_2 estimates. The modeling approach that extends the IWG SC–CO_2 methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The SC–CH_4 and SC–N_2O estimates were developed by Marten *et al.*[184] and underwent a standard double-blind peer review process prior to journal publication. In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC–CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC–CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, ''Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide,'' and recommended specific criteria for future updates to the SC–CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process.[185] Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC–CO_2 estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A–4, ''including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates'' (E.O. 13783, Section 5(c)). Benefit-cost analyses following E.O. 13783 used SC–GHG estimates that attempted to focus on the U.S.-specific share of climate change damages as estimated by the models and were calculated using two discount rates recommended by Circular A–4, 3 percent and 7 percent. All other methodological decisions and model versions used in SC–GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the recommendations in the National Academies 2017 report. The IWG was tasked with first reviewing the SC–GHG estimates currently used in Federal analyses and publishing interim estimates within 30 days of the E.O. that reflect the full impact of GHG emissions, including by taking global damages into account. The interim SC–GHG estimates published in February 2021 are used here to estimate the climate benefits for this rulemaking. The E.O. instructs the IWG to undertake a fuller update of the SC–GHG estimates that takes into consideration the advice in the National Academies 2017 report and other recent scientific literature. The February 2021 SC–GHG TSD provides a complete discussion of the IWG's initial review conducted under E.O. 13990. In particular, the IWG found that the SC–GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways.

First, the IWG found that the SC–GHG estimates used under E.O. 13783 fail to fully capture many climate impacts that affect the welfare of U.S. citizens and residents, and those impacts are better reflected by global measures of the SC–GHG. Examples of omitted effects from the E.O. 13783 estimates include direct effects on U.S. citizens, assets and investments located abroad, supply chains, U.S. military assets and interests abroad, tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. If the United States does not consider impacts on other countries, it is difficult to convince other countries to consider the impacts of their emissions on the United States. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages. As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees with this assessment and, therefore, in this final rule DOE centers attention on a global measure of SC–GHG. This approach is the same as that taken in DOE regulatory analyses from 2012 through 2016. A robust estimate of climate damages that accrue only to U.S. citizens and residents does not currently exist in the literature. As explained in the February 2021 SC–GHG TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature. As noted in the February 2021 SC–GHG TSD, the IWG will continue to review developments in the literature, including more robust methodologies for estimating a U.S.-specific SC–GHG value, and explore ways to better inform the public of the full range of carbon impacts. As a member of the IWG, DOE will continue to follow developments in the literature pertaining to this issue.

Second, the IWG found that the use of the social rate of return on capital (estimated to be 7 percent under OMB's 2003 Circular A–4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC–GHG. Consistent with the findings of the National Academies and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context,[186] and it

[184] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. Incremental CH_4 and N_2O mitigation benefits consistent with the U.S. Government's SC–CO_2 estimates. *Climate Policy.* 2015. 15(2): pp. 272–298.

[185] National Academies of Sciences, Engineering, and Medicine. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* 2017. The National Academies Press: Washington, DC. *nap.nationalacademies.org/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of.*

[186] Interagency Working Group on Social Cost of Carbon. *Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866.* 2010. United States Government. *www.epa.gov/sites/default/files/2016-12/documents/scc_tsd_2010.pdf* (last accessed April 15, 2022.); Interagency Working Group on Social Cost of Carbon. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* 2013. *www.federalregister.gov/documents/2013/11/26/2013-28242/technical-support-document-technical-update-of-the-social-cost-of-carbon-for-regulatory-impact* (last accessed April 15, 2022.); *Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. Technical Support Document: Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis—Under Executive Order 12866.* August 2016. *www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf* (last accessed January 18, 2022.);

Continued

recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.

Furthermore, the damage estimates developed for use in the SC–GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A–4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC–GHG. DOE agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. DOE also notes that while OMB's 2003 Circular A–4 recommends using 3-percent and 7-percent discount rates as ''default'' values, Circular A–4 also reminds agencies that ''different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions.'' On discounting, Circular A–4 recognizes that ''special ethical considerations arise when comparing benefits and costs across generations,'' and Circular A–4 acknowledges that analyses may appropriately ''discount future costs and consumption benefits . . . at a lower rate than for intragenerational analysis.'' In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, DOE, and the other IWG members recognized that ''Circular A–4 is a living document'' and ''the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A–4 itself.'' Thus, DOE concludes that a 7-percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this analysis.

To calculate the present and annualized values of climate benefits, DOE uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 SC–GHG TSD recommends ''to ensure internal consistency—*i.e.,* future damages from climate change using the SC–GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate.'' DOE has also consulted the National Academies' 2017 recommendations on how SC–GHG estimates can ''be combined in RIAs with other cost and benefits estimates that may use different discount rates.'' The National Academies reviewed several options, including ''presenting all discount rate combinations of other costs and benefits with [SC–GHG] estimates.''

As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees with the above assessment and will continue to follow developments in the literature pertaining to this issue. While the IWG works to assess how best to incorporate the latest, peer-reviewed science to develop an updated set of SC–GHG estimates, it set the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 SC–GHG TSD, the IWG has recommended that agencies revert to the same set of four values drawn from the SC–GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and were subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values recommended for use in benefit-cost analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3-percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change. As explained in the February 2021 SC–GHG TSD, and DOE agrees, this update reflects the immediate need to have an operational SC–GHG for use in regulatory benefit-cost analyses and other applications that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

There are a number of limitations and uncertainties associated with the SC–GHG estimates. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower.[187] Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their ''damage functions''—*i.e.,* the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages—lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections. The modeling limitations do not all work in the same direction in terms of their influence on the SC–CO_2 estimates. However, as discussed in the February 2021 SC–GHG TSD, the IWG has recommended that, taken together, the limitations suggest that the interim SC–GHG estimates used in this final rule likely underestimate the damages from GHG emissions. DOE concurs with this assessment.

DOE's derivations of the SC–CO_2, SC–N_2O, and SC–CH_4 values used for this NOPR are discussed in the following sections, and the results of DOE's analyses estimating the benefits of the reductions in emissions of these GHGs are presented in section V.B.6 of this document.

a. Social Cost of Carbon

The SC–CO_2 values used for this final rule were based on the values developed for the February 2021 SC–GHG TSD,

Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. *Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide.* August 2016. *www.epa.gov/sites/default/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf* (last accessed January 18, 2022.).

[187] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at *www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.*

which are shown in Table IV.30 in 5-year increments from 2020 to 2050. The set of annual values that DOE used, which was adapted from estimates published by EPA,[188] is presented in appendix 14A of the final rule TSD. These estimates are based on methods, assumptions, and parameters identical to the estimates published by the IWG (which were based on EPA modeling), and include values for 2051 to 2070. DOE expects additional climate benefits to accrue for products still operating after 2070, but a lack of available SC–CO_2 estimates for emissions years beyond 2070 prevents DOE from monetizing these potential benefits in this analysis.

Table IV.30. Annual SC-CO_2 Values from 2021 Interagency Update, 2020–2050 (2020$ per Metric Ton CO_2)

Year	Discount Rate and Statistic			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
2020	14	51	76	152
2025	17	56	83	169
2030	19	62	89	187
2035	22	67	96	206
2040	25	73	103	225
2045	28	79	110	242
2050	32	85	116	260

DOE multiplied the CO_2 emissions reduction estimated for each year by the SC–CO_2 value for that year in each of the four cases. DOE adjusted the values to 2022$ using the implicit price deflator for gross domestic product (GDP) from the Bureau of Economic Analysis. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain the SC–CO_2 values in each case.

b. Social Cost of Methane and Nitrous Oxide

The SC–CH_4 and SC–N_2O values used for this final rule were based on the values developed for the February 2021 SC–GHG TSD. Table IV.31 shows the updated sets of SC–CH_4 and SC–N_2O estimates from the latest interagency update in 5-year increments from 2020 to 2050. The full set of annual values used is presented in appendix 14A of the final rule TSD. To capture the uncertainties involved in regulatory impact analysis, DOE has determined it is appropriate to include all four sets of SC–CH_4 and SC–N_2O values, as recommended by the IWG. DOE derived values after 2050 using the approach described above for the SC–CO_2.

Table IV.31. Annual SC-CH_4 and SC-N_2O Values from 2021 Interagency Update, 2020–2050 (2020$ per Metric Ton)

Year	SC-CH_4				SC-N_2O			
	Discount Rate and Statistic				Discount Rate and Statistic			
	5%	3%	2.5%	3%	5%	3%	2.5 %	3%
	Average	Average	Average	95th percentile	Average	Average	Average	95th percentile
2020	670	1500	2000	3900	5800	18000	27000	48000
2025	800	1700	2200	4500	6800	21000	30000	54000
2030	940	2000	2500	5200	7800	23000	33000	60000
2035	1100	2200	2800	6000	9000	25000	36000	67000
2040	1300	2500	3100	6700	10000	28000	39000	74000
2045	1500	2800	3500	7500	12000	30000	42000	81000
2050	1700	3100	3800	8200	13000	33000	45000	88000

DOE multiplied the CH_4 and N_2O emissions reduction estimated for each year by the SC–CH_4 and SC–N_2O estimates for that year in each of the cases. DOE adjusted the values to 2022$ using the implicit price deflator for GDP from the Bureau of Economic Analysis. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the cases using the specific discount rate that had been used to obtain the SC–CH_4 and SC–N_2O estimates in each case.

c. Sensitivity Analysis Using EPA's New SC–GHG Estimates

In the regulatory impact analysis of EPA's December 2023 Final Rulemaking, ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas

[188] *See* EPA, ''Revised 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards: Regulatory Impact Analysis,'' Washington, DC, December 2021. Available at *nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013ORN.pdf* (last accessed Feb. 21, 2023).

Sector Climate Review,'' EPA estimated climate benefits using a new set of Social Cost of Greenhouse Gas (SC–GHG) estimates. These estimates incorporate recent research addressing recommendations of the National Academies (2017), responses to public comments on an earlier sensitivity analysis using draft SC–GHG estimates, and comments from a 2023 external peer review of the accompanying technical report.[189]

The full set of annual values is presented in appendix 14C of the direct final rule TSD. Although DOE continues to review EPA's estimates, for this rulemaking, DOE used these new SC–GHG values to conduct a sensitivity analysis of the value of GHG emissions reductions associated with alternative standards for distribution transformers. This sensitivity analysis provides an expanded range of potential climate benefits associated with amended standards. The final year of EPA's new estimates is 2080; therefore, DOE did not monetize the climate benefits of GHG emissions reductions occurring after 2080.

The results of the sensitivity analysis are presented in appendix 14C of the final rule TSD. The overall climate benefits are larger when using EPA's higher SC–GHG estimates, compared to the climate benefits using the more conservative IWG SC–GHG estimates. However, DOE's conclusion that the standards are economically justified remains the same regardless of which SC–GHG estimates are used.

2. Monetization of Other Emissions Impacts

For the final rule, DOE estimated the monetized value of NO_X and SO_2 emissions reductions from electricity generation using benefit-per-ton estimates for that sector from the EPA's Benefits Mapping and Analysis Program. [190] DOE used EPA's values for $PM_{2.5}$-related benefits associated with NO_X and SO_2 and for ozone-related benefits associated with NO_X for 2025 and 2030, 2035, and 2040, calculated with discount rates of 3 percent and 7 percent. DOE used linear interpolation to define values for the years not given in the 2025 to 2040 period; for years beyond 2040, the values are held constant (rather than extrapolated) to be conservative. DOE combined the EPA regional benefit-per-ton estimates with regional information on electricity consumption and emissions from *AEO2023* to define weighted-average national values for NO_X and SO_2.

DOE received the following comments regarding its monetization of emissions impacts.

The Chamber of Commerce urged DOE to reconsider the use of the SC–GHG estimates in this rulemaking based on three core concerns. First, the Chamber of Commerce commented that before DOE considers applying the SC–GHG estimates to the proposed rule (and, likewise, to any final rule resulting from this rulemaking), the SC–GHG estimates should be subject to a proper administrative process, including a full and fair public comment process, as well as a robust independent peer review. Second, the Chamber of Commerce stated that there are statutory limitations on using the SC–GHG estimates, and it urged DOE to fully consider the applicable limits before applying the estimates. Third, the Chamber of Commerce urged DOE to carefully consider whether the ''major questions'' doctrine precludes the application of the SC–GHG estimates in the proposed rule given the political and economic significance of the estimates. (Chamber of Commerce, No. 88 at p. 6)

In response, DOE first notes that it would reach the same conclusion presented in this final rule in the absence of the social cost of greenhouse gases. As it relates to the Chamber of Commerce's first comment, DOE reiterates that the SC–GHG estimates were developed using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and input from the public.

Regarding possible statutory limitations on using the SC–GHG estimates, DOE maintains that environmental and public health benefits associated with the more efficient use of energy, including those connected to global climate change, are important to take into account when considering the ''need for national energy . . . conservation,'' which is one of the factors that EPCA requires DOE to evaluate in determining whether a potential energy conservation standard is economically justified. (42 U.S.C. 6295(o)(2)(B)(i)(VI)); *Zero Zone, Inc.* v. *United States DOE,* 832 F.3d 654, 677 (7th Cir. 2016) (pointing to 42 U.S.C. 6295(o)(2)(B)(i)(VI) in concluding that ''[w]e have no doubt that Congress intended that DOE have the authority under the EPCA to consider the reduction in SCC.'') DOE has been analyzing the monetized emissions impacts from its rules, for over 10 years. In addition, Executive Order 13563, ''Improving Regulation and Regulatory Review,'' which was re-affirmed on January 20, 2021, states that each agency, among other things, must, to the extent permitted by law: ''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).'' E.O. 13563, Section 1(b). Furthermore, as noted previously, E.O. 13990, ''Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,'' re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the recommendations of the National Academies. As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees that the interim SC–GHG estimates represent the most appropriate estimate of the SC–GHG until revised estimates have been developed reflecting the latest, peer-reviewed science. For these reasons, DOE includes monetized emissions reductions in its evaluation of potential standard levels.

Regarding whether the ''major questions'' doctrine precludes the application of the SC–GHG estimates in proposed or final rules, DOE notes that the ''major questions'' doctrine raised by the Chamber of Commerce applies only in ''extraordinary cases'' concerning Federal agencies claiming highly consequential regulatory authority beyond what Congress could reasonably be understood to have granted. *West Virginia* v. *EPA,* 142 S. Ct. 2587, 2609 (2022); *N.C. Coastal Fisheries Reform Grp.* v. *Capt. Gaston LLC,* 2023 U.S. App. LEXIS 20325, *6–8 (4th Cir., Aug. 7, 2023) (listing the hallmarks courts have recognized to invoke the major questions doctrine, such as a hesitancy ''to recognize new-found powers in old statutes against a backdrop of an agency failing to invoke them previously,'' ''when the asserted power raises federalism concerns,'' or ''when the asserted authority falls outside the agency's traditional expertise, . . . or is found in an 'ancillary provision.' ''). DOE has clear authorization under EPCA to regulate the energy efficiency or energy use of a variety of COMMERCIAL AND INDUSTRIAL

[189] For further information about the methodology used to develop these values, public comments, and information pertaining to the peer review, see *https://www.epa.gov/environmental-economics/scghg.*

[190] U.S. Environmental Protection Agency. Estimating the Benefit per Ton of Reducing Directly-Emitted $PM_{2.5}$, $PM_{2.5}$ Precursors and Ozone Precursors from 21 Sectors. *www.epa.gov/benmap/estimating-benefit-ton-reducing-directly-emitted-pm25-pm25-precursors-and-ozone-precursors.*

equipment, including distribution transformers. Although DOE routinely conducts an analysis of the anticipated emissions impacts of potential energy conservation standards under consideration, see, *e.g., Zero Zone,* 832 F.3d at 677, DOE does not purport to regulate such emissions, and as stated elsewhere in this document, DOE's selection of standards would be the same without consideration of emissions. Where DOE applied the factors it was tasked to consider under EPCA and the rule is justified even absent use of the SC–GHG analysis, the major questions doctrine has no bearing.

The Institute for Policy Integrity (IPI) commented that DOE appropriately applies the social cost estimates developed by the IWG to its analysis of climate benefits. IPI stated that these values are widely agreed to underestimate the full social costs of greenhouse gas emissions, but for now they remain appropriate to use as conservative estimates. (IPI, No. 123 at p. 1)

DOE agrees that the interim SC–GHG values applied for this final rule are conservative estimates. In the February 2021 SC–GHG TSD, the IWG stated that the models used to produce the interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature. For these same impacts, the science underlying their ''damage functions'' lags behind the most recent research. In the judgment of the IWG, these and other limitations suggest that the range of four interim SC–GHG estimates presented in the TSD likely underestimate societal damages from GHG emissions. The IWG is in the process of assessing how best to incorporate the latest peer-reviewed science and the recommendations of the National Academies to develop an updated set of SC–GHG estimates, and DOE remains engaged in that process.

IPI suggested that DOE should state that criticisms of the social cost of greenhouse gases are moot in this rulemaking because the proposed rule is justified without them. DOE agrees that the proposed rule is economically justified without including climate benefits associated with reduced GHG emissions. (IPI, No. 123 at p. 2)

IPI commented that DOE should consider applying sensitivity analysis using EPA's draft climate-damage estimates released in November 2022, as EPA's work faithfully implements the road map laid out in 2017 by the National Academies of Sciences and applies recent advances in the science and economics on the costs of climate change. (IPI, No. 123 at p. 1)

DOE typically does not conduct analyses using draft inputs that are still under review. DOE notes that because the EPA's draft estimates are considerably higher than the IWG's interim SC–GHG values applied for this final rule, an analysis that used the draft values would result in significantly greater climate-related benefits. However, such results would not affect DOE's decision in this proposed rule.

M. Utility Impact Analysis

The utility impact analysis estimates the changes in installed electrical capacity and generation projected to result for each considered TSL. The analysis is based on published output from the NEMS associated with *AEO2023.* NEMS produces the *AEO* Reference case, as well as a number of side cases that estimate the economy-wide impacts of changes to energy supply and demand. For the current analysis, impacts are quantified by comparing the levels of electricity sector generation, installed capacity, fuel consumption and emissions in the *AEO2023* Reference case and various side cases. Details of the methodology are provided in the appendices to chapters 13 and 15 of the final rule TSD.

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

N. Employment Impact Analysis

DOE considers employment impacts in the domestic economy as one factor in selecting a standard. Employment impacts from new or amended energy conservation standards include both direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the products 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 net jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, caused by (1) reduced spending by consumers on energy, (2) reduced spending on new energy supply by the utility industry, (3) increased consumer spending on the products to which the new standards apply and other goods and services, and (4) the effects of those three factors throughout the economy.

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.[191] 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, the BLS data suggest that net national employment may increase due to shifts in economic activity resulting from energy conservation standards.

DOE estimated indirect national employment impacts for the standard levels considered in this final rule using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 4 (ImSET).[192] 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

[191] *See* U.S. Department of Commerce–Bureau of Economic Analysis. *Regional Input-Output Modeling System (RIMS II) User's Guide.* Available at: *apps.bea.gov/resources/methodologies/RIMSII-user-guide* (last accessed Sept. 12, 2022).

[192] Livingston, O. V., S. R. Bender, M. J. Scott, and R. W. Schultz. *ImSET 4.0: Impact of Sector Energy Technologies Model Description and User's Guide.* 2015. Pacific Northwest National Laboratory: Richland, WA. PNNL–24563.

characterize economic flows among 187 sectors most relevant to industrial, commercial, and residential building energy use.

DOE notes that ImSET is not a general equilibrium forecasting model, and that there are 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 overestimate actual job impacts over the long run for this rule. Therefore, DOE used ImSET only to generate results for near-term timeframes (2034), where these uncertainties are reduced. In the long-term DOE expects that the net effect from amended standards will be an increased shift towards consumer goods from the utility sector. For more details on the employment impact analysis, see chapter 16 of the final rule TSD.

V. Analytical Results and Conclusions

The following section addresses the results from DOE's analyses with respect to the considered energy conservation standards for distribution transformers. It addresses the TSLs examined by DOE, the projected impacts of each of these levels if adopted as energy conservation standards for distribution transformers, and the standards levels that DOE is adopting in this final rule. Additional details regarding DOE's analyses are contained in the final rule TSD supporting this document.

Table V.1 Equipment Classes Analyzed for Distribution Transformers

EC* #	Insulation	Voltage	Phase	BIL Rating	kVA Range
EC1A	Liquid-Immersed	Medium	Single	-	>100 kva and ≤833 kVA
EC1B	Liquid-Immersed	Medium	Single	-	≥10 kva and ≤100 kVA
EC2A	Liquid-Immersed	Medium	Three	-	≥15 kva and <500 kVA
EC2B	Liquid-Immersed	Medium	Three	-	≥500 kva and ≤5000 kVA
EC3	Dry-Type	Low	Single	-	15-333 kVA
EC4	Dry-Type	Low	Three	-	15-1000 kVA
EC5	Dry-Type	Medium	Single	20-45kV BIL	15-833 kVA
EC6	Dry-Type	Medium	Three	20-45kV BIL	15-5000 kVA
EC7	Dry-Type	Medium	Single	46-95kV BIL	15-833 kVA
EC8	Dry-Type	Medium	Three	46-95kV BIL	15-5000 kVA
EC9	Dry-Type	Medium	Single	≥ 96kV BIL	75-833 kVA
EC10	Dry-Type	Medium	Three	≥ 96kV BIL	225-5000 kVA
EC12†	Submersible Transformers				

* EC = Equipment Class

† EC11 corresponds to mining distribution transformers which were not analyzed as part of this rulemaking and are not currently subject to efficiency standards

A. Trial Standard Levels

In general, DOE typically evaluates potential new or amended standards for products and equipment by grouping individual efficiency levels for each class into TSLs. Use of TSLs allows DOE to identify and consider manufacturer cost interactions between the equipment classes, to the extent that there are such interactions, and price elasticity of consumer purchasing decisions that may change when different standard levels are set.

In the analysis conducted for this final rule, DOE analyzed the benefits and burdens of five TSLs for distribution transformers. DOE developed TSLs that combine efficiency levels for each analyzed equipment class and kVA rating. For this analysis, DOE defined its efficiency levels as a percentage reduction in baseline losses (*See* section IV.F.2 of this document). To create TSLs, DOE maintained this approach and directly mapped ELs to TSLs, for low-voltage dry-type and medium-voltage dry-type distribution transformers. To create TSLs for liquid-immersed distribution transformers other than submersible distribution transformers, DOE directly mapped ELs to TSLs for TSL 1, 2, 4, and 5. For TSL 3, DOE considered a TSL wherein class 1A and 2A were mapped to EL 4 and equipment class 1B and 2B were mapped to EL 2, which corresponds to a TSL where a diversity of domestically produced core materials are cost competitive without requiring substantial investments in new capacity for core materials.

DOE notes that all TSLs align with the TSLs from the NOPR except for liquid-immersed TSL 3. In the NOPR, DOE mapped EL 3 to TSL 3.

In this final rule, DOE modified TSL 3 for liquid-immersed distribution transformers such that for equipment classes 1A, 1B, 2A, and 2B TSL3 is a combination wherein equipment classes 1B and 2B are set at EL2, and 1A and 2A are set at EL4. This ensures that capacity for amorphous ribbon increases driven by equipment classes 1A and 2A; and leaves a considerable portion of the market at efficiency levels where GOES remains cost competitive, equipment classes 1B and 2B. Further, TSL 3 ensures that units that are more likely to have high currents (equipment class 2B) and units that are more likely to be overloaded (equipment class 1B), have additional flexibility in meeting efficiency standards to accommodate this consumer utility, as discussed in sections IV.A.2.b and IV.A.2.c of this document. For all other equipment classes TSL 3 is identical to that which was presented in the January 2023 NOPR. DOE notes that the ELs used in the final rule correspond to an identical reduction in rated losses as the ELs used in the January 2023 NOPR. However, the grouping of these ELs by equipment class has been modified in response to stakeholder feedback. TSL3 is intended to reflect stakeholder concerns that substantial amorphous core production could lead to near term supply chain constraints given the investment required to transition the entire U.S. market to amorphous cores.

DOE notes that both EL 3 and EL 4 for liquid-immersed distribution transformers generally are met with substantial amorphous core production and therefore would have similar consumer and manufacturer impacts along with similar concerns regarding supply chain and domestic core production. DOE considered, and adopts, TSL 3 in this final rule to maximize the energy savings and consumer benefits without requiring that the entire market transition to amorphous cores, which, as discussed, would not be economically justified.

Liquid-immersed submersible distribution transformers remain at baseline for all TSLs except max-tech. For submersible distribution transformers, being able to fit in an existing vault is a performance related feature of significant consumer utility and these transformers often serve high density applications. DOE recognizes that beyond some size increase a vault replacement may be necessary, however, DOE lacks sufficient data as to where exactly that vault replacement is needed. In order to maintain the consumer utility associated with submersible transformers, DOE has taken the conservative approach of not considering TSLs for submersible transformers aside from max-tech. DOE presents the results for the TSLs in this document, while the results for all efficiency levels that DOE analyzed are in the final rule TSD.

Table V.2 presents the TSLs and the corresponding efficiency levels that DOE has identified for potential amended energy conservation standards for distribution transformers. TSL 5 represents the maximum technologically feasible (''max-tech'') energy efficiency for all product classes. TSL 4 represents a loss reduction over baseline of 20 percent for liquid-immersed transformers, except submersible liquid-immersed transformers which remain at baseline; a 40 and 30 percent reduction in baseline losses for single-, and three-phase low-voltage distribution transformers, respectively; and a 30 percent reduction in baseline losses for all medium-voltage dry-type distribution transformers. TSL 3 represents a loss reduction over baseline of 5 percent for liquid-immersed transformers for single-phase transformers less than or equal to 100 kVA and three-phase transformers greater than or equal to 500 kVA and a loss reduction over baseline of 20 percent for all other liquid-immersed transformers, except submersible liquid-immersed transformers which remain at baseline; a 30 and 20 percent reduction in baseline losses for single-, and three-phase low-voltage distribution transformers, respectively; and a 20 percent reduction in baseline losses for all medium-voltage dry-type distribution transformers. TSL 2 represents a loss reduction over baseline of 5 percent for liquid-immersed transformers, except submersible liquid-immersed transformers which remain at baseline; a 20 and 10 percent reduction in baseline losses for single-, and three-phase low-voltage distribution transformers, respectively; and a 10 percent reduction in baseline losses for all medium-voltage dry-type distribution transformers. TSL 1 represents a loss reduction over baseline of 2.5 percent for liquid-immersed transformers, except submersible liquid-immersed transformers which remain at baseline; a 10 and 5 percent reduction in baseline losses for single-, and three-phase low-voltage distribution transformers, respectively; and a 5 percent reduction in baseline losses for all medium-voltage dry-type distribution transformers.

Table V.2 Efficiency Level to Trail Standard Level Mapping for Distribution Transformers

Equipment Category	EC	RU	kVA Range	Phases	BIL	Trial Standard Level				
						1	**2**	**3**	**4**	**5**
Liquid-Immersed Distribution Transformers	1A	1A	>100	1	*All*	1	2	4	4	5
	1A	2A	>100	1	*All*	1	2	4	4	5
	1A	3	*All*	1	*All*	1	2	4	4	5
	1B	1B	≤100	1	*All*	1	2	2	4	5
	1B	2B	≤100	1	*All*	1	2	2	4	5
	2A	4A	<500	3	*All*	1	2	4	4	5
	2A	4B	≥500	3	*All*	1	2	2	4	5
	2B	5	*All*	3	*All*	1	2	2	4	5
	2B	17	*All*	3	*All*	1	2	2	4	5
	12	15	*All*	3	*All*	0	0	0	0	5
	12	16	*All*	3	*All*	0	0	0	0	5
Low-Voltage Dry-Type Distribution Transformer	3	6	*All*	1	*All*	1	2	3	4	5
	4	7	*All*	3	*All*	1	2	3	4	5
	4	8	*All*	3	*All*	1	2	3	4	5
Medium-Voltage Dry-Type Distribution Transformer	5	9V*	*All*	1	< 46 kV	1	2	3	4	5
	5	10V	*All*	1	< 46 kV	1	2	3	4	5
	6	9	*All*	3	< 46 kV	1	2	3	4	5
	6	10	*All*	3	< 46 kV	1	2	3	4	5
	7	11V	*All*	1	≥ 46 and < 96 kV	1	2	3	4	5
	7	12V	*All*	1	≥ 46 and < 96 kV	1	2	3	4	5
	8	11	*All*	3	≥ 46 and < 96 kV	1	2	3	4	5
	8	12	*All*	3	≥ 46 and < 96 kV	1	2	3	4	5
	8	18	*All*	3	≥ 46 and < 96 kV	1	2	3	4	5
	9	13V	*All*	1	≥ 96 kV	1	2	3	4	5
	9	14V	*All*	1	≥ 96 kV	1	2	3	4	5
	10	13	*All*	3	≥ 96 kV	1	2	3	4	5
	10	14	*All*	3	≥ 96 kV	1	2	3	4	5
	10	19	*All*	3	≥ 96 kV	1	2	3	4	5

DOE constructed the TSLs for this final rule to include ELs representative of ELs with similar characteristics (*i.e.,* using similar technologies and/or efficiencies, and having roughly comparable equipment availability) and taking into consideration the domestic electrical steel and amorphous capacity and conversion cost impacts associated with various ELs. The use of representative ELs provided for greater distinction between the TSLs. While representative ELs were included in the TSLs, DOE considered all efficiency levels as part of its analysis.[193]

[193] Efficiency levels that were analyzed for this final rule are discussed in section IV.F.2 of this

B. Economic Justification and Energy Savings

1. Economic Impacts on Individual Consumers

DOE analyzed the economic impacts on distribution transformer consumers by looking at the effects that potential amended standards at each TSL would have on the LCC and PBP. DOE also examined the impacts of potential standards on selected consumer subgroups. These analyses are discussed in the following sections.

a. Life-Cycle Cost and Payback Period

In general, higher-efficiency products affect consumers in two ways: (1) purchase price increases and (2) annual operating costs decrease. Inputs used for calculating the LCC and PBP include total installed costs (*i.e.,* product price plus installation costs), and operating costs (*i.e.,* annual energy use, energy prices, energy price trends, repair costs, and maintenance costs). The LCC calculation also uses product lifetime and a discount rate. Chapter 8 of the final rule TSD provides detailed information on the LCC and PBP analyses.

The following sections show the LCC and PBP results for the TSLs considered for each product class. In the first of each pair of tables, the simple payback is measured relative to the baseline product. In the second table, the impacts are measured relative to the efficiency distribution in the in the no-new-standards case in the compliance year (*see* section IV.F.10 of this document). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of the baseline product and the average LCC at each TSL. The savings refer only to consumers who are affected by a standard at a given TSL. Those who already purchase a product with efficiency at or above a given TSL are not affected. Consumers for whom the LCC increases at a given TSL experience a net cost.

Liquid-Immersed Distribution Transformer

Table V.3 Average LCC and PBP Results for Equipment Class 1A: Single-phase greater than 100 kVA

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	10,687	238	4,744	15,431	-	32.0
1	10,722	232	4,623	15,345	3.8	32.0
2	10,830	229	4,555	15,385	19.1	32.0
3	11,690	149	3,088	14,778	10.7	32.0
4	11,690	149	3,088	14,778	10.7	32.0
5	15,442	132	2,668	18,111	42.1	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3.

Table V.4 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 1A: Single-phase greater than 100 kVA

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	90	37.8
2	49	55.7
3	657	27.5
4	657	27.5
5	-2,686	89.0

* The savings represent the average LCC for affected consumers.

document. Results by efficiency level are presented in TSD chapters 8, 10, and 12.

Table V.5 Average LCC and PBP Results for Equipment Class 1B: Single-phase less than or equal to 100 kVA

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	2,394	66	1,305	3,699	-	32.0
1	2,394	64	1,271	3,665	6.9	32.0
2	2,402	63	1,251	3,653	19.5	32.0
3	2,402	63	1,251	3,653	19.5	32.0
4	2,545	41	838	3,383	7.4	32.0
5	3,165	36	721	3,886	28.1	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3.

Table V.6 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 1B: Single-phase less than or equal to 100 kVA

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	36	29.3
2	48	28.5
3	48	28.5
4	317	7.1
5	-187	59.3

* The savings represent the average LCC for affected consumers.

Table V.7 Average LCC and PBP Results for Equipment Class 2A: Three-phase less than 500 kVA

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	11,728	220	4,376	16,104	-	32.1
1	11,755	217	4,312	16,067	8.4	32.1
2	11,870	211	4,190	16,059	14.7	32.1
3	12,501	136	2,777	15,278	9.2	32.1
4	12,501	136	2,777	15,278	9.2	32.1
5	13,114	128	2,586	15,701	15.1	32.1

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3.

Table V.8 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 2A: Three-phase less than 500 kVA

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	75	15.3
2	48	38.4
3	851	7.1
4	851	7.1
5	407	28.7

* The savings represent the average LCC for affected consumers.

Table V.9 Average LCC and PBP Results for Equipment Class 2B: Three-phase greater than or equal to 500 kVA

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	40,160	1,538	30,859	71,019	-	32.0
1	40,554	1,495	29,989	70,543	9.0	32.0
2	41,959	1,422	28,578	70,537	14.6	32.0
3	41,959	1,422	28,578	70,537	14.6	32.0
4	43,662	1,064	22,078	65,740	9.0	32.0
5	55,241	924	18,758	73,999	19.3	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3.

Table V.10 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 2B: Three-phase greater than or equal to 500 kVA

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	843	15.0
2	498	39.6
3	498	39.6
4	5,301	7.6
5	-2,977	40.1

* The savings represent the average LCC for affected consumers.

Table V.11 Average LCC and PBP Results for Equipment Class 12: Submersibles

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	160,067	1,828	37,168	197,235	-	32.0
1	160,067	1,828	37,168	197,235	-	32.0
2	160,067	1,828	37,168	197,235	-	32.0
3	160,067	1,828	37,168	197,235	-	32.0
4	160,067	1,828	37,168	197,235	-	32.0
5	171,352	1,205	25,118	196,470	14.8	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.12 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 12: Submersibles

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	-	-
2	-	-
3	-	-
4	-	-
5	770	45.2

* The savings represent the average LCC for affected consumers.

Table V.13 Average LCC and PBP Results for Equipment Class 3

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	2,817	148	2,347	5,164	-	31.9
1	2,816	138	2,194	5,010	instant	31.9
2	2,890	127	2,022	4,911	3.6	31.9
3	3,098	110	1,745	4,843	7.4	31.9
4	3,292	83	1,321	4,613	7.4	31.9
5	3,481	73	1,166	4,646	8.9	31.9

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.14 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 3

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	501	1
2	333	16
3	321	28
4	551	14
5	517	18

* The savings represent the average LCC for affected consumers.

Table V.15 Average LCC and PBP Results for Equipment Class 4

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	4,144	229	3,654	7,798	-	32.0
1	4,099	213	3,401	7,500	instant	32.0
2	4,131	206	3,281	7,412	instant	32.0
3	4,406	165	2,627	7,033	3.6	32.0
4	4,495	140	2,236	6,730	3.4	32.0
5	4,637	133	2,118	6,755	4.8	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.16 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 4

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	377	6
2	394	9
3	765	9
4	1,068	2
5	1,044	3

* The savings represent the average LCC for affected consumers.

Medium-Voltage Dry-Type Distribution Transformer

Table V.17 Average LCC and PBP Results for Equipment Class 6

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	20,721	1,254	19,963	40,684	-	32.1
1	20,875	1,187	18,902	39,777	0.7	32.1
2	21,260	1,143	18,198	39,458	3.3	32.1
3	23,360	1,025	16,326	39,686	10.6	32.1
4	25,797	905	14,409	40,206	14.8	32.1
5	27,860	797	12,687	40,548	15.0	32.1

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.18 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 6

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	1,597	6
2	1,389	10
3	998	35
4	478	50
5	136	47

* The savings represent the average LCC for affected consumers.

Table V.19 Average LCC and PBP Results for Equipment Class 8

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	66,302	3,709	58,641	124,943	-	32.0
1	63,624	3,531	55,837	119,461	instant	32.0
2	66,927	3,430	54,221	121,149	1.6	32.0
3	74,479	2,975	47,046	121,525	11.0	32.0
4	79,198	2,711	42,863	122,061	12.7	32.0
5	88,116	2,461	38,911	127,027	17.3	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.20 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 4

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	6,420	3
2	3,794	11
3	3,418	29
4	2,882	29
5	-2,084	64

* The savings represent the average LCC for affected consumers.

Table V.21 Average LCC and PBP Results for Equipment Class 10

TSL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	60,987	3,842	60,631	121,618	-	31.9
1	62,207	3,650	57,597	119,804	6.2	31.9
2	67,101	3,545	55,955	123,056	20.1	31.9
3	74,145	3,186	50,261	124,406	19.9	31.9
4	78,857	2,874	45,330	124,187	18.5	31.9
5	85,976	2,655	41,881	127,857	20.9	31.9

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.22 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 10

TSL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	1,823	19
2	-1,438	77
3	-2,788	63
4	-2,569	67
5	-6,239	85

* The savings represent the average LCC for affected consumers.

b. Consumer Subgroup Analysis

In the consumer subgroup analysis, DOE estimated the impact of the considered TSLs on utilities who deploy distribution transformers in vaults or other space constrained areas, and utilities who serve low population densities. For each of these subgroups, DOE compares the average LCC savings and PBP at each efficiency level for the consumer subgroups with similar metrics.

For the utilities serving low-population densities subgroup DOE presents the impacts of small single-phase liquid-immersed (equipment class 1B) against the those determined for the National average. DOEs analysis show that the impacts for utilities serving low populations to be negligible in terms of impacts and increased total installed cost, see Table V.23 and Table V.24.

In most cases, the average LCC savings and PBP for utilities serving low populations at the considered trial standard levels are not substantially different from the average for all consumers. Chapter 11 of the final rule TSD presents the complete LCC and PBP results for the subgroups.

Utilities Serving Low Population Densities

Table V.23 Comparison of LCC Savings and PBP for Utilities Serving Low Population Densities Subgroup and All Utilities; Equipment Class 1B – Small Single-phase (≤100 kVA)

TSL	All Utilities	Serving Low Population Densities
Average LCC Savings (2022$)		
1	36	38
2	48	51
3	48	51
4	317	381
5	-187	-136
Payback Period (years)		
1	6.9	6.7
2	19.5	23.6
3	19.5	23.6
4	7.4	7.7
5	28.1	30.7
Consumers with Net Cost (%)		
1	29.3	30.9
2	28.5	29.5
3	28.5	29.5
4	7.1	6.3
5	59.3	51.5

Table V.24 Delta Cost over Baseline for

TSL	Delta Total Installed Cost over Baseline (%)
1	0.0
2	0.0
3	0.3
4	0.3
5	6.3

Utilities That Deploy Distribution Transformers in Vaults or Other Space Constrained Areas

As noted in section IV.I of this document, for this final rule DOE considered submersible distribution transformers and their associated vault, or space constrained installation costs with individual representative units, 15 and 16. DOE has incorporated increased installation costs as a function of increased volume in these results. However, as discussed in sections IV.1.2 and V.A of this document, there is considerable uncertainty surrounding the volume increase at which vault replacement would become necessary, and were this to occur at a lower volume than assumed and/or were the volume to increase with EL at a higher rate than assumed, this would result in significantly worse average LCC savings. Due to this significant uncertainty, DOE is unable to pinpoint at which EL, if any, this would occur. The consumer results for these equipment are presented in Table V.25 and Table V.26.

Table V.25 Average LCC and PBP Results for Equipment Class 12

EL	Average Costs *2022$*				Simple Payback *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
--	199,939	1,828	37,168	237,107	0.0	32.0
1	201,741	1,796	36,492	238,233	31.9	32.0
2	205,376	1,736	35,376	240,752	33.4	32.0
3	206,646	1,681	34,384	241,031	25.9	32.0
4	202,966	1,526	32,273	235,239	5.7	32.0
5	212,974	1,205	25,118	238,092	11.9	32.0

* The savings represent the average LCC for affected consumers as determined from the Consumer Purchase Decision Model described in IV.F.3 of this document.

Table V.26 Average LCC Savings Relative to the No-New-Standards Case for Equipment Class 12

EL	Life-Cycle Cost Savings	
	Average LCC Savings* *2022$*	Percent of Consumers that Experience Net Cost
1	-1,761	23.2
2	-3,857	38.5
3	-4,039	43.0
4	1,905	22.9
5	-992	31.9

* The savings represent the average LCC for affected consumers.

c. Rebuttable Presumption Payback

As discussed in section IV.F.11, EPCA establishes a rebuttable presumption that an energy conservation standard is economically justified if the increased purchase cost for a product that meets the standard is less than three times the value of the first-year energy savings resulting from the standard. In calculating a rebuttable presumption PBP for each of the considered TSLs, DOE used discrete values and, as required by EPCA, based the energy use calculation on the DOE test procedures for distribution transformers. In contrast, the PBPs presented in section V.B.1.a of this document were calculated using distributions that reflect the range of energy use in the field.

Table V.27 presents the rebuttable-presumption PBPs for the considered TSLs for distribution transformers. While DOE examined the rebuttable-presumption criterion, it considered whether the standard levels considered for this rule are economically justified through a more detailed analysis of the economic impacts of those levels, pursuant to 42 U.S.C. 6295(o)(2)(B)(i), that considers the full range of impacts to the consumer, manufacturer, Nation, and environment. 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 preliminary determination of economic justification.

Table V.27 Rebuttable-Presumption Payback Periods

EC	Trial Standard Level				
	1	2	3	4	5
1A	12.6	6.4	3.8	3.8	5.5
1B	0.0	0.0	0.0	0.0	9.2
2A	6.2	5.3	5.3	10.0	20.3
2B	4.8	8.9	8.9	8.2	11.4
12	N/A	N/A	N/A	N/A	9.2
3	immediate	2.6	5.9	7.3	6.8
4	immediate	immediate	3.9	3.4	3.8
6	immediate	2.6	8.0	9.6	10.5
8	immediate	1.8	45.3	15.4	14.2
10	infinite	14.9	infinite	36.9	23.5

2. Economic Impacts on Manufacturers

DOE performed an MIA to estimate the impact of amended energy conservation standards on manufacturers of distribution transformers. The next section describes the expected impacts on manufacturers at each considered TSL. Chapter 12 of the final rule TSD explains the analysis in further detail.

a. Industry Cash Flow Analysis Results

In this section, DOE provides GRIM results from the analysis, which examines changes in the industry that would result from amended standards. The following tables summarize the estimated financial impacts (represented by changes in INPV) of potential amended energy conservation standards on manufacturers of distribution transformers, as well as the conversion costs that DOE estimates manufacturers of distribution transformers would incur at each TSL. DOE analyzes the potential impacts on INPV separately for each category of distribution transformer manufacturer: liquid-immersed, LVDT, and MVDT.

As discussed in section IV.J.2.d of this document, DOE modeled two scenarios to evaluate a range of cash flow impacts on the distribution transformer industry: (1) the preservation of gross margin scenario and (2) the preservation of operating profit scenario. In the preservation of gross margin scenario, distribution transformer manufacturers are able to maintain the same gross margin percentage, even as the MPCs of distribution transformers increase due to energy conservation standards. In this scenario, the same gross margin percentage of 20 percent [194] is applied across all ELs. In the preservation of operating profit scenario, manufacturers do not earn additional operating profit when compared to the no-standards case scenario. While manufacturers make the necessary upfront investments required to produce compliant equipment, per-unit operating profit does not change in absolute dollars. The preservation of operating profit scenario results in the lower (or more severe) bound to impacts of amended standards on industry.

Each of the modeled scenarios results in a unique set of cash flows and corresponding industry values at each TSL for each category of distribution transformer manufacturer. In the following discussion, the INPV results refer to the difference in industry value between the no-new-standards case and each standards case resulting from the sum of discounted cash flows from 2024 through 2058. To provide perspective on the short-run cash flow impact, DOE includes in the discussion of results a comparison of free cash flow between the no-new-standards case and the standards case at each TSL in the year before amended standards are required.

DOE presents the range in INPV for liquid-immersed distribution transformer manufacturers in Table V.28 and Table V.29; the range in INPV for LVDT distribution transformer manufacturers in Table V.31 and Table V.32; and the range in INPV for MVDT distribution transformer manufacturers in Table V.34 and Table V.35.

Liquid-Immersed Distribution Transformers

Table V.28 Industry Net Present Value for the Liquid-Immersed Distribution Transformer Industry-Preservation of Gross Margin Scenario

	Units	No-New-Standards Case	Trial Standard Level*				
			1	2	3	4	5
INPV	*2022$ millions*	1,792	1,730	1,734	1,681	1,404	1,454
Change in INPV	*2022$ millions*	-	(62)	(58)	(111)	(388)	(338)
	%	-	(3.5)	(3.2)	(6.2)	(21.6)	(18.8)

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

[194] The gross margin percentage of 20 percent is based on a manufacturer markup of 1.25.

Table V.29 Industry Net Present Value for the Liquid-Immersed Distribution Transformer Industry-Preservation of Operating Profit Scenario

	Units	No-New-Standards Case	Trial Standard Level*				
			1	2	3	4	5
INPV	*2022$ millions*	1,792	1,726	1,715	1,647	1,316	1,106
Change in INPV	*2022$ millions*	-	(66)	(77)	(145)	(476)	(686)
	%	-	(3.7)	(4.3)	(8.1)	(26.6)	(38.3)

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Table V.30 Cash Flow Analysis for the Liquid-Immersed Distribution Transformer Industry

	Units	No-New Standards Case	Trial Standard Levels				
			1	2	3	4	5
Free Cash Flow (2028)	*2022$ millions*	121	84	82	48	(125)	(175)
Change in Free Cash Flow (2028)	*2022$ millions*	-	(36)	(38)	(73)	(246)	(295)
	%	-	(30)	(32)	(60)	(204)	(245)
Product Conversion Costs	*2022$ millions*	-	100	101	118	193	194
Capital Conversion Costs	*2022$ millions*	-	2	6	69	395	503
Total Conversion Costs	*2022$ millions*	-	102	107	187	587	697

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

At TSL 5, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$686 million to −$338 million, corresponding to a change in INPV of −38.3 percent to −18.8 percent. At TSL 5, industry free cash flow is estimated to decrease by approximately 245 percent to −$175 million, compared to the no-new-standard case value of $121 million in 2028, the year before the compliance date.

TSL 5 would set the energy conservation standard at EL 5, max-tech, for all liquid-immersed distribution transformers. DOE estimates that less than one percent of shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $194 million in product conversion costs to redesign transformers and approximately $503 million in capital conversion costs as all liquid-immersed distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 5, the shipment weighted average MPC for liquid-immersed distribution transformers significantly increases by 27.0 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $697 million in conversion costs estimated at TSL 5, ultimately results in a significantly negative change in INPV at TSL 5 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 27.0 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $697 million in conversion costs incurred by manufacturers cause a significantly negative change in INPV at TSL 5 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 4, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$476 million to −$388 million, corresponding to a change in INPV of −26.6 percent to −21.6 percent. At TSL 4, industry free cash flow is estimated to decrease by approximately 204 percent to −$125 million, compared to the no-new-standard case value of $121 million in 2028, the year before the compliance date.

TSL 4 would set the energy conservation standard at EL 4 for all liquid-immersed distribution transformer representative units, except for representative units 15 and 16, which are set at baseline. DOE estimates that less than one percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2029. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $193 million in product conversion costs to redesign transformers and approximately $395 million in capital conversion costs as almost all liquid-immersed distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 4, the shipment weighted average MPC for liquid-immersed distribution transformers increases by 6.9 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $587 million in conversion costs estimated at TSL 4, ultimately results in a moderately negative change in INPV at TSL 4 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 6.9 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $587 million in conversion costs incurred by manufacturers cause a moderately negative change in INPV at TSL 4 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 3, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$145 million to −$111 million, corresponding to a change in INPV of −8.1 percent to −6.2 percent. At TSL 3, industry free cash flow is estimated to decrease by approximately 60 percent to $48 million, compared to the no-new-standard case value of $121 million in 2028, the year before the compliance date.

TSL 3 would set the energy conservation standard at EL 4 for the liquid-immersed distribution transformer representative units 1A, 2A, 3, and 4A; at EL 2 for the liquid-immersed distribution transformer representative units 1B, 2B, 4B, 5, and 17; and at baseline for the liquid-immersed distribution transformer representative units 15 and 16. DOE estimates that approximately 3.7 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2029. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $118 million in product conversion costs to redesign transformers and approximately $69 million in capital conversion costs as a portion of liquid-immersed distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 3, the shipment weighted average MPC for liquid-immersed distribution transformers increases by 2.6 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $187 million in conversion costs estimated at TSL 3, ultimately results in a moderately negative change in INPV at TSL 3 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 2.6 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $187 million in conversion costs incurred by manufacturers cause a moderately negative change in INPV at TSL 3 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 2, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$77 million to −$58 million, corresponding to a change in INPV of −4.3 percent to −3.2 percent. At TSL 2, industry free cash flow is estimated to decrease by approximately 32 percent to $82 million, compared to the no-new-standard case value of $121 million in 2028, the year before the compliance date.

TSL 2 would set the energy conservation standard at EL 2 for all liquid-immersed distribution transformer representative units, except for representative units 15 and 16, which are set at baseline. DOE estimates that approximately 4.0 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2029. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $101 million in product conversion costs to redesign transformers and approximately $6 million in capital conversion costs as almost all liquid-immersed distribution transformer cores manufactured are expected to continue to use GOES steel.

At TSL 2, the shipment weighted average MPC for liquid-immersed distribution transformers increases slightly by 1.5 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes a slight increase in manufacturers' free cash flow. However, the $107 million in conversion costs estimated at TSL 2, ultimately results in a slightly negative change in INPV at TSL 2 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 1.5 percent increase in the shipment weighted average MPC results in a slight reduction in the margin after the compliance year. This slight reduction in the manufacturer margin and the $107 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 2 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 1, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$66 million to −$62 million, corresponding to a change in INPV of −3.7 percent to −3.5 percent. At TSL 1, industry free cash flow is estimated to decrease by approximately 30 percent to $84 million, compared to the no-new-standard case value of $121 million in 2028, the year before the compliance date.

TSL 1 would set the energy conservation standard at EL 1 for all liquid-immersed distribution transformer representative units, except for representative units 15 and 16, which are set at baseline. DOE estimates that approximately 13.3 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2029. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $100 million in product conversion costs to redesign transformers and approximately $2 million in capital conversion costs as almost all liquid-immersed distribution transformer cores manufactured are expected to continue to use GOES steel.

At TSL 1, the shipment weighted average MPC for liquid-immersed distribution transformers increases slightly by 0.3 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes a slight increase in manufacturers' free cash flow. However, the $102 million in conversion costs estimated at TSL 1, ultimately results in a slightly negative change in INPV at TSL 1 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 0.3 percent increase in the shipment weighted average MPC results in a slight reduction in the margin after the compliance year. This slight reduction in the manufacturer margin and the $102 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 1 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

Low-Voltage Dry-Type Distribution Transformers

Table V.31 Industry Net Present Value for the Low-Voltage Dry-Type Distribution Transformer Industry-Preservation of Gross Margin Scenario

	Units	No-New-Standards Case	Trial Standard Level*				
			1	2	3	4	5
INPV	*2022$ millions*	212	203	202	193	159	158
Change in INPV	*2022$ millions*	-	(8.9)	(9.6)	(18.9)	(52.2)	(54.0)
	%	-	(4.2)	(4.5)	(8.9)	(24.7)	(25.5)

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Table V.32 Industry Net Present Value for the Low-Voltage Dry-Type Distribution Transformer Industry-Preservation of Operating Profit Scenario

	Units	No-New-Standards Case	Trial Standard Level*				
			1	2	3	4	5
INPV	*2022$ millions*	212	203	201	184	149	143
Change in INPV	*2022$ millions*	-	(8.5)	(10.4)	(27.1)	(62.9)	(68.4)
	%	-	(4.0)	(4.9)	(12.8)	(29.7)	(32.3)

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Table V.33 Cash Flow Analysis for the Low-Voltage Dry-Type Distribution Transformer Industry

	Units	No-New Standards Case	Trial Standard Levels				
			1	2	3	4	5
Free Cash Flow (2028)	*2022$ millions*	20.9	15.4	14.6	6.5	(15.2)	(17.5)
Change in Free Cash Flow (2028)	*2022$ millions*	-	(5.5)	(6.3)	(14.4)	(36.1)	(38.4)
	%	-	(26.4)	(30.1)	(68.8)	(173.0)	(183.6)
Product Conversion Costs	*2022$ millions*	-	15.5	15.9	19.9	30.3	31.0
Capital Conversion Costs	*2022$ millions*	-	0.0	1.4	16.3	56.4	60.8
Total Conversion Costs	*2022$ millions*	-	15.5	17.3	36.1	86.7	91.8

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

At TSL 5, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$68.4 million to −$54.0 million, corresponding to a change in INPV of −32.3 percent to −25.5 percent. At TSL 5, industry free cash flow is estimated to decrease by approximately 183.6 percent to −$17.5 million, compared to the no-new-standard case value of $20.9 million in 2028, the year before the compliance date.

TSL 5 would set the energy conservation standard at EL 5, max-tech, for all LVDT distribution transformers. DOE estimates that no shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates LVDT distribution transformer manufacturers would spend approximately $31.0 million in product conversion costs to redesign transformers and approximately $60.8 million in capital conversion costs as all LVDT distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 5, the shipment weighted average MPC for LVDT distribution transformers increases by 11.1 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $91.8 million in conversion costs estimated at TSL 5, ultimately results in a moderately negative change in INPV at TSL 5 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 11.1 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $91.8 million in conversion costs incurred by manufacturers cause a significantly negative change in INPV at TSL 5 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 4, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$62.9 million to −$52.2 million, corresponding to a change in INPV of −29.7 percent to −24.7 percent. At TSL 4, industry free cash flow is estimated to decrease by approximately 173.0 percent to −$15.2 million, compared to the no-new-standard case value of $20.9 million in 2028, the year before the compliance date.

TSL 4 would set the energy conservation standard at EL 4 for all LVDT distribution transformers. DOE estimates that no shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates LVDT distribution transformer manufacturers would spend approximately $30.3 million in product conversion costs to redesign transformers and approximately $56.4 million in capital conversion costs as almost all LVDT distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 4, the shipment weighted average MPC for LVDT distribution transformers increases by 8.2 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $86.7 million in conversion costs estimated at TSL 4, ultimately results in a moderately negative change in INPV at TSL 4 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 8.2 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $86.7 million in conversion costs incurred by manufacturers cause a moderately negative change in INPV at TSL 4 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 3, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$27.1 million to −$18.9 million, corresponding to a change in INPV of −12.8 percent to −8.9 percent. At TSL 3, industry free cash flow is estimated to decrease by approximately 68.8 percent to $6.5 million, compared to the no-new-standard case value of $20.9 million in 2028, the year before the compliance date.

TSL 3 would set the energy conservation standard at EL 3 for all LVDT distribution transformers. DOE estimates that less than one percent of shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates LVDT distribution transformer manufacturers would spend approximately $19.9 million in product conversion costs to redesign transformers and approximately $16.3 million in capital conversion costs as a portion of LVDT distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 3, the shipment weighted average MPC for LVDT distribution transformers increases by 6.3 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $36.1 million in conversion costs estimated at TSL 3, ultimately results in a moderately negative change in INPV at TSL 3 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 6.3 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $36.1 million in conversion costs incurred by manufacturers cause a moderately negative change in INPV at TSL 3 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 2, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$10.4 million to −$9.6 million, corresponding to a change in INPV of −4.9 percent to −4.5 percent. At TSL 2, industry free cash flow is estimated to decrease by approximately 30.1 percent to $14.6 million, compared to the no-new-standard case value of $20.9 million in 2028, the year before the compliance date.

TSL 2 would set the energy conservation standard at EL 2 for all LVDT distribution transformers. DOE estimates that approximately 3.7 percent of shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates LVDT distribution transformer manufacturers would spend approximately $15.9 million in product conversion costs to redesign transformers and approximately $1.4 million in capital conversion costs as almost all LVDT distribution transformer cores manufactured are expected to continue to use GOES steel.

At TSL 2, the shipment weighted average MPC for LVDT distribution transformers increases by 0.6 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $17.3 million in conversion costs estimated at TSL 2, ultimately results in a slightly negative change in INPV at TSL 2 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 0.6 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $17.3 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 2 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 1, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$8.9 million to −$8.5 million, corresponding to a change in INPV of −4.2 percent to −4.0 percent. At TSL 1, industry free cash flow is estimated to decrease by approximately 26.4 percent to $15.4 million, compared to the no-new-standard case value of $20.9 million in 2028, the year before the compliance date.

TSL 1 would set the energy conservation standard at EL 1 for all LVDT distribution transformers. DOE estimates that approximately 24.5 percent of shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates LVDT distribution transformer manufacturers would spend approximately $15.5 million in product conversion costs to redesign transformers.

At TSL 1, the shipment weighted average MPC for LVDT distribution transformers deceases slightly by 0.3 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In both manufacturer markup scenarios, this slight decrease in manufacturer markup does not have a significant impact on manufacturers' free cash flow. However, in both manufacturer markup scenarios, the $15.5 million in conversion costs estimated at TSL 1, results in a slightly negative change in INPV at TSL 1.

Medium-Voltage Dry-Type Distribution Transformers

Table V.34 Industry Net Present Value for the Medium-Voltage Dry-Type Distribution Transformer Industry-Preservation of Gross Margin Scenario

	Units	No-New-Standards Case	Trial Standard Level*				
			1	2	3	4	5
INPV	*2022$ millions*	95	92	93	76	76	79
Change in INPV	*2022$ millions*	-	(3.5)	(2.3)	(19.1)	(18.6)	(16.3)
	%	-	(3.6)	(2.5)	(20.1)	(19.5)	(17.1)

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Table V.35 Industry Net Present Value for the Medium-Voltage Dry-Type Distribution Transformer Industry-Preservation of Operating Profit Scenario

	Units	No-New-Standards Case	Trial Standard Level*				
			1	2	3	4	5
INPV	*2022$ millions*	95	92	91	69	66	62
Change in INPV	*2022$ millions*	-	(2.7)	(4.4)	(26.4)	(29.5)	(33.2)
	%	-	(2.8)	(4.7)	(27.8)	(31.0)	(34.9)

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Table V.36 Cash Flow Analysis for the Medium-Voltage Dry-Type Distribution Transformer Industry

	Units	No-New Standards Case	Trial Standard Levels				
			1	2	3	4	5
Free Cash Flow (2028)	*2022$ millions*	7.7	5.9	5.6	(6.1)	(7.0)	(7.7)
Change in Free Cash Flow (2028)	*2022$ millions*	-	(1.8)	(2.1)	(13.8)	(14.7)	(15.4)
	%	-	(23.4)	(27.2)	(179.9)	(191.7)	(200.3)
Product Conversion Costs	*2022$ millions*	-	5.0	5.2	9.8	10.1	10.1
Capital Conversion Costs	*2022$ millions*	-	0.0	0.5	22.9	24.7	26.2
Total Conversion Costs	*2022$ millions*	-	5.0	5.7	32.7	34.8	36.2

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

At TSL 5, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$33.2 million to −$16.3 million, corresponding to a change in INPV of −34.9 percent to −17.1 percent. At TSL 5, industry free cash flow is estimated to decrease by approximately 200.3 percent to −$7.7 million, compared to the no-new-standard case value of $7.7 million in 2028, the year before the compliance date.

TSL 5 would set the energy conservation standard at EL 5, max-tech, for all MVDT distribution transformers. DOE estimates that no shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates MVDT distribution transformer manufacturers would spend approximately $10.1 million in product conversion costs to redesign transformers and approximately $26.2 million in capital conversion costs as all MVDT distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 5, the shipment weighted average MPC for LVDT distribution transformers significantly increases by 26.3 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $36.2 million in conversion costs estimated at TSL 5, ultimately results in a moderately negative change in INPV at TSL 5 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 26.3 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $36.2 million in conversion costs incurred by manufacturers cause a significantly negative change in INPV at TSL 5 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 4, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$29.5 million to −$18.6 million, corresponding to a change in INPV of −31.0 percent to −19.5 percent. At TSL 4, industry free cash flow is estimated to decrease by approximately 191.7 percent to −$7.0 million, compared to the no-new-standard case value of $7.7 million in 2028, the year before the compliance date.

TSL 4 would set the energy conservation standard at EL 4 for all MVDT distribution transformers. DOE estimates that no shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates LVDT distribution transformer manufacturers would spend approximately $10.1 million in product conversion costs to redesign transformers and approximately $24.7 million in capital conversion costs as all MVDT distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 4, the shipment weighted average MPC for MVDT distribution transformers increases by 17.0 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $34.8 million in conversion costs estimated at TSL 4, ultimately results in a moderately negative change in INPV at TSL 4 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 17.0 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $34.8 million in conversion costs incurred by manufacturers cause a significantly negative change in INPV at TSL 4 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 3, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$26.4 million to −$19.1 million, corresponding to a change in INPV of −27.8 percent to −20.1 percent. At TSL 3, industry free cash flow is estimated to decrease by approximately 179.9 percent to −$6.1 million, compared to the no-new-standard case value of $7.7 million in 2028, the year before the compliance date.

TSL 3 would set the energy conservation standard at EL 3 for all MVDT distribution transformers. DOE estimates that no shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates MVDT distribution transformer manufacturers would spend approximately $9.8 million in product conversion costs to redesign transformers and approximately $22.9 million in capital conversion costs as the majority of MVDT distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 3, the shipment weighted average MPC for MVDT distribution transformers increases by 11.3 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $32.7 million in conversion costs estimated at TSL 3, ultimately results in a moderately negative change in INPV at TSL 3 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 11.3 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $32.7 million in conversion costs incurred by manufacturers cause a moderately negative change in INPV at TSL 3 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 2, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$4.4 million to −$2.3 million, corresponding to a change in INPV of −4.7 percent to −2.5 percent. At TSL 2, industry free cash flow is estimated to decrease by approximately 27.2 percent to $5.6 million, compared to the no-new-standard case value of $7.7 million in 2028, the year before the compliance date.

TSL 2 would set the energy conservation standard at EL 2 for all MVDT distribution transformers. DOE estimates that approximately 3.8 percent of shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates MVDT distribution transformer manufacturers would spend approximately $5.2 million in product conversion costs to redesign transformers and approximately $0.5 million in capital conversion costs as almost all MVDT distribution transformer cores manufactured are expected to continue to use GOES steel.

At TSL 2, the shipment weighted average MPC for MVDT distribution transformers increases by 3.2 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In the preservation of gross margin scenario, manufacturers can fully pass along this cost increase, which causes an increase in manufacturers' free cash flow. However, the $5.7 million in conversion costs estimated at TSL 2, ultimately results in a slightly negative change in INPV at TSL 2 under the preservation of gross margin scenario.

Under the preservation of operating profit scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or potentially higher MPCs. In this scenario, the 3.2 percent increase in the shipment weighted average MPC results in a reduction in the margin after the compliance year. This reduction in the manufacturer margin and the $5.7 million in conversion costs incurred by manufacturers cause a slightly negative change in INPV at TSL 2 in the preservation of operating profit scenario. This represents the lower-bound, or most severe impact, on manufacturer profitability.

At TSL 1, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$3.5 million to −$2.7 million, corresponding to a change in INPV of −3.6 percent to −2.8 percent. At TSL 1, industry free cash flow is estimated to decrease by approximately 23.4 percent to $5.9 million, compared to the no-new-standard case value of $7.7 million in 2028, the year before the compliance date.

TSL 1 would set the energy conservation standard at EL 1 for all MVDT distribution transformers. DOE estimates that approximately 21.7 percent of shipments would meet these energy conservation standards in the no-new-standards case in 2029. DOE estimates MVDT distribution transformer manufacturers would spend approximately $5.0 million in product conversion costs to redesign transformers.

At TSL 1, the shipment weighted average MPC for MVDT distribution transformers deceases slightly by 1.2 percent relative to the no-new-standards case shipment weighted average MPC in 2029. In both manufacturer markup scenarios, this slight decrease in manufacturer markup does not have a significant impact on manufacturers' free cash flow. However, in both manufacturer markup scenarios, the $5.0 million in conversion costs estimated at TSL 1, results in a slightly negative change in INPV at TSL 1.

b. Direct Impacts on Employment

To quantitatively assess the potential impacts of amended energy conservation standards on direct employment in the distribution transformer industry, DOE used the GRIM to estimate the domestic labor expenditures and number of direct employees in the no-new-standards case and in each of the standards cases during the analysis period.

Production employees are those who are directly involved in fabricating and assembling equipment within a manufacturer facility. Workers performing services that are closely associated with production operations, such as materials handling tasks using forklifts, are included as production labor, as well as line supervisors.

DOE used the GRIM to calculate the number of production employees from labor expenditures. DOE used statistical data from the U.S. Census Bureau's 2021 Annual Survey of Manufacturers (ASM) and the results of the engineering analysis to calculate industry-wide labor expenditures. Labor expenditures related to equipment manufacturing depend on the labor intensity of the product, the sales volume, and an assumption that wages remain fixed in real terms over time. The total labor expenditures in the GRIM were then converted to domestic production employment levels by dividing production labor expenditures by the annual payment per production worker.

Non-production employees account for those workers that are not directly engaged in the manufacturing of the covered equipment. This could include sales, human resources, engineering, and management. DOE estimated non-production employment levels by multiplying the number of distribution transformer workers by a scaling factor. The scaling factor is calculated by taking the ratio of the total number of employees, and the total production workers associated with the industry NAICS code 335311, which covers power, distribution, and specialty transformer manufacturing.

Using data from manufacturer interviews and estimated market share data, DOE estimates that approximately 85 percent of all liquid-immersed distribution transformer manufacturing; 15 percent of all LVDT distribution transformer manufacturing; and 75 percent of all MVDT distribution transformer manufacturing takes place domestically.

Several interested parties commented on the direct employment analysis in the January 2023 NOPR. Some interested parties commented that the standards proposed in the January 2023 NOPR would result in a decrease in domestic employment. UAW commented that it expects mass layoffs as a result of the standards proposed in the January 2023 NOPR since 70 percent of the electrical steel that UAW members produce for Cleveland Cliffs is used in distribution transformer cores. (UAW, No. 90 at P. 2) UAW also commented that currently 90 percent of distribution transformers are made with GOES. Without this demand for GOES, the continued production of all GOES in the United States could be placed in jeopardy. (*Id.*) UAW urged DOE to consider the potential loss of electrical steel jobs as a result of any adopted standards for distribution transformers. (*Id.*) Similarly, UAW Locals commented that the standards proposed in the January 2023 NOPR would make Cleveland Cliffs electrical steel plants uneconomic, which could jeopardize nearly 1,500 steel manufacturing jobs. (UAW Locals, No. 91 at p. 1)

NAHB commented that DOE must consider the possibility that requiring a new manufacturing process to make distribution transformers more efficient may actually require fewer workers. (NAHB, No. 106 at pp. 11–12) Prolec GE commented that any standards that required a shift from GOES production to amorphous steel production would affect domestic employment as currently most of the core manufacturing using GOES is done in-house, and it would need to be shifted to outsourced finished amorphous metal cores where most of the production capacity is not domestic. (Prolec GE, No. 120 at p. 13) Lastly, Cliffs commented that DOE underestimated the required number amount of labor to convert to amorphous production in the January 2023 NOPR and the actual additional number of employees to meet the standards proposed in the January 2023 NOPR will lead to increased offshoring. (Cliffs, No. 105 at pp. 14–15)

Other interested parties comments that the standards proposed in the January 2023 NOPR would result in an increase in domestic employment. Eaton commented that it expects an increase in labor content to meet the standards proposed in the January 2023 NOPR. (Eaton, No. 137 at p. 29) Howard commented that they would need to add 1,000–2,000 employees (which corresponds to a 25–50 percent increase in their current employment levels) to meet the standards proposed in the January 2023 NOPR. (Howard, No. 116 at p. 2) Howard stated they estimate the entire industry could need an additional 5,500 to 6,000 employees to meet the standards proposed in the January 2023 NOPR. (Howard, No. 116 at p. 2) Additionally, Howard commented that in addition to distribution transformer manufacturers adding employees, electrical steel manufacturers would have to add employees as well, which will be difficult given the 3-year compliance period used in the January 2023 NOPR and the current labor market, which lacks available personnel. (Howard, No. 116 at pp. 2–3) Metglas commented that it estimated that amorphous production would require 600 to 900 new U.S. jobs to meet the standards proposed in the January

2023 NOPR. (Metglas, No. 125 at p. 7) Efficiency advocates commented that the expansion of amorphous production capacity would be expected to add hundreds of electrical steel manufacturing jobs. (Efficiency advocates, No. 121 at pp. 4–5) Efficiency advocates additionally stated that producers of GOES would be well positioned to transition production capacity to NOES to preserve manufacturing jobs. (*Id.*)

DOE's direct employment analysis conducted in the January 2023 NOPR presented a range of impacts to employment. As some interested parties commented, manufacturing distribution transformers with amorphous cores will likely require additional employees. However, DOE also recognizes that currently many amorphous core manufacturing locations are outside the U.S., as some interested parties commented. DOE continues to present a range of domestic employment impacts in this final rule that show the likely range in domestic employment given that manufacturing more efficient distribution transformers will likely result in an increase in production employees; however, some manufacturers may shift current domestic production to non-domestic locations to fulfill this additional labor demand. The range of potential impacts displayed in Table V.37, Table V.38, and Table V.39 present the most likely range of potential impacts to domestic employment for the analyzed TSLs.

Liquid-Immersed Distribution Transformers

Table V.37 Domestic Employment for Liquid-Immersed Distribution Transformers in 2029

	No-New Standards Case	Trial Standard Levels*				
		1	2	3	4	5
Domestic Production Workers in 2029	6,561	6,582	6,660	6,731	7,012	8,334
Domestic Non-Production Workers in 2029	2,721	2,730	2,762	2,791	2,908	3,456
Total Domestic Employment in 2029	9,282	9,312	9,422	9,522	9,920	11,790
Potential Changes in Total Domestic Employment in 2029	-	(67) - 30	(86) - 140	(229) - 240	(2,102) - 638	(2,500) - 2,508

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Using the estimated labor content from the GRIM combined with data from the 2021 ASM, DOE estimates that there would be approximately 6,561 domestic production workers, and 2,721 domestic non-production workers involved in liquid-immersed distribution transformer manufacturing in 2029 in the absence of amended energy conservation standards. Table V.37 shows the range of the impacts of energy conservation standards on U.S. production on liquid-immersed distribution transformers.

Amorphous core production is more labor intensive and would require additional labor expenditures. The upper range of the ''Potential Change in Total Domestic Employment in 2029'' displayed in Table V.37, assumes that all domestic liquid-immersed distribution transformer manufacturing remains in the U.S. For this scenario, the additional labor expenditures associated with amorphous core production result in the number of total direct employees to increase due to energy conservation standards. At higher TSLs, the estimated number of amorphous cores used in liquid-immersed distribution transformers increases, which causes the number of direct employees to also increase. The lower range of the ''Potential Change in Total Domestic Employment in 2029'' displayed in Table V.37, assumes that as more amorphous cores are used to meet higher energy conservation standards, either the amorphous core production is outsourced to core only manufacturers (manufacturers that specialize in manufacturing cores used in distribution transformers, but do not actually manufacture entire distribution transformers) which may be located in foreign countries, or distribution transformer manufacturing is re-located to foreign countries. This lower range assumes that 30 percent of distribution transformers using amorphous cores are re-located to foreign countries due to energy conservation standards. DOE acknowledges that each distribution transformer manufacturer would individually make a business decision to either make the substantial investments to add or increase their own amorphous core production capabilities and continue to manufacturer their own cores in-house; outsource their amorphous core production to another distribution core manufacturer, which may or may not be located in the U.S.; or re-locate some or all of their distribution transformer manufacturing to a foreign country. DOE acknowledges there is a wide range of potential domestic employment impacts due to energy conservation standards, especially at the higher TSLs. The ranges in potential employment impacts displayed in Table V.37 at each TSL attempt to provide a reasonable upper and lower bound to how liquid-immersed distribution transformer manufacturers may respond to potential energy conservation standards.

Low-Voltage Dry-Type Distribution Transformers

Table V.38 Domestic Employment for Low-Voltage Dry-Type Distribution Transformers in 2029

	No-New Standards Case	Trial Standard Levels*				
		1	2	3	4	5
Domestic Production Workers in 2029	185	184	186	197	200	206
Domestic Non-Production Workers in 2029	77	76	77	82	83	85
Total Domestic Employment in 2029	262	260	263	279	283	291
Potential Changes in Total Domestic Employment in 2029	-	(2) - 0	(2) - 1	(17) - 17	(56) - 21	(62) - 29

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Using the estimated labor content from the GRIM combined with data from the 2021 ASM, DOE estimates that there would be approximately 185 domestic production workers, and 77 domestic non-production workers involved in LVDT distribution transformer manufacturing in 2029 in the absence of amended energy conservation standards. Table V.38 shows the range of the impacts of energy conservation standards on U.S. production on LVDT distribution transformers.

DOE used the same methodology to estimate the potential impacts to domestic employment for LVDT distribution transformer manufacturing that was used for liquid-immersed distribution transformer manufacturing. The upper range of the ''Potential Change in Total Domestic Employment in 2029'' displayed in Table V.38, assumes that all LVDT distribution transformer manufacturing remains in the U.S. The lower range of the ''Potential Change in Total Domestic Employment in 2029'', assumes that 30 percent of distribution transformers using amorphous cores are re-located to foreign countries, either due to amorphous core production that is outsourced to core only manufacturers located in foreign countries or LVDT distribution transformer manufacturers re-locating their distribution transformer production to foreign countries.

Medium-Voltage Dry-Type Distribution Transformers

Table V.39 Domestic Employment for Medium-Voltage Dry-Type Distribution Transformers in 2029

	No-New Standards Case	Trial Standard Levels*				
		1	2	3	4	5
Domestic Production Workers in 2029	300	296	310	334	351	379
Domestic Non-Production Workers in 2029	125	123	129	139	146	157
Total Domestic Employment in 2029	425	419	439	473	497	536
Potential Changes in Total Domestic Employment in 2029	-	(6) - 0	(11) - 14	(76) - 48	(105) - 72	(114) - 111

* Numbers in parentheses "()" are negative. Some numbers might not round due to rounding.

Using the estimated labor content from the GRIM combined with data from the 2021 ASM, DOE estimates that there would be approximately 300 domestic production workers, and 125 domestic non-production workers involved in MVDT distribution transformer manufacturing in 2029 in the absence of amended energy conservation standards. Table V.39 shows the range of the impacts of energy conservation standards on U.S. production on MVDT distribution transformers.

DOE used the same methodology to estimate the potential impacts to domestic employment for MVDT distribution transformer manufacturing that was used for liquid-immersed distribution transformer manufacturing. The upper range of the ''Potential Change in Total Domestic Employment in 2029'' displayed in Table V.39, assumes that all MVDT distribution transformer manufacturing remains in the U.S. The lower range of the ''Potential Change in Total Domestic Employment in 2029'', assumes that 30 percent of distribution transformers using amorphous cores are re-located to foreign countries, either due to amorphous core production that is outsourced to core only manufacturers located in foreign countries or MVDT distribution transformer manufacturers re-locating their distribution transformer production to foreign countries.

c. Impacts on Manufacturing Capacity

The prices of raw materials currently used in distribution transformers, such as GOES, copper, and aluminum, have all experienced a significant increase in price starting at the beginning of 2021. The availability of these commodities remains a significant concern with distribution transformer manufacturers. As previously stated in the January 2023

NOPR, GOES investment from steel producers is competing with NOES investment suited for electric vehicle production. This competing investment, combined with demand growth supporting other electrification trends has led to a substantial global increase in GOES. However, amorphous alloys have not seen the same significant increase in price as GOES.

The availability of amorphous material is a concern for many distribution transformer manufacturers. Based on information received during manufacturer interviews, some distribution transformer manufacturers suggested that there would not be enough amorphous steel available to be used in all or even most distribution transformers currently sold in the U.S. Other distribution transformer manufacturers and steel suppliers interviewed stated that, while the current capacity of amorphous steel does not exist to supply the majority of the steel used in distribution transformer cores, steel manufacturers are capable of significantly increasing their amorphous steel production if there is sufficient market demand for amorphous steel.

Cliffs commented that the January 2023 NOPR did not accurately account for the supply chain constraints associated with ramping up production of amorphous steel in addition to the tremendous increased demands linked to greater market penetration of electric vehicles and other decarbonization efforts that the steel industry is facing. (Cliffs., No, 105 at p. 15) Cliffs continued stating the increased costs associated with all distribution transformers using amorphous cores, which currently constitutes about three percent of the market for distribution transformers, will be massive and stretch the limits of existing supply chains beyond their breaking point. (*Id.*) Eaton commented that changing the current supply of GOES that used in almost all distribution transformer cores today to having almost all distribution transformers using amorphous cores would disrupt the supply of cores and/or core steel to a massive extent and would likely to be accompanied by some unexpected outcomes. (Eaton, No. 137 at p. 26)

While the availability of both GOES and amorphous steel is a concern for many distribution transformer manufacturers, steel suppliers should be able to meet the market demand for amorphous steel for all TSLs analyzed given the 5-year compliance period for distribution transformers. Steel manufacturers should be able to significantly increase their supply of amorphous steel if they know there will be an increase in the demand for this material due to energy conservation standards for distribution transformers. See section V.C for a more detailed discussion of the expected core materials needed to meet amended standards.

Additionally, in response to the January 2023 NOPR, Howard commented that the standards proposed in the January 2023 NOPR would require them to redesign 8,000—10,000 distribution transformers, which ordinarily would be done over a 5-year period. (Howard, No. 116 at p. 3) Howard also commented that they estimate that facility and equipment additions alone will take 5 years and Howard will need to begin production of new units prior to the actual compliance deadline to ensure all raw materials are used. (*Id.*) In the January 2023 NOPR, DOE used a 3-year compliance period. For this final rule, DOE is adopting a 5-year compliance period. While DOE acknowledges that manufacturers will be required to make significant changes to their manufacturing facilities to be able to produce distribution transformers that use amorphous cores, this is not anticipated to cause manufacturing capacity constraints given the 5-year compliance period. Further, DOE notes that the adopted standards in this final rule require substantially less manufacturer investment than those proposed in the January 2023 NOPR.

d. Impacts on Subgroups of Manufacturers

As discussed in section IV.J.1 of this document, using average cost assumptions to develop an industry cash flow estimate may not be adequate for assessing differential impacts among manufacturer subgroups. Small manufacturers, niche manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. DOE used the results of the industry characterization to group manufacturers exhibiting similar characteristics. Consequently, DOE considered four manufacturer subgroups in the MIA: liquid-immersed, LVDT, MVDT, and small manufacturers as a subgroup for a separate impact analysis. DOE discussed the potential impacts on liquid-immersed, LVDT, and MVDT distribution transformer manufacturers separately in sections V.B.2.a and V.B.2.b of this document.

For the small business subgroup analysis, DOE applied the small business size standards published by the Small Business Administration (SBA) to determine whether a company is considered a small business. The size standards are codified at 13 CFR part 121. To be categorized as a small business under NAICS code 335311, ''power, distribution, and specialty transformer manufacturing,'' a distribution transformer manufacturer and its affiliates may employ a maximum of 800 employees. The 800-employee threshold includes all employees in a business's parent company and any other subsidiaries. For a discussion of the impacts on the small manufacturer subgroup, see the Regulatory Flexibility Analysis in section VI.B of this document.

e. Cumulative Regulatory Burden

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

DOE evaluates product-specific regulations that will take effect approximately 3 years before or after the estimated 2029 compliance date of any amended energy conservation standards for distribution transformers. This information is presented in Table V.40.

Table V.40 Compliance Dates and Expected Conversion Expenses of Federal Energy Conservation Standards Affecting Distribution Transformer Manufacturers

Federal Energy Conservation Standard	Number of Mfgs*	Number of Manufacturers Affected from this Rule**	Approx. Standards Year	Industry Conversion Costs (*millions*)	Industry Conversion Costs / Product Revenue***
Dedicated-Purpose Pool Pump Motors 87 FR 37122 (Jun. 21, 2022)	5	1	2026 & 2028	$46.2 (*2020$*)	2.8%
Electric Motors 88 FR 36066 (Jun. 1, 2023)	74	2	2027	$468.5 (*2021$*)	2.6%
External Power Supplies† 88 FR 7284 (Feb. 2, 2023)	658	3	2027	$17.4 (*2022$*)	0.3%
General Service Lamps† 88 FR 1638 (Jan. 11, 2023)	100+	1	2028	$407.1 (*2021$*)	4.5%

* This column presents the total number of manufacturers identified in the energy conservation standard rule contributing to cumulative regulatory burden.
** This column presents the number of manufacturers producing distribution transformers that are also listed as manufacturers in the listed energy conservation standard contributing to cumulative regulatory burden.
*** This column presents industry conversion costs as a percentage of product revenue during the conversion period. Industry conversion costs are the upfront investments manufacturers must make to sell compliant products/equipment. The revenue used for this calculation is the revenue from just the covered product/equipment associated with each row. The conversion period is the time frame over which conversion costs are made and lasts from the publication year of the final rule to the compliance year of the energy conservation standard. The conversion period typically ranges from 3 to 5 years, depending on the rulemaking.
† Indicates a NOPR publication. Values may change on publication of a final rule.

3. National Impact Analysis

This section presents DOE's estimates of the national energy savings and the NPV of consumer benefits that would result from each of the TSLs considered as potential amended standards.

a. National Energy Savings

To estimate the energy savings attributable to potential amended standards for distribution transformers, DOE compared their energy consumption under the no-new-standards case to their anticipated energy consumption under each TSL. The savings are measured over the entire lifetime of products purchased in the 30-year period that begins in the year of anticipated compliance with amended standards 2029–2058. Table V.41 presents DOE's projections of the national energy savings for each TSL considered for distribution transformers, the results showing DOE's amended standards are in bold. The savings were calculated using the approach described in section IV.H of this document.

Table V.41 Cumulative National Energy Savings for Distribution Transformer; 30 Years of Shipments (2029–2058)

	Standard Level				
	1	**2**	**3**	**4**	**5**
Primary Energy Savings (Quads)					
Liquid-Immersed					
Equipment Class 1A	0.03	0.05	**0.78**	0.78	0.80
Equipment Class 1B	0.20	0.42	**0.42**	5.59	5.59
Equipment Class 2A	0.03	0.10	**0.92**	0.92	0.93
Equipment Class 2B	0.16	0.53	**0.53**	3.09	3.19
Equipment Class 12	0.00	0.00	**0.00**	0.00	0.11
Liquid-Immersed Total	0.43	1.11	**2.66**	10.39	10.63
Low-Voltage Dry-Type					
Equipment Class 3	0.02	0.03	**0.06**	0.11	0.12
Equipment Class 4	0.37	0.54	**1.60**	2.21	2.34
Low-Voltage Dry-Type Total	0.40	0.59	**1.71**	2.38	2.53
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.01	**0.02**	0.03	0.04	0.04
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.05	**0.07**	0.23	0.30	0.36
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.04	**0.05**	0.14	0.19	0.22
Medium-Voltage Dry-Type Total	0.10	**0.14**	0.41	0.53	0.63
FFC Energy Savings (Quads)					
Liquid-Immersed					
Equipment Class 1A	0.03	0.06	**0.81**	0.81	0.82
Equipment Class 1B	0.21	0.43	**0.43**	5.74	5.74
Equipment Class 2A	0.03	0.10	**0.95**	0.95	0.96
Equipment Class 2B	0.17	0.55	**0.55**	3.18	3.28
Equipment Class 12	0.00	0.00	**0.00**	0.00	0.11
Liquid-Immersed Total	0.45	1.14	**2.73**	10.67	10.91
Low-Voltage Dry-Type					
Equipment Class 3	0.02	0.04	**0.06**	0.11	0.13
Equipment Class 4	0.38	0.56	**1.65**	2.27	2.40
Low-Voltage Dry-Type Total	0.40	0.59	**1.71**	2.38	2.53
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.01	**0.02**	0.03	0.04	0.05
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00

Equipment Class 8	0.05	**0.07**	0.24	0.31	0.37
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.04	**0.05**	0.15	0.20	0.23
Medium-Voltage Dry-Type Total	0.10	**0.14**	0.42	0.55	0.65

OMB Circular A–4 [195] requires agencies to present analytical results, including separate schedules of the monetized benefits and costs that show the type and timing of benefits and costs. Circular A–4 also directs agencies to consider the variability of key elements underlying the estimates of benefits and costs. For this rulemaking, DOE undertook a sensitivity analysis using 9 years, rather than 30 years, of product shipments. The choice of a 9-year period is a proxy for the timeline in EPCA for the review of certain energy conservation standards and potential revision of and compliance with such revised standards.[196] The review timeframe established in EPCA is generally not synchronized with the product lifetime, product manufacturing cycles, or other factors specific to distribution transformers. Thus, such results are presented for informational purposes only and are not indicative of any change in DOE's analytical methodology. The NES sensitivity analysis results based on a 9-year analytical period are presented in Table V.42. The impacts are counted over the lifetime of distribution transformers purchased during the period 2029–2058, the results showing DOE's amended standards are in bold.

[195] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* Available at *www.whitehouse.gov/omb/information-for-agencies/circulars* (last accessed January 19, 2024). DOE used the prior version of Circular A–4 (September 17, 2003) in accordance with the effective date of the November 9, 2023 version.

[196] 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. (42 U.S.C. 6316(a); 42 U.S.C. 6295(m)) 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.

Table V.42 Cumulative National Energy Savings for Distribution Transformers; 9 Years of Shipments (2029–2058)

	Standard Level				
	1	2	3	4	5
Primary Energy Savings (Quads)					
Liquid-Immersed					
Equipment Class 1A	0.01	0.02	**0.23**	0.23	0.23
Equipment Class 1B	0.06	0.12	**0.12**	1.61	1.61
Equipment Class 2A	0.01	0.03	**0.27**	0.27	0.27
Equipment Class 2B	0.05	0.15	**0.15**	0.89	0.92
Equipment Class 12	0.00	0.00	**0.00**	0.00	0.03
Liquid-Immersed Total	0.13	0.32	**0.77**	3.00	3.07
Low-Voltage Dry-Type					
Equipment Class 3	0.00	0.01	**0.02**	0.03	0.04
Equipment Class 4	0.11	0.15	**0.46**	0.63	0.67
Low-Voltage Dry-Type Total	0.11	0.16	**0.48**	0.66	0.70
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.00	**0.00**	0.01	0.01	0.01
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.01	**0.02**	0.07	0.09	0.10
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.01	**0.01**	0.04	0.05	0.06
Medium-Voltage Dry-Type Total	0.03	**0.04**	0.12	0.15	0.18
FFC Energy Savings (Quads)					
Liquid-Immersed					
Equipment Class 1A	0.01	0.02	**0.23**	0.23	0.24
Equipment Class 1B	0.06	0.13	**0.13**	1.66	1.66
Equipment Class 2A	0.01	0.03	**0.27**	0.27	0.28
Equipment Class 2B	0.05	0.16	**0.16**	0.92	0.95
Equipment Class 12	0.00	0.00	**0.00**	0.00	0.03
Liquid-Immersed Total	0.13	0.33	**0.79**	3.08	3.15
Low-Voltage Dry-Type					
Equipment Class 3	0.00	0.01	**0.02**	0.03	0.04
Equipment Class 4	0.11	0.16	**0.47**	0.65	0.69
Low-Voltage Dry-Type Total	0.11	0.17	**0.49**	0.68	0.72
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.00	**0.00**	0.01	0.01	0.01
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00

Equipment Class 8	0.01	**0.02**	0.07	0.09	0.10
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.01	**0.02**	0.04	0.06	0.07
Medium-Voltage Dry-Type Total	0.03	**0.04**	0.12	0.16	0.19

b. Net Present Value of Consumer Costs and Benefits

DOE estimated the cumulative NPV of the total costs and savings for consumers that would result from the TSLs considered for distribution transformers. In accordance with OMB's guidelines on regulatory analysis,[197] DOE calculated NPV using both a 7-percent and a 3-percent real discount rate. Table V.43 shows the consumer NPV results with impacts counted over the lifetime of products purchased during the period 2029–2058.

Table V.43 Cumulative Net Present Value of Consumer Benefits for Distribution Transformers; 30 Years of Shipments (2029–2058)

	Standard Level				
	1	**2**	**3**	**4**	**5**
3 percent Discount Rate					
Liquid-Immersed					
Equipment Class 1A	0.12	0.16	**0.70**	0.70	-2.65
Equipment Class 1B	0.89	1.21	**1.21**	7.64	-1.92
Equipment Class 2A	0.05	0.07	**1.07**	1.07	0.66
Equipment Class 2B	0.32	0.43	**0.43**	3.60	0.28
Equipment Class 12	0.00	0.00	**0.00**	0.00	0.04
Liquid-Immersed Total	1.38	1.87	**3.41**	13.01	-3.57
Low-Voltage Dry-Type					
Equipment Class 3	0.06	0.12	**0.20**	0.51	0.50
Equipment Class 4	1.39	1.92	**6.48**	9.64	9.36
Low-Voltage Dry-Type Total	1.45	2.04	**6.68**	10.14	9.86
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.01
Equipment Class 6	0.04	**0.04**	0.07	0.07	0.07
Equipment Class 7	0.00	**0.00**	0.01	0.01	0.01
Equipment Class 8	0.22	**0.17**	0.67	0.65	0.37

[197] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A4/a-4.pdf#page=33.*

Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.10	**0.00**	0.39	0.41	0.26
Medium-Voltage Dry-Type Total	0.35	**0.22**	1.15	1.14	0.72
7 percent Discount Rate					
Liquid-Immersed					
Equipment Class 1A	0.04	0.05	**0.06**	0.06	-1.83
Equipment Class 1B	0.29	0.37	**0.37**	1.86	-3.96
Equipment Class 2A	0.01	-0.01	**0.18**	0.18	-0.09
Equipment Class 2B	0.06	-0.05	**-0.05**	0.72	-1.48
Equipment Class 12	0.00	0.00	0.00	0.00	-0.03
Liquid-Immersed Total	0.41	0.36	**0.56**	2.82	-7.39
Low-Voltage Dry-Type					
Equipment Class 3	0.02	0.04	0.05	0.15	0.13
Equipment Class 4	0.50	0.67	2.03	3.05	2.87
Low-Voltage Dry-Type Total	0.52	0.71	**2.08**	3.20	3.00
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	0.00	0.00	0.00	0.00
Equipment Class 6	0.01	0.01	0.02	0.01	0.00
Equipment Class 7	0.00	0.00	0.00	0.00	0.00
Equipment Class 8	0.09	0.05	0.16	0.12	-0.05
Equipment Class 9	0.00	0.00	0.00	0.00	0.00
Equipment Class 10	0.03	-0.03	0.07	0.05	-0.03
Medium-Voltage Dry-Type Total	0.13	**0.03**	0.25	0.18	-0.08

The NPV results based on the aforementioned 9-year analytical period are presented in Table V.44. The impacts are counted over the lifetime of products purchased during the period 2029–2037. As mentioned previously, such results are presented for informational purposes only and are not indicative of any change in DOE's analytical methodology or decision criteria.

Table V.44 Cumulative Net Present Value of Consumer Benefits for Distribution Transformers; 9 Years of Shipments (2029–2037)

	Standard Level				
	1	**2**	**3**	**4**	**5**
3 percent Discount Rate					
Liquid-Immersed					
Equipment Class 1A	0.05	0.06	**0.27**	0.27	-1.02
Equipment Class 1B	0.34	0.47	**0.47**	2.95	-0.73
Equipment Class 2A	0.02	0.03	**0.41**	0.41	0.26
Equipment Class 2B	0.12	0.17	**0.17**	1.39	0.11
Equipment Class 12	0.00	0.00	**0.00**	0.00	0.02
Liquid-Immersed Total	0.53	0.72	**1.32**	5.03	-1.36
Low-Voltage Dry-Type					
Equipment Class 3	0.02	0.04	**0.08**	0.19	0.19
Equipment Class 4	0.53	0.74	**2.49**	3.70	3.60
Low-Voltage Dry-Type Total	0.56	0.78	**2.56**	3.89	3.79
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.01	**0.01**	0.03	0.03	0.03
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.08	**0.07**	0.26	0.25	0.14
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.04	**0.00**	0.15	0.16	0.10
Medium-Voltage Dry-Type Total	0.14	**0.08**	0.44	0.44	0.28
7 percent Discount Rate					
Liquid-Immersed					
Equipment Class 1A	0.02	0.03	**0.03**	0.03	-0.94
Equipment Class 1B	0.15	0.19	**0.19**	0.96	-2.04
Equipment Class 2A	0.00	0.00	**0.09**	0.09	-0.04
Equipment Class 2B	0.03	-0.02	**-0.02**	0.37	-0.76
Equipment Class 12	0.00	0.00	**0.00**	0.00	-0.01
Liquid-Immersed Total	0.21	0.19	**0.29**	1.45	-3.81
Low-Voltage Dry-Type					
Equipment Class 3	0.01	0.02	**0.03**	0.08	0.07
Equipment Class 4	0.26	0.34	**1.04**	1.56	1.47
Low-Voltage Dry-Type Total	0.27	0.36	**1.07**	1.64	1.54
Medium-Voltage Dry-Type					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.01	**0.01**	0.01	0.01	0.00
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.05	**0.03**	0.08	0.06	-0.03
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.01	**-0.02**	0.04	0.03	-0.02
Medium-Voltage Dry-Type Total	0.07	**0.02**	0.13	0.09	-0.04

The previous results reflect the use of a default trend to estimate the change in price for distribution transformers over the analysis period (*see* section IV.H.3 of this document). DOE also conducted a sensitivity analysis that considered one scenario with a lower rate of price decline than the reference case and one scenario with a higher rate of price decline than the reference case. The results of these alternative cases are presented in appendix 10C of the final rule TSD. In the high-price-decline case, the NPV of consumer benefits is higher than in the default case. In the low-price-decline case, the NPV of consumer benefits is lower than in the default case.

c. Indirect Impacts on Employment

DOE estimates that amended energy conservation standards for distribution transformers will reduce energy expenditures for consumers of those products, with the resulting net savings being redirected to other forms of economic activity. These expected shifts in spending and economic activity could affect the demand for labor. As described in section IV.N of this document, DOE used an input/output model of the U.S. economy to estimate indirect employment impacts of the TSLs that DOE considered. There are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Therefore, DOE generated results for near-term timeframes (2029–2034), where these uncertainties are reduced.

The results suggest that the adopted standards are likely to have a 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 16 of the final rule TSD presents detailed results regarding anticipated indirect employment impacts.

4. Impact on Utility or Performance of Products

As discussed in section IV.C.1.b of this document, DOE has concluded that the standards adopted in this final rule will not lessen the utility or performance of the distribution transformers under consideration in this rulemaking. Manufacturers of these products currently offer units that meet or exceed the adopted standards.

5. Impact of Any Lessening of Competition

DOE considered any lessening of competition that would be likely to result from new or amended standards. As discussed in section III.F.1.e of this document, EPCA 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 in writing to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. To assist the Attorney General in making this determination, DOE provided the Department of Justice (DOJ) with copies of the NOPR and the TSD for review. In its assessment letter responding to DOE, DOJ concluded that the proposed energy conservation standards for distribution transformers are unlikely to have a significant adverse impact on competition. DOE is publishing the Attorney General's assessment at the end of this 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 (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. Chapter 15 in the final rule TSD presents the estimated impacts on electricity generating capacity, relative to the no-new-standards case, for the TSLs that DOE considered in this rulemaking.

Energy conservation resulting from potential energy conservation standards for distribution transformers is expected to yield environmental benefits in the form of reduced emissions of certain air pollutants and greenhouse gases. Table V.45 through Table V.48 provides DOE's estimate of cumulative emissions reductions expected to result from the TSLs considered in this rulemaking. The emissions were calculated using the multipliers discussed in section IV.K of this document. DOE reports annual emissions reductions for each TSL in chapter 13 of the final rule TSD.

Table V.45 Cumulative Emissions Reduction for all Distribution Transformers Shipped During the Period 2029–2058

	Trial Standard Level				
	1	**2**	**3**	**4**	**5**
Electric Power Sector Emissions					
CO_2 (*million metric tons*)	15.87	31.68	82.18	232.02	239.52
CH_4 (*thousand tons*)	0.95	1.88	4.89	13.78	14.23
N_2O (*thousand tons*)	0.12	0.26	0.67	1.86	1.93
SO_2 (*thousand tons*)	4.09	8.15	21.13	59.56	61.54
NO_X (*thousand tons*)	6.46	12.89	33.43	94.16	97.23
Hg (*tons*)	0.02	0.05	0.14	0.41	0.42
Upstream Emissions					
CO_2 (*million metric tons*)	1.57	3.11	8.05	22.54	23.35
CH_4 (*thousand tons*)	143.01	283.53	734.7	2055.39	2129.46
N_2O (*thousand tons*)	0	0.01	0.03	0.1	0.1
SO_2 (*thousand tons*)	0.09	0.18	0.46	1.28	1.33
NO_X (*thousand tons*)	24.52	48.6	125.96	352.37	365.08
Hg (*tons*)	1.57	3.11	8.05	22.54	23.35
Total FFC Emissions					
CO_2 (*million metric tons*)	17.44	34.78	90.23	254.56	262.88
CH_4 (*thousand tons*)	143.96	285.41	739.59	2069.16	2143.69
N_2O (*thousand tons*)	0.13	0.26	0.7	1.97	2.03
SO_2 (*thousand tons*)	4.18	8.33	21.6	60.85	62.87
NO_X (*thousand tons*)	30.98	61.49	159.39	446.55	462.32
Hg (*tons*)	0.02	0.05	0.14	0.41	0.42

Table V.46 Cumulative Emissions Reduction for Liquid-immersed Distribution Transformers Shipped During the Period 2029–2058

	Trial Standard Level				
	1	**2**	**3**	**4**	**5**
Electric Power Sector Emissions					
CO_2 (*million metric tons*)	7.55	19.47	**46.87**	183.46	186.87
CH_4 (*thousand tons*)	0.45	1.15	**2.78**	10.87	11.08
N_2O (*thousand tons*)	0.06	0.16	**0.38**	1.47	1.50
SO_2 (*thousand tons*)	1.94	5.00	**12.03**	47.04	47.96
NO_X (*thousand tons*)	3.06	7.89	**18.98**	74.28	75.68
Hg (*tons*)	0.01	0.03	**0.08**	0.32	0.33
Upstream Emissions					
CO_2 (*million metric tons*)	0.74	1.89	**4.53**	17.69	18.09
CH_4 (*thousand tons*)	67.31	172.33	**413.37**	1,613.11	1,649.54
N_2O (*thousand tons*)	0.00	0.01	**0.02**	0.08	0.08
SO_2 (*thousand tons*)	0.04	0.11	**0.26**	1.00	1.03
NO_X (*thousand tons*)	11.54	29.54	**70.87**	276.55	282.80
Hg (*tons*)	0.00	0.00	**0.00**	0.00	0.00
Total FFC Emissions					
CO_2 (*million metric tons*)	8.29	21.36	**51.40**	201.15	204.96
CH_4 (*thousand tons*)	67.76	173.48	**416.15**	1,623.98	1,660.62
N_2O (*thousand tons*)	0.06	0.16	**0.40**	1.55	1.58
SO_2 (*thousand tons*)	1.98	5.11	**12.29**	48.05	48.99
NO_X (*thousand tons*)	14.60	37.43	**89.85**	350.84	358.48
Hg (*tons*)	0.01	0.03	**0.08**	0.32	0.33

Table V.47 Cumulative Emissions Reduction for Low-voltage Dry-type Distribution Transformers Shipped During the Period 2029–2058

	Trial Standard Level				
	1	2	3	4	5
Electric Power Sector Emissions					
CO_2 (*million metric tons*)	6.63	9.85	**28.45**	39.61	42.01
CH_4 (*thousand tons*)	0.40	0.59	**1.70**	2.37	2.51
N_2O (*thousand tons*)	0.05	0.08	**0.23**	0.32	0.34
SO_2 (*thousand tons*)	1.71	2.54	**7.32**	10.20	10.82
NO_X (*thousand tons*)	2.71	4.03	**11.64**	16.21	17.19
Hg (*tons*)	0.01	0.02	**0.05**	0.07	0.07
Upstream Emissions					
CO_2 (*million metric tons*)	0.66	0.98	**2.83**	3.95	4.19
CH_4 (*thousand tons*)	60.20	89.48	**258.26**	359.92	381.91
N_2O (*thousand tons*)	0.00	0.00	**0.01**	0.02	0.02
SO_2 (*thousand tons*)	0.04	0.06	**0.16**	0.23	0.24
NO_X (*thousand tons*)	10.32	15.34	**44.28**	61.70	65.48
Hg (*tons*)	0.00	0.00	**0.00**	0.00	0.00
Total FFC Emissions					
CO_2 (*million metric tons*)	7.29	10.83	**31.28**	43.56	46.20
CH_4 (*thousand tons*)	60.60	90.07	**259.96**	362.28	384.42
N_2O (*thousand tons*)	0.06	0.08	**0.24**	0.34	0.36
SO_2 (*thousand tons*)	1.75	2.59	**7.49**	10.43	11.06
NO_X (*thousand tons*)	13.03	19.37	**55.92**	77.92	82.67
Hg (*tons*)	0.01	0.02	**0.05**	0.07	0.07

Table V.48 Cumulative Emissions Reduction for Medium-voltage Dry-type Distribution Transformers Shipped During the Period 2029–2058

	Trial Standard Level				
	1	2	3	4	5
Electric Power Sector Emissions					
CO_2 (*million metric tons*)	1.69	**2.36**	6.86	8.95	10.64
CH_4 (*thousand tons*)	0.10	**0.14**	0.41	0.54	0.64
N_2O (*thousand tons*)	0.01	**0.02**	0.06	0.07	0.09
SO_2 (*thousand tons*)	0.44	**0.61**	1.78	2.32	2.76
NO_X (*thousand tons*)	0.69	**0.97**	2.81	3.67	4.36
Hg (*tons*)	0.00	**0.00**	0.01	0.02	0.02
Upstream Emissions					
CO_2 (*million metric tons*)	0.17	**0.24**	0.69	0.90	1.07
CH_4 (*thousand tons*)	15.50	**21.72**	63.07	82.36	98.01
N_2O (*thousand tons*)	0.00	**0.00**	0.00	0.00	0.00
SO_2 (*thousand tons*)	0.01	**0.01**	0.04	0.05	0.06
NO_X (*thousand tons*)	2.66	**3.72**	10.81	14.12	16.80
Hg (*tons*)	0.00	**0.00**	0.00	0.00	0.00
Total FFC Emissions					
CO_2 (*million metric tons*)	1.86	**2.59**	7.55	9.85	11.72
CH_4 (*thousand tons*)	15.60	**21.86**	63.48	82.90	98.65
N_2O (*thousand tons*)	0.01	**0.02**	0.06	0.08	0.09
SO_2 (*thousand tons*)	0.45	**0.63**	1.82	2.37	2.82
NO_X (*thousand tons*)	3.35	**4.69**	13.62	17.79	21.17
Hg (*tons*)	0.00	**0.00**	0.01	0.02	0.02

As part of the analysis for this rule, DOE estimated monetary benefits likely to result from the reduced emissions of CO_2 that DOE estimated for each of the considered TSLs for distribution transformers. Section IV.L.1.a of this document discusses the estimated SC–CO_2 values that DOE used. Table V.49 presents the value of CO_2 emissions reduction at each TSL for each of the SC–CO_2 cases. The time-series of annual values is presented for the selected TSL in chapter 14 of the final rule TSD.

Table V.49 Present Value of CO_2 Emissions Reduction for all Distribution Transformers Shipped During the Period 2029–2058

TSL	SC-CO_2 Case			
	Discount Rate and Statistics			
	5% Average	3% Average	2.5% Average	3% 95th percentile
	million 2022$			
Liquid-immersed Distribution Transformers				
1	52.1	234.1	371.4	707.3
2	134.4	603.2	957.1	1,822.6
3	323.4	1,451.9	2,303.6	4,386.6
4	1,265.4	5,681.0	9,013.9	17,164.2
5	1,289.5	5,789.0	9,185.1	17,490.4
Low-voltage Dry Type Distribution Transformers				
1	50.2	223.4	353.7	675.5
2	74.5	331.9	525.3	1,003.3
3	215.2	958.5	1,517.3	2,897.9
4	299.7	1,334.8	2,113.0	4,035.7
5	317.8	1,415.8	2,241.0	4,280.3
Medium-voltage Distribution Transformers				
1	12.8	56.9	90.0	171.9
2	17.9	79.5	125.9	240.4
3	52.0	231.4	366.3	699.7
4	67.8	302.0	478.0	912.9
5	80.6	359.1	568.4	1,085.6

As discussed in section IV.L.2 of this document, DOE estimated the climate benefits likely to result from the reduced emissions of methane and N_2O that DOE estimated for each of the considered TSLs for distribution transformers. Table V.50 presents the value of the CH_4 emissions reduction at each TSL, and Table V.51 presents the value of the N_2O emissions reduction at each TSL. The time-series of annual values is presented for the selected TSL in chapter 14 of the final rule TSD.

Table V.50 Present Value of Methane Emissions Reduction for all Distribution Transformers Shipped During the Period 2029–2058

TSL	SC-CH_4 Case			
	Discount Rate and Statistics			
	5% Average	3% Average	2.5% Average	3% 95th percentile
	million 2022$			
Liquid-immersed Distribution Transformers				
1	20.1	63.9	90.4	169.3
2	51.3	163.6	231.6	433.5
3	123.2	392.5	555.4	1,039.9
4	480.6	1,531.5	2,167.5	4,058.0
5	491.4	1,566.1	2,216.4	4,149.6
Low-voltage Dry Type Distribution Transformers				
1	19.5	61.6	87.0	163.2
2	29.0	91.6	129.3	242.5
3	83.8	264.3	373.3	700.0
4	116.7	368.3	520.2	975.5
5	123.9	390.8	552.0	1,035.1
Medium-voltage Distribution Transformers				
1	5.0	15.9	22.4	42.0
2	7.0	22.2	31.4	58.9
3	20.5	64.5	91.1	170.9
4	26.7	84.3	119.0	223.2
5	31.8	100.3	141.6	265.6

Table V.51 Present Value of Nitrous Oxide Emissions Reduction for all Distribution Transformers Shipped During the Period 2029–2058

TSL	SC-N_2O Case			
	Discount Rate and Statistics			
	5% Average	3% Average	2.5% Average	3% 95th percentile
	million 2022$			
Liquid-immersed Distribution Transformers				
1	0.2	0.7	1.0	1.8
2	0.4	1.7	2.7	4.6
3	1.0	4.1	6.5	11.1
4	3.9	16.2	25.4	43.4
5	3.9	16.5	25.9	44.2
Low-voltage Dry Type Distribution Transformers				
1	0.2	0.6	1.0	1.7
2	0.2	1.0	1.5	2.5
3	0.7	2.7	4.3	7.3
4	0.9	3.8	6.0	10.2
5	1.0	4.1	6.3	10.8
Medium-voltage Distribution Transformers				
1	0.0	0.2	0.3	0.4
2	0.1	0.2	0.4	0.6
3	0.2	0.7	1.0	1.8
4	0.2	0.9	1.4	2.3
5	0.2	1.0	1.6	2.8

DOE is well aware that scientific and economic knowledge about the contribution of CO_2 and other GHG emissions to changes in the future global climate and the potential resulting damages to the global and U.S. economy continues to evolve rapidly. DOE, together with other Federal agencies, will continue to review 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. DOE notes, however, that the adopted standards would be economically justified even without inclusion of monetized benefits of reduced GHG emissions.

DOE also estimated the monetary value of the economic benefits associated with NO_X and SO_2 emissions reductions anticipated to result from the considered TSLs for distribution transformers. The dollar-per-ton values that DOE used are discussed in section IV.L of this document. Table V.52 presents the present value for NO_X emissions reduction for each TSL calculated using 7-percent and 3-percent discount rates, and Table V.53 presents similar results for SO_2 emissions reductions. The results in these tables reflect application of EPA's low dollar-per-ton values, which DOE used to be conservative. The time-series of annual values is presented for the selected TSL in chapter 14 of the final rule TSD.

Table V.52 Present Value of NO_X Emissions Reduction for all Distribution Transformers Shipped During the Period 2029–2058

EC	TSL	7% Discount Rate	3% Discount Rate
		million 2022$	
Liquid-immersed Distribution Transformers			
1A	1	11.8	39.6
	2	18.8	63.2
	3	273.3	917.6
	4	273.3	917.6
	5	278.5	935.1
1B	1	70.3	236.2
	2	147.0	493.8
	3	147.0	493.8
	4	1,946.0	6,533.7
	5	1,943.4	6,525.4
2A	1	11.3	38.0
	2	34.6	116.3
	3	320.7	1,076.7
	4	320.7	1,076.7
	5	324.9	1,090.9
2B	1	57.0	191.5
	2	185.4	622.4
	3	185.4	622.4
	4	1,077.4	3,617.5
	5	1,111.4	3,731.7
12	1	N/A	N/A
	2	N/A	N/A
	3	N/A	N/A
	4	N/A	N/A
	5	37.7	126.7
Low-voltage Dry-Type Distribution Transformers			
3	1	6.4	20.4
	2	13.3	42.3
	3	24.0	76.6
	4	41.9	133.8
	5	47.3	150.9
4	1	142.3	454.4
	2	207.7	663.3
	3	613.8	1,960.5
	4	846.8	2,704.6
	5	895.6	2,860.7
Medium-voltage Dry-Type Distribution Transformers			
5	1	0.1	0.3
	2	0.2	0.7
	3	0.6	1.8
	4	1.0	3.1
	5	1.4	4.4
6	1	4.8	15.2
	2	5.8	18.6
	3	10.5	33.6
	4	13.7	43.8
	5	16.8	53.7
7	1	0.1	0.3
	2	0.4	1.4
	3	0.9	2.9
	4	1.0	3.3
	5	1.3	4.1
8	1	17.8	56.9
	2	26.9	86.0
	3	89.1	284.7
	4	114.0	364.1
	5	136.5	435.9
9	1	0.1	0.3
	2	0.2	0.5
	3	0.3	1.0
	4	0.5	1.7
	5	0.6	1.9
10	1	15.3	49.0
	2	19.9	63.7
	3	54.0	172.4
	4	72.6	231.9
	5	84.8	271.0

Table V.53 Present Value of SO_2 Emissions Reduction by Equipment Class for all Distribution Transformers Shipped During the Period 2029–2058

EC	TSL	7% Discount Rate	3% Discount Rate
		million 2022$	
Liquid-immersed Distribution Transformers			
1A	1	2.3	7.6
	2	3.7	12.1
	3	53.7	177.9
	4	53.7	177.9
	5	54.5	180.8
1B	1	13.6	45.3
	2	28.7	95.2
	3	28.7	95.2
	4	382.1	1,266.8
	5	380.7	1,262.1
2A	1	2.2	7.4
	2	6.8	22.5
	3	62.9	208.6
	4	62.9	208.6
	5	63.7	211.1
2B	1	11.2	37.0
	2	36.3	120.4
	3	36.3	120.4
	4	211.5	701.3
	5	217.8	722.1
12	1	N/A	N/A
	2	N/A	N/A
	3	N/A	N/A
	4	N/A	N/A
	5	7.4	24.5
Low-voltage Dry-Type Distribution Transformers			
3	1	1.2	3.9
	2	2.6	8.0
	3	4.6	14.5
	4	8.1	25.4
	5	9.1	28.6
4	1	27.3	86.1
	2	39.9	125.6
	3	117.9	371.3
	4	162.6	512.1
	5	171.9	541.6
Medium-voltage Dry-Type Distribution Transformers			
5	1	0.0	0.1
	2	0.0	0.1
	3	0.1	0.3
	4	0.2	0.6
	5	0.3	0.8
6	1	0.9	2.9
	2	1.1	3.5
	3	2.0	6.3
	4	2.6	8.3
	5	3.2	10.1
7	1	0.0	0.0
	2	0.1	0.3
	3	0.2	0.5
	4	0.2	0.6
	5	0.2	0.8
8	1	3.4	10.7
	2	5.1	16.2
	3	17.1	53.8
	4	21.8	68.7
	5	26.1	82.3
9	1	0.0	0.1
	2	0.0	0.1
	3	0.1	0.2
	4	0.1	0.3
	5	0.1	0.4
10	1	2.9	9.2
	2	3.8	12.0
	3	10.3	32.5
	4	13.9	43.8
	5	16.2	51.1

Not all the public health and environmental benefits from the reduction of greenhouse gases, NO_X, and SO_2 are captured in the values above, and additional unquantified benefits from the reductions of those pollutants as well as from the reduction of direct PM and other co-pollutants may be significant. DOE has not included monetary benefits of the reduction of Hg emissions because the amount of reduction is very small.

7. 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)) In this final rule, DOE considered the near-term impact of amended standards on existing distribution transformer shortages, on the domestic electrical steel supply, and on projected changes to the transformer market to support electrification.

8. Summary of Economic Impacts

Table V.54 presents the NPV values that result from adding the estimates of the economic benefits resulting from reduced GHG and NO_X and SO_2 emissions to the NPV of consumer benefits calculated for each TSL considered in this rulemaking. The consumer benefits are domestic U.S. monetary savings that occur as a result of purchasing the covered equipment and are measured for the lifetime of products shipped during the period 2029–2058. The climate benefits associated with reduced GHG emissions resulting from the adopted standards are global benefits and are also calculated based on the lifetime of distribution transformers shipped during the period 2029–2058.

Table V.54 Consumer NPV Combined with Present Value of Climate Benefits and Health Benefits

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Liquid-immersed Distribution Transformers					
3% discount rate for Consumer NPV and Health Benefits (billion 2022$)					
5% Average SC-GHG case	2.06	3.60	7.57	29.26	13.03
3% Average SC-GHG case	2.28	4.18	8.97	34.74	18.61
2.5% Average SC-GHG case	2.45	4.61	9.99	38.71	22.67
3% 95th percentile SC-GHG case	2.86	5.67	12.56	48.77	32.93
7% discount rate for Consumer NPV and Health Benefits (billion 2022$)					
5% Average SC-GHG case	0.66	1.01	2.11	8.90	-1.18
3% Average SC-GHG case	0.89	1.59	3.52	14.38	4.40
2.5% Average SC-GHG case	1.05	2.01	4.53	18.36	8.46
3% 95th percentile SC-GHG case	1.47	3.08	7.10	28.41	18.72
Low-voltage Distribution Transformers					
3% discount rate for Consumer NPV and Health Benefits (billion 2022$)					
5% Average SC-GHG case	0.77	1.07	3.14	4.68	4.57
3% Average SC-GHG case	0.98	1.39	4.07	5.97	5.93
2.5% Average SC-GHG case	1.14	1.62	4.74	6.90	6.92
3% 95th percentile SC-GHG case	1.54	2.22	6.45	9.28	9.45
7% discount rate for Consumer NPV and Health Benefits (billion 2022$)					
5% Average SC-GHG case	2.08	2.98	9.40	13.94	13.88
3% Average SC-GHG case	2.30	3.30	10.33	15.23	15.25
2.5% Average SC-GHG case	2.46	3.53	11.00	16.16	16.24
3% 95th percentile SC-GHG case	2.85	4.12	12.71	18.54	18.77
Medium-voltage Distribution Transformers					
3% discount rate for Consumer NPV and Health Benefits (billion 2022$)					
5% Average SC-GHG case	0.19	0.12	0.51	0.52	0.32
3% Average SC-GHG case	0.25	0.20	0.73	0.81	0.67
2.5% Average SC-GHG case	0.29	0.25	0.89	1.02	0.92
3% 95th percentile SC-GHG case	0.39	0.40	1.31	1.56	1.56
7% discount rate for Consumer NPV and Health Benefits (billion 2022$)					
5% Average SC-GHG case	0.52	0.44	1.81	2.01	1.75
3% Average SC-GHG case	0.57	0.52	2.04	2.30	2.10
2.5% Average SC-GHG case	0.61	0.58	2.20	2.51	2.35
3% 95th percentile SC-GHG case	0.71	0.72	2.61	3.05	2.99

C. Conclusion

When considering new or amended energy conservation standards, the standards that DOE adopts for any type (or class) of covered equipment must be designed to achieve the maximum improvement in energy efficiency that the Secretary determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 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 by, to the greatest extent practicable, considering the seven statutory factors discussed previously. (42 U.S.C. 6316(a); 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. 6316(a); 42 U.S.C. 6295(o)(3)(B))

For this final rule, DOE considered the impacts of amended standards for distribution transformers at each TSL, beginning with the maximum technologically feasible 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 both technologically feasible and economically justified and saves a significant amount of energy.

To aid the reader as DOE discusses the benefits and/or burdens of each TSL, tables in this section present a summary of the results of DOE's quantitative analysis for each TSL. 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 consumers who may be disproportionately affected by a national standard and impacts on employment.

DOE also notes that the economics literature provides a wide-ranging discussion of how consumers trade off upfront costs and energy savings in the absence of government intervention. Much of this literature attempts to explain why consumers appear to undervalue energy efficiency improvements. There is evidence that consumers undervalue future energy savings as a result of: (1) a lack of information; (2) a lack of sufficient salience of the long-term or aggregate benefits; (3) a lack of sufficient savings to warrant delaying or altering purchases; (4) excessive focus on the short term, in the form of inconsistent weighting of future energy cost savings relative to available returns on other investments; (5) computational or other difficulties associated with the evaluation of relevant tradeoffs; and (6) a divergence in incentives (for example, between renters and owners, or builders and purchasers). Having less than perfect foresight and a high degree of uncertainty about the future, consumers may trade off these varieties of investments at a higher-than-expected rate between current consumption and uncertain future energy cost savings.

1. Benefits and Burdens of TSLs Considered for Liquid-Immersed Distribution Transformer Standards

Table V.55 and Table V.56 summarize the quantitative impacts estimated for each TSL for liquid-immersed distribution transformers. The national impacts are measured over the lifetime of distribution transformers purchased in the 30-year period that begins in the anticipated year of compliance with amended standards (2029–2058). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. DOE is presenting monetized benefits of GHG emissions reductions in accordance with the applicable Executive Orders, and DOE would reach the same conclusion presented in this notice in the absence of the social cost of greenhouse gases, including the Interim Estimates presented by the Interagency Working Group. The efficiency levels contained in each TSL are described in section V.A of this document.

Table V.55 Summary of Analytical Results for Liquid-Immersed Distribution Transformer TSLs: National Impacts (for Units Shipped between 2029 – 2058)

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Cumulative FFC National Energy Savings					
Quads	0.45	1.14	**2.73**	10.67	10.91
Cumulative FFC Emissions Reduction					
CO_2 (*million metric tons*)	8.29	21.36	**51.40**	201.15	204.96
CH_4 (*thousand tons*)	67.76	173.48	**416.15**	1,623.98	1,660.62
N_2O (*thousand tons*)	0.06	0.16	**0.40**	1.55	1.58
NO_X (*thousand tons*)	14.60	37.43	**89.85**	350.84	358.48
SO_2 (*thousand tons*)	1.98	5.11	**12.29**	48.05	48.99
Hg (*tons*)	0.01	0.03	**0.08**	0.32	0.33
Present Value of Benefits and Costs (*7% discount rate, billion 2022$*)					
Consumer Operating Cost Savings	0.52	1.00	**1.99**	6.52	8.52
Climate Benefits*	0.30	0.77	**1.85**	7.23	7.37
Health Benefits**	0.18	0.46	**1.11**	4.33	4.42
Total Benefits†	1.00	2.23	**4.95**	18.08	20.31
Consumer Incremental Product Costs‡	0.11	0.64	**1.43**	3.70	15.91
Consumer Net Benefits	0.41	0.36	**0.56**	2.82	-7.39
Total Net Benefits	0.89	1.59	**3.52**	14.38	4.40
Present Value of Benefits and Costs (*3% discount rate, billion 2022$*)					
Consumer Operating Cost Savings	1.59	3.06	**6.07**	19.88	25.97
Climate Benefits*	0.30	0.77	**1.85**	7.23	7.37
Health Benefits**	0.60	1.55	**3.71**	14.50	14.81
Total Benefits†	2.49	5.38	**11.63**	41.61	48.16
Consumer Incremental Product Costs‡	0.21	1.19	**2.66**	6.87	29.54
Consumer Net Benefits	1.38	1.87	**3.41**	13.01	-3.57
Total Net Benefits	2.28	4.18	**9.97**	34.74	18.61

Note: This table presents the costs and benefits associated with distribution transformers shipped during the period 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped during the period 2029−2058.

* Climate benefits are calculated using four different estimates of the SC-CO_2, SC-CH_4 and SC-N_2O. Together, these represent the global SC-GHG. For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for NO_X and SO_2) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

Table V.56 Summary of Analytical Results for Liquid-Immersed Distribution Transformer TSLs: Manufacturer and Consumer Impacts (for Units Shipped between 2029 – 2058)

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (million 2022$) (No-new-standards case INPV = 1,792)	1,726 – 1,730	1,715 - 1,734	**1,647 – 1,681**	1,316 – 1,404	1,106 – 1,454
Industry NPV (% change)	(3.7) – (3.5)	(4.3) – (3.2)	**(8.1) – (6.2)**	(26.6) – (21.6)	(38.3) – (18.8)
Consumer Average LCC Savings (2022$)					
1A	90	49	**657**	657	-2,686
1B	36	48	**48**	317	-187
2A	75	48	**851**	851	407
2B	843	498	**498**	5,301	-2,977
12	N/A	N/A	N/A	N/A	770
Shipment-Weighted Average*	63	62	**101**	496	-289
Consumer Simple PBP (years)					
1A	3.8	19.1	**10.7**	10.7	42.1
1B	6.9	19.5	**19.5**	7.4	28.1
2A	8.4	14.7	**9.2**	9.2	15.1
2B	9.0	14.6	**14.6**	9.0	19.3
12	N/A	N/A	N/A	N/A	14.8
Shipment-Weighted Average*	6.7	19.1	**18.8**	7.7	28.6
Percent of Consumers that Experience a Net Cost					
1A	37.8	55.7	27.5	27.5	89.0
1B	29.3	28.5	28.5	7.1	59.3
2A	15.3	38.4	7.1	7.1	28.7
2B	15.0	39.6	39.6	7.6	40.1
12	N/A	N/A	N/A	N/A	45.2
Shipment-Weighted Average*	29.7	31.4	29.2	8.1	60.8

DOE first considered TSL 5, which represents the max-tech efficiency levels across all product classes of liquid-immersed distribution transformers essentially requiring the shift to the most-efficient electrical steel for core fabrication and larger and heavier distribution transformers as more material is needed to support the efficiency gains. TSL 5 would save an estimated 10.91 quads of energy, an amount DOE considers significant. Under TSL 5, the NPV of consumer benefit would be −$7.39 billion using a discount rate of 7 percent, and −$3.57 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 204.96 Mt of CO_2, 49.0 thousand tons of SO_2, 358.5 thousand tons of NO_X, 0.3 tons of Hg, 1,660.6 thousand tons of CH_4, and 1.6 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 5 is $7.37 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 5 is $4.42 billion using a 7-percent discount rate and $14.81 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 5 is $4.40 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 5 is $18.61 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a standard level is economically justified.

At TSL 5, the average LCC impact ranges from -$2,977 for equipment class 2B to $770 for equipment class 12. The median PBP ranges from 14.8 years for equipment class 12 to 42.1 years for equipment class 1A. The fraction of consumers experiencing a net LCC cost ranges from 28.7 percent for equipment class 2A to 89.0 percent for equipment class 1A.

At TSL 5, the projected change in INPV ranges from a decrease of $686 million to a decrease of $338 million, which corresponds to decreases of 38.3 percent and 18.8 percent, respectively. This decrease is primarily driven by the investments needed to move the entire liquid-immersed distribution transformer market to the most-efficient designs, including converting their production facilities to produce and accommodate amorphous core technology. DOE estimates that industry must invest $697 million to comply with standards set at TSL 5.

The Secretary concludes that at TSL 5 for liquid-immersed distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on many consumers as indicated by lengthy PBPs, the percentage of customers who would experience LCC increases, negative consumer NPV at both 3- and 7-percent discount rates, and the capital and engineering costs that would result in a reduction in INPV for manufacturers. At TSL 5, the LCC savings are negative for most liquid-immersed distribution transformers, indicating there is a substantial risk that a disproportionate number of consumers will incur increased costs; these costs are also reflected in simple PBP estimates that approach average transformer lifetimes for some equipment. NPVs are calculated for equipment shipped over the period of 2029 through 2058 (see section IV.H.3 of this document). Distribution transformers are durable equipment with a maximum lifetime estimated at 60 years (see section IV.F.8), accruing operating cost savings through 2117. When considered over this time period, the discounted value of the incremental equipment costs outweighs the discounted value of the operating costs savings. Incremental equipment costs are incurred in the first year of equipment life, while operating cost savings occur throughout the equipment lifetime, with later years heavily discounted. Further, there is risk of greater reduction in INPV at max-tech if manufacturers maintain their operating profit in the presence of amended efficiency standards on account of having higher costs but similar profits. The benefits of max-tech efficiency levels for liquid-immersed distribution transformers do not outweigh the negative impacts to consumers and manufacturers. Consequently, the Secretary has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, a level at which DOE estimates a likely shift in the electrical steel used for distribution transformer cores for liquid-immersed distribution transformers. TSL 4 would save an estimated 10.67 quads of energy, an amount DOE considers significant. Under TSL 4, the NPV of consumer benefit would be $2.82 billion using a discount rate of 7 percent, and $13.01 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 201.15 Mt of CO_2, 48.0 thousand tons of SO_2, 350.8 thousand tons of NO_X, 0.3 tons of Hg, 1,624.0 thousand tons of CH_4, and 1.5 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 4 is $7.23 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 4 is $4.33 billion using a 7-percent discount rate and $14.50 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 4 is $14.38 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $34.74 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a standard level is economically justified.

At TSL 4, the average LCC impact ranges from $317 for equipment class 1B to $5,301 for equipment class 2B. The median PBP ranges from 7.4 years for equipment class 1B to 10.7 years for equipment class 1A. The fraction of consumers experiencing a net LCC cost ranges from 7.1percent for equipment classes 1B and 2A to 27.5 percent for equipment class 1A.

At TSL 4, the projected change in INPV ranges from a decrease of $476 million to a decrease of $388 million, which corresponds to decreases of 26.6 percent and 21.6 percent, respectively. These estimates are driven by DOE's estimate that liquid-immersed distribution transformer manufacturers will need to invest $587 million to comply with standards set at TSL 4 to produce or accommodate amorphous core technology.

The energy savings under TSL 4 are primarily achievable by using amorphous cores and DOE believes manufacturers will likely choose this technology pathway in order to meet TSL 4 efficiency levels due to the relative cost of meeting these levels with amorphous and GOES cores. In the present market, distribution transformers are primarily designed using GOES cores and the production equipment used for GOES core distribution transformer manufacturing is not the same. While DOE understands that amorphous core distribution transformers are technically feasible for liquid-immersed, DOE also understands that current domestic supply would need to ramp up significantly for amorphous steel to support this market.

The transition to amorphous cores is constrained in two important ways. First, amorphous cores require amorphous steel. Supply of amorphous steel for transformer cores is not inherently constrained. Supply, including domestic supply, could increase in the face of increased demand.

For example, both global and domestic annual production capacity of amorphous ribbon is greater now than it was leading up to the April 2013 Standards Final Rule, with global annual production capacity of amorphous ribbon (estimated to be approximately 150,000–250,000 metric tons) approximately equal to the U.S. annual demand for core steel in distribution transformer applications (estimated to be approximately 225,000 metric tons). While additional amorphous ribbon capacity would be required to serve the entirety of the U.S. distribution transformer market, in addition to existing global applications, it is likely that supply would increase quickly in response to increased demand from standards. Following the April 2013 Standards Final Rule, amorphous ribbon capacity grew, although amorphous ribbon demand did not grow in-kind. As such, excess amorphous ribbon capacity already exists that could be utilized to serve a larger portion of the distribution transformer market, if demand were to increase. Further, the response of amorphous ribbon manufacturers following the April 2013 Standards Final Rule, as well as public announcements of development in amorphous core production capacity since the January 2023 NOPR, demonstrate that amorphous ribbon and core capacity can be added quickly if suppliers anticipate demand. As such, the supply of amorphous metal would likely increase in response to amended standards that favored amorphous ribbon as the optimal design option. Stakeholders have expressed a willingness to increase supply to match any potential demand created by an amended efficiency standard. As noted, in the current market, sales of amorphous ribbon are limited by demand for amorphous cores rather than any constraints on production capacity. Therefore, in the presence of an amended standard, it is expected that amorphous ribbon capacity would quickly rise to meet demand before the effective date of any amended energy conservation standards.

However, and secondly, demand for amorphous steel is constrained by distribution transformer manufacturers' willingness and ability to invest in in the capital equipment required to produce and process amorphous metal cores. The production pathway for both amorphous core and GOES core transformers is similar once this investment in the equipment has been made. However, the transition from production of GOES cores to production of amorphous cores would require significant investment by distribution transformer manufacturers that produce their own cores. At TSL 4, most existing core production equipment, which is predominantly set up to produce GOES cores, would need to be replaced with amorphous core production equipment. Given existing supply challenges and long lead times for distribution transformers, it is unclear if most manufacturers would have the capacity to complete the necessary investments in amorphous core production equipment within the 5-year compliance period and maintain their existing GOES production lines to supply the current market demand without increasing near-term distribution transformer lead times. If manufacturers anticipate requiring more than 5 years to fully convert production or add production of amorphous cores, they may prioritize maintaining lead times by continuing to produce transformers with GOES cores. If GOES cores are used to meet TSL 4, the resulting designs are substantially larger and more expensive than amorphous core designs, with some size capacities in DOE's modelling unable to meet TSL 4 at all with GOES. Conversely, if manufacturers prioritize a transition to amorphous cores over maintaining lead times, they may prioritize investing in replacing existing production equipment, rather than in new additive capacity. This could inhibit manufacturers' abilities to invest in necessary capacity upgrades to help resolve the existing transformer shortages.

In addition to the production equipment and investments needed to support a TSL 4 transition by distribution transformers, DOE understands that the current workforce supporting the distribution transformer manufacturer is also limited in their experience with amorphous core production. DOE understands from the many stakeholder comments that current workforce challenges within the distribution transformer industry may be exacerbated in the short-term if a full transition to TSL 4 is required. While DOE understands most manufacturers currently can produce liquid-immersed transformers at TSL 4 efficiencies, DOE also understand that due to the lower volume of amorphous cores in the market today many production facilities outsource amorphous core production but produce GOES cores in-house. DOE believes that if TSL 4 efficiencies were required for liquid-immersed distribution transformers the sourcing decisions on core fabrication would not largely change from what they are today as these are inherent business decisions that balance quality, control, and lead-times. Therefore, despite offering liquid-immersed transformers at TSL 4 efficiencies, manufacturers do not yet have a lot of experience fabricating amorphous cores and will take significant training and time in order to support a transition of this magnitude. Some manufacturers raised questions in comments about their ability to invest in both the capital as well as the workforce in the time provided to transition to TSL 4, while maintaining their supply needs for GOES transformers in the near-term.

DOE notes that while the January 2023 NOPR proposed standards at TSL 4, distribution transformer shortages persisted throughout 2023. DOE further notes that hundreds of millions of dollars in investments have been announced by distribution transformer manufacturers to add capacity to resolve the existing transformer shortages and those investments are currently undergoing the design, permitting, engineering, and construction process needed to begin production with scheduled completions typically targeting 24 to 36 months. DOE updated its analysis of conversion costs in this final rule based on stakeholder feedback and are the costs are now greater than the costs analyzed in the January 2023 NOPR. Investing in conversion costs and workforce training, in addition to manufacturers investments to increase capacity, without offering flexibility for manufacturers to add amorphous capacity in an additive manner has led DOE to conclude that TSL 4 offers substantial risk that could extend current transformer shortages longer they otherwise would be.

The Secretary concludes that at TSL 4 for liquid-immersed distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the significant impact to manufacturers (a loss in INPV of up to 26.6 percent, conversion costs of approximately $587 million, and a free cash flow of −$125 million in the year leading up to the compliance year) and the risks that manufacturers would not be able to scale up amorphous core production capacity within the compliance period without significantly increasing distribution transformer lead times or maintaining very large and costly GOES core transformers after the compliance period. In addition, DOE has concerns about distribution transformer manufacturer's ability to maintain their existing GOES lines in the near-term, while training their workforce to become comfortable with producing transformers cores with amorphous ribbon. Further, as discussed in section IV.C.2.a, an inability of suppliers of amorphous ribbon to scale production and manufacturers to retool production lines for amorphous cores within the compliance period could lead to market uncertainty and disruption during a critical time. Several stakeholders have noted that given existing supply challenges, a total conversion to amorphous is not feasible in the near term. While this final rule considers a longer compliance period, the impacts of shortages are substantial, which may have an impact on grid reliability. Therefore, the risks of scale-up and compliance taking slightly longer, due to any number of unforeseen challenges, could have substantial impacts. The benefits of TSL 4 for liquid-immersed distribution transformer do not outweigh the risks when considering the potential impacts to the broader distribution transformer supply chain. Consequently, the Secretary has concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3. TSL 3 would save an estimated 2.73 quads of energy, an amount DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $0.56 billion using a discount rate of 7 percent, and $3.41 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 51.40 Mt of CO_2, 12.3 thousand tons of SO_2, 89.9 thousand tons of NO_X, 0.1 tons of Hg, 416.2 thousand tons of CH_4, and 0.4 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 3 is $1.85 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 3 is $1.11 billion using a 7-percent discount rate and $3.71 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 3 is $3.52 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 3 is $9.97 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a standard level is economically justified.

At TSL 3, the average LCC impact ranges from $48 for equipment class 1B to $851 for equipment class 2A. The median PBP ranges from 9.2 years for equipment class 2A to 19.5 years for equipment class 1B. The fraction of consumers experiencing a net LCC cost ranges from 7.1 percent for equipment class 2A to 39.6 percent for equipment class 2B.

At TSL 3, the projected change in INPV ranges from a decrease of $145 million to a decrease of $111 million, which corresponds to decreases of 8.1 percent and 6.2 percent, respectively. DOE estimates that industry must invest $187 million to comply with standards set at TSL 3.

After considering the analysis and weighing the benefits and burdens, the Secretary has concluded that a standard set at TSL 3 for liquid-immersed distribution transformers would be economically justified. Notably, the benefits to consumers outweigh the cost to manufacturers. At TSL 3, the average LCC savings are positive across all equipment classes. An estimated 29 percent of liquid-immersed distribution transformer consumers experience a net cost. DOE notes that if the shipments equipment classes 1B and 2B transition to amorphous cores from DOE's assumed rate of 3 percent to 10, or 25 percent, the maximum number of consumers experiencing a net cost decreases to 25 and 21 percent, respectively.[198] The FFC national energy savings are significant and the NPV of consumer benefits is positive using both a 3-percent and 7-percent discount rate when considered for all liquid-immersed distribution transformers subject to amended standards. When examined as individual equipment classes the NPV at 7 percent is positive for most equipment classes; with the exception of equipment class 2B, where the NPV at a 7 percent discount rate is negative: −$0.05 billion (see Table V.43). When equipment class 2B is considered with the addition of its associated health benefits of $0.22 billion at TSL 3 (see Table V.51 and Table V.52) the impacts become positive, with a net benefit of $0.17 billion. At TSL 3, the NPV of consumer benefits, even measured at the more conservative discount rate of 7 percent is larger than the maximum estimated manufacturers' loss in INPV. The standard levels at TSL 3 are economically justified even without weighing the estimated monetary value of emissions reductions. When those emissions reductions are included—representing $1.85 billion in climate benefits (associated with the average SC–GHG at a 3-percent discount rate), and $3.71 billion (using a 3-percent discount rate) or $1.11 billion (using a 7-percent discount rate) in health benefits—the rationale becomes stronger still.

Notably, the standards under TSL 3 would not pose the same near-term risks to distribution transformer availability. As compared to TSL 4, for which the energy savings are primarily achievable via amorphous cores, the energy savings under TSL 3 are achieved by using a mix of amorphous cores and GOES cores. Under TSL 3, DOE estimates that equipment class 1A and 2A will meet efficiency standards by transitioning to amorphous cores. If the unit sizes represented by these equipment classes shift entirely to amorphous, DOE estimates that approximately 48,000 metric tons of amorphous ribbon would be consumed, which is approximately equal to the current domestic amorphous ribbon production capacity (45,000 metric tons of domestic amorphous today). Under TSL 3, DOE estimates that the vast majority of liquid-immersed distribution transformers shipments (89 percent of units) could be met with GOES cores.

As noted, the transition from GOES cores to amorphous cores requires significant investment on the part of distribution transformer manufacturers that produce their own cores. However, core production equipment is somewhat flexible in that a given piece of equipment can produce a range of core sizes corresponding to a range of transformer kVA sizes. Given existing supply challenges facing the distribution transformer market, DOE assumes that manufacturers would prioritize maintaining lead times by continuing to produce transformers with GOES cores for transformer sizes where costs are approximately equal, even if a transformer with an amorphous core may be slightly less expensive to produce. Under TSL 3, DOE evaluated a higher efficiency level for Equipment Class 1A and 2A and a lower efficiency level for Equipment Class 1B and 2B. As such, manufacturers would have significant flexibility to invest in new capacity to meet efficiency standards while allowing for the continued use of current production equipment to ensure a robust short- to medium-term supply of distribution transformers.

TSL 3 results in positive LCCs for all equipment classes, whether expected to remain predominantly GOES-based (Equipment Class 1B and 2B) or predominantly amorphous-based (Equipment Class 1A and 2A).

Because only a portion of the market is expected to transition to amorphous at TSL 3 and because existing GOES production equipment can produce a variety of kVA sizes, manufacturers may invest in amorphous production equipment as additive capacity to serve those portions of the market where amorphous is most competitive. As such, manufacturers would have the flexibility of using existing GOES production equipment to serve the rest of the market, while adding additional amorphous production equipment that may help resolve the existing transformer shortages. Public statements from major liquid-immersed distribution transformer core manufacturers suggest that some have already begun investing in additive amorphous capacity in response to the January 2023 NOPR.[199 200 201]

Amorphous cores are expected to be the most cost-effective option for meeting efficiency levels for equipment class 1A and 2A. This suggests a future demand for amorphous ribbon and encourages both existing amorphous producers to increase supply and potential new producers to enter the market.

DOE expects manufacturers would prioritize amorphous core capital investments at the kVA ranges (*i.e.,* equipment class 1A and 2A), where amorphous cores are expected to be most cost competitive. However, if excess amorphous ribbon and amorphous core capacity exists, amorphous is also a cost-effective option for many of the other kVA ratings. While DOE has modeled equipment class 1B and 2B as meeting amended standards using exclusively GOES in its base analysis at TSL 3, DOE has included additional sensitivities in which amorphous core usage increases to a maximum of 25 percent at equipment class 1B and 2B. These scenarios further increase consumer benefits (see appendix 8G of the TSD).

DOE expects manufacturers would maintain some amount of GOES core production equipment and some amount of amorphous core production

[198] See: Appendix 8D of the final rule TSD for DOE's scenario examining the impacts resulting from increased amorphous adoption.

[199] Yahoo Finance, *Howard Industries cuts ribbon on Quitman plant,* November 3, 2023, Available online at: *https://finance.yahoo.com/news/howard-industries-cuts-ribbon-quitman-035900515.html.*

[200] JFE Shoji Power, ''What Got Us Here Won't Get Us to Where We Want to Go'', *You Will Be an Embarrassment to the Company,* Nov. 2023. *https://www.amazon.in/What-Here-Wont-Where-Want/dp/B0CMD84HRW.*

[201] Worthington Steel, *Investor Day,* Oct. 2023, Transcript. Available online at: *worthington-steel-investor-day-transcript-final-10-11-23.pdf* (*worthingtonenterprises.com.*)

equipment, thereby ensuring the U.S. distribution transformer market continues to be served by at least two domestic electrical steel providers, one producing GOES and one producing amorphous. This may support balanced supply chain for distribution transformers through a more diversified core steel supply, which is presently served predominantly by GOES production for which there is only one domestic supplier.

As stated, DOE conducts the walk-down analysis to determine the TSL that represents the maximum improvement in energy efficiency that is technologically feasible and economically justified as required under EPCA. The walk-down is not a comparative analysis, as a comparative analysis would result in the maximization of net benefits instead of energy savings that are technologically feasible and economically justified, which would be contrary to the statute. 86 FR 70892, 70908.

Although DOE has not conducted a comparative analysis to select the new energy conservation standards, DOE notes that TSL 3 ensures capacity for amorphous ribbon increases, on account of anticipated future demand, while leaving a considerable portion of the market at efficiency levels wherein GOES would remain cost competitive. As a result, this ensures that near-term shortages can be resolved and that overall U.S. electrification trends and support for domestic electrical steel industries are not compromised. As noted by numerous stakeholders, distribution transformers are crucial to supporting U.S. infrastructure, grid resiliency, and electrification goals. TSL 3 allows for efficiency standards to be met by additive capacity, which can help renormalize distribution transformer lead times. TSL 4 and TSL 5 did not include the same possibility for stakeholders to invest in an additive capacity to meet efficiency standards, thereby creating risks to the short- and medium-term supply of distribution transformers.

Although DOE considered amended standard levels for distribution transformers by grouping the efficiency levels for each equipment category into TSLs, DOE evaluates all analyzed efficiency levels in its analysis. The TSLs constructed by DOE to examine the impacts of amended energy efficiency standards for liquid-immersed distribution transformers align with the corresponding ELs defined in the engineering analysis, which the exception of TSL 3 which seeks to consider electrical steel capacity and demand growth limitations. For the ELs above baseline that compose TSL 3, DOE finds that LCC savings are positive for all equipment classes, with simple paybacks well below the average equipment lifetimes. DOE also finds that the estimated fraction of consumers who would be negatively impacted from a standard at TSL 3 to be 29.2 percent for all equipment classes. Importantly, DOE expects TSL 3 to be achievable with additive distribution transformer capacity in addition to capital conversion costs, thereby reducing both transformer and larger grid supply concerns.

Therefore, based on the previous considerations, DOE adopts the energy conservation standards for liquid-immersed distribution transformers at TSL 3. The amended energy conservation standards for distribution transformers, which are expressed as percentage efficiency at 50 percent PUL, are shown in Table V.57.

Table V.57 Amended Energy Conservation Standards for Liquid-Immersed Distribution Transformers

Single-Phase		Three-Phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.77%	15	98.92%
15	98.88%	30	99.06%
25	99.00%	45	99.14%
37.5	99.10%	75	99.22%
50	99.15%	112.5	99.29%
75	99.23%	150	99.33%
100	99.29%	225	99.38%
167	99.46%	300	99.42%
250	99.51%	500	99.38%
333	99.54%	750	99.43%
500	99.59%	1000	99.46%
667	99.62%	1500	99.51%
833	99.64%	2000	99.53%
		2500	99.55%
		3750	99.54%
		5000	99.53%

2. Benefits and Burdens of TSLs Considered for Low-Voltage Dry-Type Distribution Transformer Standards

Table V.58 and Table V.59 summarize the quantitative impacts estimated for each TSL for low-voltage dry-type distribution transformers. The national impacts are measured over the lifetime of distribution transformers purchased in the 30-year period that begins in the anticipated year of compliance with amended standards (2029–2058). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. DOE is presenting monetized benefits of GHG emissions reductions in accordance with the applicable Executive Orders, and DOE would reach the same conclusion presented in this notice in the absence of the social cost of greenhouse gases, including the Interim Estimates presented by the Interagency Working Group. The efficiency levels contained in each TSL are described in section V.A of this document.

Table V.58 Summary of Analytical Results for Low-Voltage Dry-Type Distribution Transformers TSLs: National Impacts (for Units Shipped between 2029 – 2058)

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Cumulative FFC National Energy Savings					
Quads	0.40	0.59	**1.71**	2.38	2.53
Cumulative FFC Emissions Reduction					
CO_2 (*million metric tons*)	7.29	10.83	**31.28**	43.56	46.20
CH_4 (*thousand tons*)	60.60	90.07	**259.96**	362.28	384.42
N_2O (*thousand tons*)	0.06	0.08	**0.24**	0.34	0.36
NO_X (*thousand tons*)	13.03	19.37	**55.92**	77.92	82.67
SO_2 (*thousand tons*)	1.75	2.59	**7.49**	10.43	11.06
Hg (*tons*)	0.01	0.02	**0.05**	0.07	0.07
Present Value of Benefits and Costs (*7% discount rate, billion 2022$*)					
Consumer Operating Cost Savings	0.47	0.70	**2.71**	4.06	4.14
Climate Benefits*	0.29	0.42	**1.23**	1.71	1.81
Health Benefits**	0.18	0.26	**0.76**	1.06	1.12
Total Benefits†	0.93	1.39	**4.70**	6.83	7.08
Consumer Incremental Product Costs‡	-0.05	0.00	**0.63**	0.86	1.14
Consumer Net Benefits	0.52	0.71	**2.08**	3.20	3.00
Total Net Benefits	0.98	1.39	**4.07**	5.97	5.93
Present Value of Benefits and Costs (*3% discount rate, billion 2022$*)					
Consumer Operating Cost Savings	1.35	2.03	**7.85**	11.74	11.99
Climate Benefits*	0.29	0.42	**1.23**	1.71	1.81
Health Benefits**	0.56	0.84	**2.42**	3.38	3.58
Total Benefits†	2.20	3.29	**11.50**	16.83	17.38
Consumer Incremental Product Costs‡	-0.10	-0.01	**1.17**	1.60	2.13
Consumer Net Benefits	1.45	2.04	**6.68**	10.14	9.86
Total Net Benefits	2.30	3.30	**10.33**	15.23	15.25

Note: This table presents the costs and benefits associated with distribution transformers shipped during the period 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped during the period 2029−2058.

* Climate benefits are calculated using four different estimates of the SC-CO_2, SC-CH_4 and SC-N_2O. Together, these represent the global SC-GHG. For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for NO_X and SO_2) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

Table V.59 Summary of Analytical Results for Low-Voltage Dry-Type Distribution Transformer TSLs: Manufacturer and Consumer Impacts (for Units Shipped between 2029 – 2058)

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (million 2022$) (No-new-standards case INPV = 212)	203	201 to 202	184 to 193	149 to 159	143 to 158
Industry NPV (% change)	(4.2) to (4.0)	(4.9) to (4.5)	(12.8) to (8.9)	(29.7) to (24.7)	(32.3) to (25.5)
Consumer Average LCC Savings (2022$)					
EC 3	501	333	321	551	517
EC 4	377	394	765	1,068	1,044
Shipment-Weighted Average*	389	388	724	1,020	995
Consumer Simple PBP (years)					
EC 3	0.0	3.6	7.4	7.4	8.9
EC 4	Instant	Instant	3.6	3.4	4.8
Shipment-Weighted Average*	Instant	Instant	3.9	3.8	5.2
Percent of Consumers that Experience a Net Cost					
EC 3	1	16	28	14	18
EC 4	6	9	9	2	3
Shipment-Weighted Average*	6	9	11	3	4

DOE first considered TSL 5, which represents the max-tech efficiency levels. TSL 5 would save an estimated 2.53 quads of energy, an amount DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $3.00 billion using a discount rate of 7 percent, and $9.86 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 46.20 Mt of CO_2, 11.1 thousand tons of SO_2, 82.7 thousand tons of NO_X, 0.1 tons of Hg, 384.4 thousand tons of CH_4, and 0.4 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 5 is $1.81 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 5 is $1.12 billion using a 7-percent discount rate and $3.58 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 5 is $5.93 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 5 is $15.25 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified.

At TSL 5, the average LCC impact ranges from $517 for equipment class 3 to $1,044 for equipment class 4. The median PBP ranges from 4.8 years for equipment class 4 to 8.9 years for equipment class 3. The fraction of consumers experiencing a net LCC cost ranges from 3 percent for equipment class 4 to 18 percent for equipment class 3.

At TSL 5, the projected change in INPV ranges from a decrease of $68.4 million to a decrease of $54.0 million, which corresponds to decreases of 32.3 percent and 25.5 percent, respectively. DOE estimates that industry must invest $91.8 million to comply with standards set at TSL 5.

The energy savings under TSL 5 are primarily achievable by using amorphous cores. The transition from GOES cores to amorphous cores requires significant investment on the part of the distribution transformer manufacturer if they produce their own cores. At TSL 5, most existing core production equipment would need to be replaced with amorphous core production equipment. Most LVDT manufacturers have little or no experience producing transformer designs with amorphous cores and little experience as to potential modifications that may need to be made to new protective equipment. Further, LVDT manufacturers tend to have considerably lower transformer core volumes than liquid-immersed manufacturers. As such, electrical steel manufacturers tend to prioritize service to liquid-immersed manufacturers over dry-type distribution transformer manufacturers. This creates a risk that, given the quantity of amorphous ribbon expected to be used within the liquid-immersed distribution transformer market, there may be considerable competition for amorphous ribbon that may hamper LVDT manufacturers' ability to develop experience with amorphous cores in the near-term, which would lead to considerable supply chain disruptions in the compliance year.

DOE notes that while the January 2023 NOPR proposed standards at TSL 5, distribution transformer shortages have persisted throughout 2023. DOE further notes that hundreds of millions of dollars in investments have been announced by distribution transformer manufacturers to add capacity to resolve the existing transformer shortages and those investments are currently undergoing the design, permitting, engineering, and construction process needed to begin production with scheduled completions typically targeting 24 to 36 months. DOE updated its analysis of conversion costs in this final rule based on stakeholder feedback and are the costs are now greater than the costs analyzed in the January 2023 NOPR. Investing in conversion costs, in addition to manufacturers investments to increase capacity, without offering flexibility for manufacturers to add amorphous capacity in an additive manner has led DOE to conclude that TSL 5 offers substantial risk that could extend current transformer shortages longer they otherwise would be.

The Secretary concludes that at TSL 5 for low-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the risks that manufacturers would not be able to scale up amorphous core production within the compliance period without significantly increasing distribution transformer lead times. The benefits of TSL 5 for low-voltage dry-type distribution transformers do not outweigh the risks of significant impacts to the distribution transformer supply chain, particularly when considered in conjunction with the expected demand for core materials in the liquid-immersed distribution transformer market. Consequently, the Secretary has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4. TSL 4 would save an estimated 2.38 quads of energy, an amount DOE considers significant. Under TSL 4, the NPV of consumer benefit would be $3.20 billion using a discount rate of 7 percent, and $10.14 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 43.56 Mt of CO_2, 10.4 thousand tons of SO_2, 77.9 thousand tons of NO_X, 0.1 tons of Hg, 362.3 thousand tons of CH_4, and 0.3 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 4 is $1.71 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 4 is $1.06 billion using a 7-percent discount rate and $3.38 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 4 is $5.97 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $15.23 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified.

At TSL 4, the average LCC impact ranges from $551 for equipment class 3 to $1,068 for equipment class 4. The median PBP ranges from 3.4 years for equipment class 4 to 7.4 years for equipment class 3. The fraction of consumers experiencing a net LCC cost ranges from 2 percent for equipment class 4 to 14 percent for equipment class 3.

At TSL 4, the projected change in INPV ranges from a decrease of $62.9 million to a decrease of $52.2 million, which corresponds to decreases of 29.7 percent and 24.7 percent, respectively. DOE estimates that industry must invest $86.7 million to comply with standards set at TSL 4.

The energy savings under TSL 4 are primarily achievable by using amorphous cores. As noted, LVDT manufacturers have little or no experience producing transformer designs with amorphous cores and little experience as to potential modifications that may need to be made to new protective equipment. DOE is concerned that given the large quantity of amorphous ribbon expected to be used within the liquid-immersed distribution transformer market, there may be considerable competition for amorphous ribbon that may hamper LVDT manufacturers' ability to develop experience with amorphous cores in the near-term, which would lead to considerable supply chain disruptions in the compliance year.

The Secretary concludes that at TSL 4 for low-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the risks that manufacturers would not be able to scale up amorphous core production within the compliance period without significantly increasing distribution transformer lead times. Further, as discussed in section IV.C.2.a of this document, an inability of suppliers of amorphous ribbon to scale production and manufacturers to retool production lines for amorphous cores within the compliance period could lead to market uncertainty and disruption during a critical time. Several stakeholders have noted that given existing supply challenges, a total conversion to amorphous is not feasible in the near term. While this final rule considers a longer compliance period, the impacts of shortages are substantial, which may have an impact on grid reliability. Therefore, the risks of scale-up and compliance taking slightly longer, due to any number of unforeseen challenges, could have substantial impacts. The benefits of TSL 4 for low-voltage dry-type distribution transformer do not outweigh the risks of significant impacts to the distribution transformer supply chain, particularly when considered in conjunction with the expected demand for core materials in the liquid-immersed distribution transformer market. Consequently, the Secretary has concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3. TSL 3 would save an estimated 1.71 quads of energy, an amount DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $2.08 billion using a discount rate of 7 percent, and $6.68 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 31.28 Mt of CO_2, 7.5 thousand tons of SO_2, 55.9 thousand tons of NO_X, 0.1 tons of Hg, 260.0 thousand tons of CH_4, and 0.2 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 3 is $1.23 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 3 is $0.76 billion using a 7-percent discount rate and $2.42 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 3 is $4.07 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 3 is $10.33 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a standard level is economically justified.

At TSL 3, the average LCC impact ranges from $321 for equipment class 3 to $765 for equipment class 4. The median PBP ranges from 3.6 years for equipment class 4 to 7.4 years for equipment class 3—well below the estimated average lifetime of 32 years. The fraction of consumers experiencing a net LCC cost ranges from 9 percent for equipment class 4 to 28 percent for equipment class 3.

At TSL 3, the projected change in INPV ranges from a decrease of $27.1 million to a decrease of $18.9 million, which corresponds to decreases of 12.8 percent and 8.9 percent, respectively. DOE estimates that industry must invest $36.1 million to comply with standards set at TSL 3.

After considering the analysis and weighing the benefits and burdens, the Secretary has concluded that a standard set at TSL 3 for low-voltage dry-type distribution transformers would be economically justified. Notably, the benefits to consumers outweigh the cost to manufacturers. At this TSL, the average LCC savings are positive across all equipment classes. An estimated 11 percent of low-voltage dry-type distribution transformer consumers experience a net cost. The FFC national energy savings are significant and the NPV of consumer benefits is positive using both a 3-percent and 7-percent discount rate. At TSL 3, the NPV of consumer benefits, even measured at the more conservative discount rate of 7 percent, is larger than the maximum estimated manufacturers' loss in INPV. The standard levels at TSL 3 are economically justified even without weighing the estimated monetary value of emissions reductions. When those emissions reductions are included—representing $1.23 billion in climate benefits (associated with the average SC–GHG at a 3-percent discount rate), and $2.42 billion (using a 3-percent discount rate) or $0.76 billion (using a 7-percent discount rate) in health benefits—the rationale becomes stronger still.

Notably, the energy savings under TSL 3 do not carry the same risks to distribution transformer supply chains as TSL 4 and TSL 5. The energy savings under TSL 3 are primarily achieved using lower-loss GOES cores with some shipments using amorphous cores where it is most cost-competitive. DOE notes that at TSL 3, both amorphous and GOES cores are cost-competitive with regard to which core steel produces the lowest first-cost unit, allowing manufacturers flexibility in establishing supply chains and redesigning transformers to meet amended standards based on their specific needs.

As stated, DOE conducts the walk-down analysis to determine the TSL that represents the maximum improvement in energy efficiency that is technologically feasible and economically justified as required under EPCA. The walk-down is not a comparative analysis, as a comparative analysis would result in the maximization of net benefits instead of energy savings that are technologically feasible and economically justified, which would be contrary to the statute. 86 FR 70892, 70908.

Although DOE has not conducted a comparative analysis to select the new energy conservation standards, DOE notes that TSL 3 has considerably lower manufacturer impacts than TSL 4 and TSL 5. Further, TSL 3 allows both GOES and amorphous cores to compete, ensuring a diverse supply of materials can serve the LVDT market.

Although DOE considered amended standard levels for distribution transformers by grouping the efficiency levels for each equipment category into TSLs, DOE evaluates all analyzed efficiency levels in its analysis. The TSLs constructed by DOE to examine the impacts of amended energy efficiency standards for low-voltage dry-type distribution transformers align with the corresponding ELs defined in the engineering analysis. For the ELs above baseline that compose TSL 3, DOE finds that LCC savings are positive for all equipment classes, with simple paybacks well below the average equipment lifetimes. DOE also finds that the estimated fraction of consumers who would be negatively impacted from a standard at TSL 3 to be 11 percent for all equipment classes. Importantly, DOE expects TSL 3 to be achievable with both amorphous and GOES core materials.

Therefore, based on the previous considerations, DOE adopts the energy conservation standards for LVDT distribution transformers at TSL 3. The amended energy conservation standards for distribution transformers, which are expressed as percentage efficiency at 35 percent PUL, are shown in Table V.60.

Table V.60 Amended Energy Conservation Standards for Low-Voltage Dry-Type Distribution Transformers

Single-Phase		Three-Phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
15	98.39%	15	98.31%
25	98.60%	30	98.58%
37.5	98.74%	45	98.72%
50	98.81%	75	98.88%
75	98.95%	112.5	98.99%
100	99.02%	150	99.06%
167	99.09%	225	99.15%
250	99.16%	300	99.22%
333	99.23%	500	99.31%
		750	99.38%
		1000	99.42%

3. Benefits and Burdens of TSLs Considered for Medium-Voltage Dry-Type Distribution Transformer Standards

Table V.61 and Table V.62 summarize the quantitative impacts estimated for each TSL for medium-voltage dry-type distribution transformers. The national impacts are measured over the lifetime of distribution transformers purchased in the 30-year period that begins in the anticipated year of compliance with amended standards (2029–2058). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. DOE is presenting monetized benefits of GHG emissions reductions in accordance with the applicable Executive Orders, and DOE would reach the same conclusion presented in this notice in the absence of the social cost of greenhouse gases, including the Interim Estimates presented by the Interagency Working Group. The efficiency levels contained in each TSL are described in section V.A of this document.

Table V.61 Summary of Analytical Results for Medium-Voltage Dry-Type Distribution Transformer TSLs: National Impacts (for Units Shipped between 2029 – 2058)

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Cumulative FFC National Energy Savings					
Quads	0.10	**0.14**	0.42	0.55	0.65
Cumulative FFC Emissions Reduction					
CO_2 (*million metric tons*)	1.86	**2.59**	7.55	9.85	11.72
CH_4 (*thousand tons*)	15.60	**21.86**	63.48	82.90	98.65
N_2O (*thousand tons*)	0.01	**0.02**	0.06	0.08	0.09
NO_X (*thousand tons*)	3.35	**4.69**	13.62	17.79	21.17
SO_2 (*thousand tons*)	0.45	**0.63**	1.82	2.37	2.82
Hg (*tons*)	0.00	**0.00**	0.01	0.02	0.02
Present Value of Benefits and Costs *(7% discount rate, billion 2022$)*					
Consumer Operating Cost Savings	0.11	**0.15**	0.66	0.78	0.84
Climate Benefits*	0.07	**0.10**	0.30	0.39	0.46
Health Benefits**	0.05	**0.06**	0.19	0.24	0.29
Total Benefits†	0.23	**0.32**	1.14	1.41	1.59
Consumer Incremental Product Costs‡	-0.02	**0.12**	0.41	0.60	0.92
Consumer Net Benefits	0.13	**0.03**	0.25	0.18	-0.08
Total Net Benefits	0.25	**0.20**	0.73	0.81	0.67
Present Value of Benefits and Costs (*3% discount rate, billion 2022$*)					
Consumer Operating Cost Savings	0.32	**0.44**	1.91	2.26	2.44
Climate Benefits*	0.07	**0.10**	0.30	0.39	0.46
Health Benefits**	0.14	**0.20**	0.59	0.77	0.92
Total Benefits†	0.54	**0.74**	2.80	3.41	3.82
Consumer Incremental Product Costs‡	-0.03	**0.22**	0.76	1.12	1.72
Consumer Net Benefits	0.35	**0.22**	1.15	1.14	0.72
Total Net Benefits	0.57	**0.52**	2.04	2.30	2.10

Note: This table presents the costs and benefits associated with distribution transformers shipped during the period 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped during the period 2029−2058.

* Climate benefits are calculated using four different estimates of the SC-CO_2, SC-CH_4 and SC-N_2O. Together, these represent the global SC-GHG. For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for NO_X and SO_2) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

Table V.62 Summary of Analytical Results for Medium-Voltage Dry-Type Distribution Transformer TSLs: Manufacturer and Consumer Impacts (for Units Shipped between 2029 – 2058)

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Manufacturer Impacts					
Industry NPV (million 2022$) (No-new-standards case INPV = 95)	92	91 to 93	69 to 76	66 to 76	62 to 79
Industry NPV (% change)	(3.6) to (2.8)	(4.7) to (2.5)	(27.8) to (20.1)	(31.0) to (19.5)	(34.9) to (17.1)
Consumer Average LCC Savings (2022$)					
EC 6	1,597	1,389	998	478	136
EC 8	6,420	3,794	3,418	2,882	-2,084
EC 10	1,823	-1,438	-2,788	-2,569	-6,239
Shipment-Weighted Average*	4,260	1,738	1,036	754	-3,178
Consumer Simple PBP (years)					
EC 6	0.7	3.3	10.6	14.8	15.0
EC 8	Instant	1.6	11.0	12.7	17.3
EC 10	6.2	20.1	19.9	18.5	20.9
Shipment-Weighted Average*	Instant	8.0	13.9	14.9	18.2
Percent of Consumers that Experience a Net Cost					
EC 6	6	10	35	50	47
EC 8	3	11	29	29	64
EC 10	19	77	63	67	85
Shipment-Weighted Average*	8	33	41	45	68

DOE first considered TSL 5. TSL 5 would save an estimated 0.65 quads of energy, an amount DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $-0.08 billion using a discount rate of 7 percent, and $0.72 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 11.72 Mt of CO_2, 2.8 thousand tons of SO_2, 21.2 thousand tons of NO_X, 0.02 tons of Hg, 98.6 thousand tons of CH_4, and 0.1 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 5 is $0.46 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 5 is $0.29 billion using a 7-percent discount rate and $0.92 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 5 is $0.67 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 5 is $2.10 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a standard level is economically justified.

At TSL 5, the average LCC impact ranges from $-6,239 for equipment class 10 to $136 for equipment class 6. The median PBP ranges from 5.0 years for equipment class 6 to 10.5 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 47 percent for equipment class 6 to 85 percent for equipment class 10.

At TSL 5, the projected change in INPV ranges from a decrease of $33.2 million to a decrease of $16.3 million, which corresponds to decreases of 34.9 percent and 17.1 percent, respectively. DOE estimates that industry must invest $36.2 million to comply with standards set at TSL 5.

The Secretary concludes that at TSL 5 for medium-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on many consumers as indicated by the negative LCCs for many equipment classes, the percentage of customers who would experience LCC increases, and the capital and engineering costs that could result in a reduction in INPV for manufacturers. At TSL 5 DOE is estimating negative benefits for a disproportionate fraction of consumers—a shipment weighted average of 68 percent. Further DOE estimates that there is a substantial risk to consumers, with a shipment weighted LCC savings for all MVDT equipment of -$3,178. Consequently, the Secretary has concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4. TSL 4 would save an estimated 0.55 quads of energy, an amount DOE considers significant. Under TSL 4, the NPV of consumer benefit would be $0.18 billion using a discount rate of 7 percent, and $1.14 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 9.85 Mt of CO_2, 2.4 thousand tons of SO_2, 17.8 thousand tons of NO_X, 0.02 tons of Hg, 82.9 thousand tons of CH_4, and 0.1 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 4 is $0.39 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 4 is $0.24 billion using a 7-percent discount rate and $0.77 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 4 is $0.81 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $2.30 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified.

At TSL 4, the average LCC impact ranges from $-2,569 for equipment class 10 to $2,882 for equipment class 8. The median PBP ranges from 4.2 years for equipment class 8 to 9.2 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 29 percent for equipment class 8 to 67 percent for equipment class 10.

At TSL 4, the projected change in INPV ranges from a decrease of $29.5 million to a decrease of $18.6 million, which corresponds to decreases of 31.0 percent and 19.5 percent, respectively. DOE estimates that industry must invest $34.8 million to comply with standards set at TSL 4.

The Secretary concludes that at TSL 4 for medium-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on many consumers as indicated by the negative LCCs for many equipment classes, the percentage of customers who would experience LCC increases, and the capital and engineering costs that could result in a reduction in INPV for manufacturers. At TSL 4 DOE is estimating negative benefits for a disproportionate fraction of consumers—a shipment weighted average of 45 percent. Consequently, the Secretary has concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3. TSL 3 would save an estimated 0.42 quads of energy, an amount DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $0.25 billion using a discount rate of 7 percent, and $1.15 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 7.55 Mt of CO_2, 1.8 thousand tons of SO_2, 13.6 thousand tons of NO_X, 0.01 tons of Hg, 63.5 thousand tons of CH_4, and 0.1 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 3 is $0.30 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 3 is $0.19 billion using a 7-percent discount rate and $0.59 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 3 is $0.73 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 3 is $2.04 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified. At TSL 3, the average LCC impact ranges from $-2,788 for equipment class 10 to $3,418 for equipment class 8. The median PBP ranges from 3.5 years for equipment class 6 to 10.0 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 29 percent for equipment class 8 to 63 percent for equipment class 10.

At TSL 3, the projected change in INPV ranges from a decrease of $26.4 million to a decrease of $19.1 million, which corresponds to decreases of 27.8 percent and 20.1 percent, respectively. DOE estimates that industry must invest $32.7 million to comply with standards set at TSL 3.

The Secretary concludes that at TSL 3 for medium-voltage dry-type distribution transformers, the benefits of energy savings, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on many consumers as indicated by the negative LCCs for many equipment classes, the percentage of customers who would experience LCC increases, and the capital and engineering costs that could result in a reduction in INPV for manufacturers. At TSL 3, DOE estimates negative benefits for a disproportionate fraction of consumers—a shipment weighted average of 41 percent. Consequently, the Secretary has concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2. TSL 2 would save an estimated 0.14 quads of energy, an amount DOE considers significant. Under TSL 2, the NPV of consumer benefit would be $0.03 billion using a discount rate of 7 percent, and $0.22 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 2 are 2.59 Mt of CO_2, 0.6 thousand tons of SO_2, 4.7 thousand tons of NO_X, 0.0 tons of Hg, 21.9 thousand tons of CH_4, and 0.0 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 2 is $0.10 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 2 is $0.06 billion using a 7-percent discount rate and $0.20 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 2 is $0.20 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 2 is $0.52 billion. The estimated total NPV is provided for additional information, however DOE primarily relies upon the NPV of consumer benefits when determining whether a proposed standard level is economically justified.

At TSL 2, the average LCC impact ranges from $−1,438 for equipment class 10 to $3,794 for equipment class 8. The median PBP ranges from 0.5 years for equipment class 8 to 10.1 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 10 percent for equipment class 6 to 77 percent for equipment class 10.

At TSL 2, the projected change in INPV ranges from a decrease of $4.4 million to a decrease of $2.3 million, which corresponds to decreases of 4.7 percent and 2.5 percent, respectively. DOE estimates that industry must invest

$5.7 million to comply with standards set at TSL 2.

After considering the analysis and weighing the benefits and burdens, the Secretary has concluded that at a standard set at TSL 2 for medium-voltage distribution transformers would be economically justified. At this TSL, the average LCC savings are positive across all equipment classes except for equipment class 10, with a shipment weighed average LCC for all medium-voltage dry-type distribution transformers of $1,738. An estimated 10 percent of equipment class 6 to 77 percent of equipment class 10 medium-voltage dry-type distribution transformer consumers experience a net cost, while the shipment weighted average of consumers who experience a net cost is 33 percent. The FFC national energy savings are significant and the NPV of consumer benefits is positive using both a 3-percent and 7-percent discount rate. Notably, the benefits to consumers outweigh the cost to manufacturers. At TSL 2, the NPV of consumer benefits, even measured at the more conservative discount rate of 7 percent is over 6 times higher than the maximum estimated manufacturers' loss in INPV. The standard levels at TSL 2 are economically justified even without weighing the estimated monetary value of emissions reductions. When those emissions reductions are included—representing $0.10 billion in climate benefits (associated with the average SC–GHG at a 3-percent discount rate), and $0.20 billion (using a 3-percent discount rate) or $0.06 billion (using a 7-percent discount rate) in health benefits—the rationale becomes stronger still.

As stated, DOE conducts the walk-down analysis to determine the TSL that represents the maximum improvement in energy efficiency that is technologically feasible and economically justified as required under EPCA. The walk-down is not a comparative analysis, as a comparative analysis would result in the maximization of net benefits instead of energy savings that are technologically feasible and economically justified, which would be contrary to the statute. 86 FR 70892, 70908.

Although DOE considered amended standard levels for distribution transformers by grouping the efficiency levels for each equipment category into TSLs, DOE evaluates all analyzed efficiency levels in its analysis. For medium-voltage dry-type distribution transformer the TSL 2 maps directly to EL 2 for all equipment classes. EL 2 represents a 10 percent reduction in losses over the current standard. While the consumer benefits for equipment class 10 are negative at EL 2 at -$1,438, they are positive for all other equipment representing 67 percent of all MVDT units shipped, additionally the consumer benefits at EL 2, excluding equipment class 10, increases from $1,738 to $2,217 in LCC savings Further, the EL 2 represent an improvement in efficiency where the FFC national energy savings is maximized, with positive NPVs at both 3 and 7 percent, and the shipment weighted average consumer benefit at EL 2 is positive. The shipment weighted consumer benefits for TSL, and EL 2 are shown in Table V.63.

As discussed previously, at the max-tech efficiency levels (TSL 5), TSL 4, and TSL 3 for all medium-voltage dry-type distribution transformers there is a substantial risk to consumers due to negative LCC savings for some equipment, with a shipment weighted average consumer benefit of -$3,178, $754, and $1,036, respectively, while at TSL 2 it is $1,738. Therefore, DOE has concluded that the efficiency levels above TSL 2 are not justified. Additionally, at the examined efficiency levels greater than TSL 2 DOE is estimating that a disproportionate fraction of consumers would be negatively impacted by these efficiency levels. DOE estimates that shipment weighted fraction of negatively impacted consumers for TSL 3, TSL 4, and TSL 5 (max-tech) to be 68, 45, and 41 percent, respectively.

Therefore, based on the previous considerations, DOE adopts the energy conservation standards for distribution transformers at TSL 2. The amended energy conservation standards for MVDT distribution transformers, which are expressed as percentage efficiency at 50 percent PUL, are shown in Table V.63.

Table V.63 Amended Energy Conservation Standards for Medium-Voltage Dry-Type Distribution Transformers

Single-Phase				Three-Phase			
	BIL*				BIL		
	20-45 kV	46-95 kV	≥96 kV		20-45 kV	46-95 kV	≥96 kV
kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)	kVA	Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.29%	98.07%		15	97.75%	97.46%	
25	98.50%	98.31%		30	98.11%	97.87%	
37.5	98.64%	98.47%		45	98.29%	98.07%	
50	98.74%	98.58%		75	98.50%	98.32%	
75	98.86%	98.71%	98.68%	112.5	98.67%	98.52%	
100	98.94%	98.80%	98.77%	150	98.79%	98.66%	
167	99.06%	98.95%	98.92%	225	98.94%	98.82%	98.71%
250	99.16%	99.06%	99.02%	300	99.04%	98.93%	98.82%
333	99.23%	99.13%	99.09%	500	99.18%	99.09%	99.00%
500	99.30%	99.21%	99.18%	750	99.29%	99.21%	99.12%
667	99.34%	99.26%	99.24%	1000	99.35%	99.28%	99.20%
833	99.38%	99.31%	99.28%	1500	99.43%	99.37%	99.29%
				2000	99.49%	99.42%	99.35%
				2500	99.52%	99.47%	99.40%
				3750	99.50%	99.44%	99.40%
				5000	99.48%	99.43%	99.39%

*BIL means basic impulse insulation level.

4. Annualized Benefits and Costs of the Adopted Standards for Liquid-Immersed Distribution Transformers

The benefits and costs of the adopted standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2022$) of the benefits from operating products that meet the adopted standards (consisting primarily of operating cost savings from using less energy), minus increases in product purchase costs, and (2) the annualized monetary value of the climate and health benefits.

Table V.64 shows the annualized values for liquid-immersed distribution transformers under TSL 3, expressed in 2022$. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NOx and SO_2 reductions, and the 3-percent discount rate case for GHG social costs, the estimated cost of the adopted standards for liquid-immersed distribution transformers is $151.1 million per year in increased equipment installed costs, while the estimated annual benefits are $210.2 million from reduced equipment operating costs, $106.1 million in GHG reductions, and $117.0 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $282.3 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the adopted standards for liquid-immersed distribution transformers is $152.6 million per year in increased equipment costs, while the estimated annual benefits are $348.3 million in reduced operating costs, $106.1 million from GHG reductions, and $213.2 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $515.1 million per year.

Table V.64 Annualized Benefits and Costs of Adopted Energy Conservation Standards (TSL 3) for Liquid-immersed Distribution Transformers (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	348.3	329.0	407.3
Climate Benefits*	106.1	103.7	119.9
Health Benefits**	213.2	208.1	241.9
Total Benefits†	667.6	640.8	769.2
Consumer Incremental Equipment Costs‡	152.6	194.5	156.5
Net Benefits†	515.1	446.2	612.7
Change in Producer Cash Flow (INPV)‡‡	(11.7) – (8.9)	(11.7) – (8.9)	(11.7) – (8.9)
7% discount rate			
Consumer Operating Cost Savings	210.2	199.6	242.5
Climate Benefits* (3% discount rate)	106.1	103.7	119.9
Health Benefits**	117.0	114.6	131.0
Total Benefits†	433.4	417.9	493.5
Consumer Incremental Equipment Costs‡	151.1	186.5	155.1
Net Benefits†	282.3	231.4	338.4
Change in Producer Cash Flow (INPV)‡‡	(11.7) – (8.9)	(11.7) – (8.9)	(11.7) – (8.9)

Note: This table presents the costs and benefits associated with equipment shipped in 2029–2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029–2058. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the *AEO2023* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a constant rate in the Primary Estimate, an increase in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in section IV.F.1 of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For liquid-immersed distribution transformers, the annualized change in INPV ranges from -$11.7 million to -$8.9 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $709.5 million to $712.3 million at a 3-percent discount rate and would range from $476.6 million to $479.4 million at a 7-percent discount rate. Parentheses () indicate negative values.

5. Annualized Benefits and Costs of the Adopted Standards for Low-Voltage Dry-Type Distribution Transformers

The benefits and costs of the adopted standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2022$) of the benefits from operating products that meet the adopted standards (consisting primarily of operating cost savings from using less energy), minus increases in product purchase costs, and (2) the annualized monetary value of the climate and health benefits.

Table V.65 shows the annualized values for low-voltage dry-type under TSL 3, expressed in 2022$. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NOx and SO_2 reductions, and the 3-percent discount rate case for GHG social costs, the estimated cost of the adopted standards for low-voltage dry-type is $66.6 million per year in increased equipment installed costs, while the estimated annual benefits are $286.8 million from reduced equipment operating costs, $70.4 million in GHG reductions, and $80.3 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $370.8 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the adopted standards for low-voltage dry-type is $67.4 million per year in increased equipment costs, while the estimated annual benefits are $450.9 million in reduced operating costs, $70.4 million from GHG reductions, and $139.1 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $593.0 million per year.

Table V.65 Annualized Benefits and Costs of Adopted Energy Conservation Standards (TSL 3) for Low-voltage Dry-type Distribution Transformers (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	450.9	434.3	463.1
Climate Benefits*	70.4	70.4	70.4
Health Benefits**	139.1	139.1	139.1
Total Benefits†	660.4	643.8	672.6
Consumer Incremental Equipment Costs‡	67.4	89.4	60.6
Net Benefits†	593.0	554.4	612.0
Change in Producer Cash Flow (INPV)‡‡	(3.1) – (2.2)	(3.1) – (2.2)	(3.1) – (2.2)
7% discount rate			
Consumer Operating Cost Savings	286.8	276.8	294.6
Climate Benefits* (3% discount rate)	70.4	80.3	80.3
Health Benefits**	80.3	70.4	70.4
Total Benefits†	437.4	427.5	445.3
Consumer Incremental Equipment Costs‡	66.6	85.1	60.8
Net Benefits†	370.8	342.4	384.5
Change in Producer Cash Flow (INPV)‡‡	(3.1) – (2.2)	(3.1) – (2.2)	(3.1) – (2.2)

Note: This table presents the costs and benefits associated with equipment shipped in 2029−2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029−2058. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the *AEO2023* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a constant rate in the Primary Estimate, an increase in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in sections IV.F.1 of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 11.1 percent that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For LVDT distribution transformers, the annualized change in INPV ranges from -$3.1 million to $2.2 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $589.9 million to $590.8 million at a 3-percent discount rate and would range from $367.7 million to $368.6 million at a 7-percent discount rate. Parentheses () indicate negative values.

6. Annualized Benefits and Costs of the Adopted Standards for Medium-Voltage Dry-Type Distribution Transformers

The benefits and costs of the adopted standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2022$) of the benefits from operating products that meet the adopted standards (consisting primarily of operating cost savings from using less energy), minus increases in product purchase costs, and (2) the annualized monetary value of the climate and health benefits.

Table V.66 shows the annualized values for medium-voltage dry-type under TSL 2, expressed in 2022$. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and NOx and SO_2 reductions, and the 3-percent discount rate case for GHG social costs, the estimated cost of the adopted standards for medium-voltage dry-type is $12.5 million per year in increased equipment installed costs, while the estimated annual benefits are $15.9 million from reduced equipment operating costs, $5.9 million in GHG reductions, and $6.7 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $16.0 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the adopted standards for medium-voltage dry-type is $12.7 million per year in increased equipment costs, while the estimated annual benefits are $25.1 million in reduced operating costs, $5.9 million from GHG reductions, and $11.7 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $29.9 million per year.

Table V.66 Annualized Benefits and Costs of Adopted Energy Conservation Standards (TSL 2) for Medium-voltage Dry-type Distribution Transformers (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	25.1	24.1	25.8
Climate Benefits*	5.9	5.9	5.9
Health Benefits**	11.7	11.7	11.7
Total Benefits†	42.6	41.6	43.3
Consumer Incremental Equipment Costs‡	12.7	17.1	11.3
Net Benefits†	29.9	24.5	32.0
Change in Producer Cash Flow (INPV)‡‡	(0.4) – (0.2)	(0.4) – (0.2)	(0.4) – (0.2)
7% discount rate			
Consumer Operating Cost Savings	15.9	15.4	16.4
Climate Benefits* (3% discount rate)	5.9	6.7	6.7
Health Benefits**	6.7	5.9	5.9
Total Benefits†	28.5	28.0	29.0
Consumer Incremental Equipment Costs‡	12.5	16.3	11.3
Net Benefits†	16.0	11.7	17.6
Change in Producer Cash Flow (INPV)‡‡	(0.4) – (0.2)	(0.4) – (0.2)	(0.4) – (0.2)

Note: This table presents the costs and benefits associated with equipment shipped in 2029–2058. These results include consumer, climate, and health benefits that accrue after 2058 from the products shipped in 2029–2058. The Primary, Low Net Benefits, and High Net Benefits Estimates utilize projections of energy prices from the *AEO2023* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental equipment costs reflect a constant rate in the Primary Estimate, an increase in the Low Net Benefits Estimate, and a high decline rate in the High Net Benefits Estimate. The methods used to derive projected price trends are explained in section IV.F.1 of this document. Note that the Benefits and Costs may not sum to the Net Benefits due to rounding.

* Climate benefits are calculated using four different estimates of the global SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3-percent discount rate are shown; however, DOE emphasizes the importance and value of considering the benefits calculated using all four sets of SC-GHG estimates. To monetize the benefits of reducing GHG emissions, this analysis uses the interim estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990* published in February 2021 by the IWG.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. *See* section IV.L of this document for more details.

† Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with a 3-percent discount rate.

‡ Costs include incremental equipment costs as well as installation costs.

reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.
† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates. See Table V.55 for net benefits using all four SC-GHG estimates.
‡ Costs include incremental equipment costs as well as installation costs.
‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. Change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent, 11.1 percent, and 9.0 percent for liquid-immersed, LVDT, and MVDT distribution transformers respectively that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For distribution transformers, the change in INPV ranges from -$176.5 million to -$132.2 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the net benefit calculation for this final rule, the net benefits would range from $8.39 billion to $8.44 billion at a 3-percent discount rate and would range from $21.47 billion to $21.52 billion at a 7-percent discount rate.
Parentheses () indicate negative values.

7. Benefits and Costs of the Proposed Standards for All Considered Distribution Transformers

As described in sections V.C.1 through V.C.3, for this final rule DOE is adopting TSL 3 for liquid-immersed, TSL 3 for low-voltage dry-type, and TSL 2 for medium-voltage dry-type distribution transformers. Table V.67 shows the combined cumulative benefits, and Table V.68 shows the combined annualized benefits for the proposed levels for all distribution transformers.

Table V.67 Summary of Monetized Benefits and Costs of Adopted Energy Conservation Standards for all Distribution Transformers at the Adopted Standard Levels (for Units Shipped between 2029 – 2058)

	Billion $2022
3% discount rate	
Consumer Operating Cost Savings	14.36
Climate Benefits*	3.18
Health Benefits**	6.33
Total Benefits†	23.87
Consumer Incremental Product Costs‡	4.05
Net Benefits†	19.82
Change in Producer Cash Flow (INPV)‡‡	(0.18) – (0.13)
7% discount rate	
Consumer Operating Cost Savings	4.85
Climate Benefits* (3% discount rate)	3.18
Health Benefits**	1.93
Total Benefits†	9.96
Consumer Incremental Product Costs‡	2.18
Net Benefits†	7.78
Change in Producer Cash Flow (INPV)‡‡	(0.18) – (0.13)

Note: This table presents the costs and benefits associated with distribution transformers shipped in 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO_2), methane (SC-CH_4), and nitrous oxide (SC-N_2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate) (see section IV.L of this document). Together these represent the global social cost of greenhouse gases (SC-GHG). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate. See section. IV.L of this document for more details. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22-30087) granted the Federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana v. Biden*, No. 21-cv-1074-JDC-KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the Federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from "adopting, employing, treating as binding, or relying upon" the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from

reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.
† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates. See Table V.55 for net benefits using all four SC-GHG estimates.
‡ Costs include incremental equipment costs as well as installation costs.
‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. Change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent, 11.1 percent, and 9.0 percent for liquid-immersed, LVDT, and MVDT distribution transformers respectively that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For distribution transformers, the change in INPV ranges from -$176.5 million to -$132.2 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the net benefit calculation for this final rule, the net benefits would range from $8.39 billion to $8.44 billion at a 3-percent discount rate and would range from $21.47 billion to $21.52 billion at a 7-percent discount rate.
Parentheses () indicate negative values.

Table V.68 Annualized Benefits and Costs of Adopted Energy Conservation Standards for all Distribution Transformers at Adopted Standard Levels (for Units Shipped between 2029 – 2058)

Category	Million 2022$/year		
	Primary Estimate	Low-Net-Benefits Estimate	High-Net-Benefits Estimate
3% discount rate			
Consumer Operating Cost Savings	824.3	787.5	896.2
Climate Benefits*	182.4	179.9	196.2
Health Benefits**	364.0	358.8	392.7
Total Benefits†	1,370.6	1,326.2	1,485.1
Consumer Incremental Product Costs‡	232.6	301.1	228.4
Net Benefits†	1,138.0	1,025.1	1,256.7
Change in Producer Cash Flow (INPV)‡‡	(15.2) – (11.3)	(15.2) – (11.3)	(15.2) – (11.3)
7% discount rate			
Consumer Operating Cost Savings	512.9	491.8	553.5
Climate Benefits* (3% discount rate)	182.4	179.9	196.2
Health Benefits**	204.1	201.6	218.1
Total Benefits†	899.4	873.3	967.7
Consumer Incremental Product Costs‡	230.3	287.8	227.2
Net Benefits†	669.1	585.5	740.6
Change in Producer Cash Flow (INPV)‡‡	(15.2) – (11.3)	(15.2) – (11.3)	(15.2) – (11.3)

Note: This table presents the costs and benefits associated with distribution transformers shipped in 2029−2058. These results include benefits to consumers which accrue after 2058 from the products shipped in 2029−2058.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC-CO_2), methane (SC-CH_4), and nitrous oxide (SC-N_2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate) (see section IV.L of this document). Together these represent the global social cost of greenhouse gases (SC-GHG). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate. See section. IV.L of this document for more details. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22-30087) granted the Federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana v. Biden*, No. 21-cv-1074-JDC-KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the Federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from "adopting, employing, treating as binding, or relying upon" the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. The benefits are based on the low estimates of the monetized value. DOE is currently only monetizing (for SO_x and NO_x) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates. See Table V.55 for net benefits using all four SC-GHG estimates.

‡ Costs include incremental equipment costs as well as installation costs.

‡‡ Operating Cost Savings are calculated based on the life-cycle cost analysis and national impact analysis as discussed in detail below. *See* sections IV.F and IV.H of this document. DOE's national impact analysis includes all impacts (both costs and benefits) along the distribution chain beginning with the increased costs to the manufacturer to manufacture the equipment and ending with the increase in price experienced by the customer. DOE also separately conducts a detailed analysis on the impacts on manufacturers (*i.e.*, manufacturer impact analysis, or "MIA"). *See* section IV.J of this document. In the detailed MIA, DOE models manufacturers' pricing decisions based on assumptions regarding investments, conversion costs, cash flow, and margins. The MIA produces a range of impacts, which is the rule's expected impact on the INPV. The change in INPV is the present value of all changes in industry cash flow, including changes in production costs, capital expenditures, and manufacturer profit margins. The annualized change in INPV is calculated using the industry weighted average cost of capital value of 7.4 percent, 11.1 percent, and 9.0 percent for liquid-immersed, LVDT, and MVDT distribution transformers respectively that is estimated in the manufacturer impact analysis (*see* chapter 12 of the final rule TSD for a complete description of the industry weighted average cost of capital). For distribution transformers, the annualized change in INPV ranges from -$15.2 million to -$11.3 million. DOE accounts for that range of likely impacts in analyzing whether a trial standard level is economically justified. *See* section V.C of this document. DOE is presenting the range of impacts to the INPV under two markup scenarios: the Preservation of Gross Margin scenario, which is the manufacturer markup scenario used in the calculation of Consumer Operating Cost Savings in this table; and the Preservation of Operating Profit scenario, where DOE assumed manufacturers would not be able to increase per-unit operating profit in proportion to increases in manufacturer production costs. DOE includes the range of estimated annualized change in INPV in the above table, drawing on the MIA explained further in section IV.J of this document to provide additional context for assessing the estimated impacts of this final rule to society, including potential changes in production and consumption, which is consistent with OMB's Circular A-4 and E.O. 12866. If DOE were to include the INPV into the annualized net benefit calculation for this final rule, the annualized net benefits would range from $1,187.3 million to $1,191.2 million at a 3-percent discount rate and would range from $694.0 million to $697.9 million at a 7-percent discount rate. Parentheses () indicate negative values.

8. Severability

Finally, DOE added a new paragraph (e) to 10 CFR 431.196 to provide that each energy conservation standard for each distribution transformer category (liquid immersed, LVDT, MDVT) is separate and severable from one another, and that if any energy conservation standard for any category is stayed or determined to be invalid by a court of competent jurisdiction, the remaining energy conservation standards for the other categories shall continue in effect. This severability clause is intended to clearly express the Department's intent that should an energy conservation standard for any category be stayed or invalidated, energy conservation standards for the other categories shall continue to remain in full force and legal effect.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Orders 12866, 13563, and 14094

Executive Order (E.O.) 12866, ''Regulatory Planning and Review,'' as supplemented and reaffirmed by E.O. 13563, ''Improving Regulation and Regulatory Review,'' 76 FR 3821 (Jan. 21, 2011) and amended by E.O. 14094, ''Modernizing Regulatory Review,'' 88 FR 21879 (April 11, 2023), requires agencies, to the extent permitted by law, 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 E.O. 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 (OIRA) in the Office of Management and Budget (OMB) 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, this final regulatory action is consistent with these principles.

Section 6(a) of E.O. 12866 also requires agencies to submit ''significant regulatory actions'' to OIRA for review. OIRA has determined that this final regulatory action constitutes a ''significant regulatory action'' within the scope of section 3(f)(1) of E.O. 12866. Accordingly, pursuant to section 6(a)(3)(C) of E.O. 12866, DOE has provided to OIRA an assessment, including the underlying analysis, of benefits and costs anticipated from the final regulatory action, together with, to the extent feasible, a quantification of those costs; and an assessment, including the underlying analysis, of costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation, and an explanation why the planned regulatory action is preferable to the identified potential alternatives. These assessments are summarized in this preamble and further detail can be found in the technical support document for this rulemaking.

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) and a final regulatory flexibility analysis (FRFA) for any rule that by law must be proposed for public comment, 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 E.O. 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (Aug. 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 website (*www.energy.gov/gc/office-general-counsel*). DOE has prepared the following FRFA for the products that are the subject of this rulemaking.

For manufacturers of distribution transformers, the 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. (See 13 CFR part 121.) The size standards are listed by NAICS code and industry description and are available at *www.sba.gov/document/support-table-size-standards*. Manufacturing of distribution transformers is classified under NAICS 335311, ''Power, Distribution, and Specialty Transformer Manufacturing''. The SBA sets a threshold of 800 employees or fewer for an entity to be considered as a small business for this category.

1. Need for, and Objectives of, Rule

EPCA authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. Title III, Part B of EPCA established the Energy Conservation Program for Consumer Products Other Than Automobiles. (42 U.S.C. 6291–6309) Title III, Part C of EPCA, added by Public Law 95–619, Title IV, section 411(a), established the Energy Conservation Program for Certain Industrial Equipment. The Energy Policy Act of 1992, Public Law 102–486, amended EPCA and directed DOE 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, Public Law 109–58, amended EPCA to establish energy conservation standards for low-voltage dry-type distribution transformers. (42 U.S.C. 6295(y))

EPCA further provides that, not later than six years after the issuance of any final rule establishing or amending a standard, DOE must publish either a notice of determination that standards for the product do not need to be amended, or a NOPR including new proposed energy conservation standards (proceeding to a final rule, as appropriate). (42 U.S.C. 6316(a); 42 U.S.C. 6295(m)(1))

DOE must follow specific statutory criteria for prescribing new or amended standards for covered equipment, including distribution transformers. Any new or amended standard for a covered product must 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. 6316(a); 42 U.S.C. 6295(o)(2)(A)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3))

2. Significant Issues Raised by Public Comments in Response to the IRFA

APPA commented that some small manufacturers will not be able to retool in sufficient time and will further worsen supply chain concerns. (APPA, No. 103 at p. 6) Powersmiths commented that using amorphous steel for LVDT distribution transformers requires an overhaul of the manufacturing production process. (Powersmiths, No. 112 at p. 6) Powersmiths commented that small manufacturers may not be able to make this transition due to the complexity and novelty of amorphous steel, along with the need for qualified designers, significant retooling costs, new manufacturing processes, and other additional resources. (*Id.*) Additionally, Powersmiths commented that even if LVDT small manufacturers could make this transition to amorphous steel they will need more than the 3-year compliance period proposed in the January 2023 NOPR. (*Id.*)

DOE understands that distribution transformer manufacturers, including small businesses, will incur conversion costs, which include retooling production facilities, in order to comply with standards. DOE estimates the impacts to the distribution transformer industry at each TSL in section V.B.2.a of this document and specifically estimates the impact to small businesses as part of this FRFA. Additionally, in the January 2023 NOPR DOE proposed a 3-year compliance period for manufacturers to meet the proposed standards. DOE is adopting a 5-year compliance period for this final rule. This additional time should allow for manufacturers, including small manufacturers, to retool their production facilities and make the necessary equipment additions that manufacturers will have to make to manufacture compliant distribution transformers. DOE also notes that the expanded compliance date provides greater time for core steel manufacturers, both GOES and amorphous, to meet expected demand.

NAHB commented that most home builders are considered a small business based on SBA's small business definition and expressed concern that DOE has not considered these home builders and other small businesses that rely on a consistent supply of distribution transformers that might be impacted by this rulemaking. (NAHB, No. 106 at p. 5) As stated in section IV.A.5 of this document, DOE notes that the standards amended in this rule will allow distribution transformers to cost-competitively utilize existing GOES capacity across many kVA ratings. Additionally, DOE notes that the compliance period for amended standards has been extended, from the 3-year compliance period proposed in the January 2023 NOPR to a 5-year compliance period adopted in this final rule. The additional time provided to redesign distribution transformers and build capacity will further mitigate any risk of disrupting production to meet current demand. Additionally, as stated in section V.B.2.c of this document, DOE does not anticipate that there will be a significant disruption in the supply of distribution transformers due to the adopted standards to home builders or any other distribution transformer markets.

3. Description and Estimated Number of Small Entities Affected

DOE conducted a more focused inquiry of the companies that could be small businesses that manufacture distribution transformers covered by this rulemaking. DOE used publicly available information to identify potential small businesses. DOE's research involved industry trade association membership directories (including NEMA),[202] DOE's publicly available Compliance Certification Database [203] (CCD), California Energy Commission's Modernized Appliance Efficiency Database System [204] (MAEDBS) to create a list of companies that manufacture or sell distribution transformers covered by this rulemaking. DOE also asked stakeholders and industry representatives if they were aware of any other small businesses during manufacturer interviews. DOE contacted select companies on its list, as necessary, to determine whether they met the SBA's definition of a small business that manufacturers distribution transformers covered by this rulemaking. DOE screened out companies that did not offer products covered by this rulemaking, did not meet the definition of a "small business," or are foreign owned and operated.

DOE's analysis identified 36 companies that sell or manufacture distribution transformers coved by this rulemaking in the U.S. market. At least two of these companies are not the original equipment manufacturers (OEM) and instead privately label distribution transformers that are manufactured by another distribution transformer manufacturer. Of the 34 companies that are OEMs, DOE identified nine companies that have fewer than 800 total employees and are not entirely foreign owned and operated. There are three small businesses that manufacture liquid-immersed distribution transformers; there are three small businesses that manufacture LVDT and MVDT distribution transformers; and there are three small businesses that only manufacture LVDT distribution transformers.[205]

Liquid-Immersed Distribution Transformer Small Businesses

Liquid-immersed distribution transformers account for over 80 percent of all distribution transformer shipments covered by this rulemaking. Seven major manufacturers supply more than 80 percent of the market for liquid-immersed distribution transformers covered by this rulemaking. None of these seven major manufacturers of liquid-immersed distribution transformers are small businesses. Most liquid-immersed distribution transformers are manufactured domestically. Electric utilities compose the customer base and typically buy on a first-cost basis. Many small manufacturers position themselves towards the higher end of the market or in particular product niches, such as network transformers or harmonic mitigating transformers, but, in general, competition is based on price after a given unit's specs are prescribed by a customer. None of the three small businesses have a market share larger than five percent of the liquid-immersed distribution transformer market.

Low-Voltage Dry-Type Distribution Transformer Small Businesses

LVDT distribution transformers account for approximately 16 percent of all distribution shipments covered by this rulemaking. Eleven major manufacturers supply more than 80 percent of the market for LVDT distribution transformers covered by this rulemaking. Two of these 11 major LVDT distribution transformer manufacturers are small businesses. The majority of LVDT distribution transformers are manufactured outside the U.S., mostly in Canada and Mexico. 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. However, there are universities and other buildings that purchase LVDT based on efficiency as more and more organizations are striving to get to reduced or net-zero emission targets.

In the LVDT market, lower volume manufacturers typically do not compete directly with larger volume manufacturers, as these lower volume manufacturers are frequently not able to compete on a first cost basis. However, there are lower volume manufactures that do serve customers that purchase more efficient LVDT distribution transformers. Lastly, there are some smaller firms that focus on the engineering and design of LVDT distribution transformers and source the production of some parts of the distribution transformer, most frequently the cores, to another company that manufactures those components.

Medium-Voltage Dry-Type Distribution Transformer Small Businesses

MVDT distribution transformers account for less than one percent of all distribution transformer shipments covered by this rulemaking. Eight major manufacturers supply more than 80 percent of the market for MVDT distribution transformers covered by this rulemaking. Two of the eight major MVDT distribution transformer manufacturers are small businesses. The rest of MVDT distribution transformer market is served by a mix of large and small manufactures. Most MVDT distribution transformers are manufactured domestically. Electric utilities and industrial users make up most of the customer base and typically buy on first-cost or features other than efficiency.

4. Description of Reporting, Recordkeeping, and Other Compliance Requirements

Liquid-Immersed Distribution Transformers

DOE is adopting energy conservation standards at TSL 3 for liquid-immersed distribution transformers. For liquid-immersed distribution transformers, TSL 3 is a combination of EL 2 and EL 4 for most liquid-immersed distribution transformer equipment classes.

Based on the LCC consumer choice model, DOE anticipates that most

[202] See: *www.nema.org/membership/manufacturers*.

[203] See: *www.regulations.doe.gov/certification-data*.

[204] See: *cacertappliances.energy.ca.gov*.

[205] Therefore, there are a total of six small businesses that manufacture LVDT distribution transformers. Three that exclusively manufacture LVDT distribution transformers and three that manufacture both LVDT and MVDT distribution transformers.

liquid-immersed distribution transformer manufacturers would use primarily grain-oriented with amorphous cores at select kVA ranges in their distribution transformers to meet these adopted energy conservation standards. While DOE anticipates that several large liquid-immersed distribution transformer manufacturers would make significant capital investments to accommodate the production of amorphous cores, DOE does not anticipate that any small businesses will make these capital investments to be able to produce their own amorphous cores, based on the large capital investments needed to be able to make amorphous cores and the limited ability for small businesses to access large capital investments. Based on manufacturer interviews and market research, DOE was not able to identify any liquid-immersed small businesses that manufacture their own cores. Therefore, DOE anticipates that all liquid-immersed small manufacturers would continue to outsource their production of distribution transformer cores. However, instead of outsourcing exclusively GOES cores they will now outsource a combination of GOES cores and amorphous cores for most of the liquid-immersed distribution transformers that they manufacture in order to comply with the adopted energy conservation standard for liquid-immersed distribution transformers.

DOE acknowledges that there is uncertainty if these small businesses will be able to find core manufacturers that will supply them with amorphous cores in order to comply with the adopted energy conservation standards for liquid-immersed distribution transformers. DOE anticipates that there will be an increase in the number of large liquid-immersed distribution transformer manufacturers that will outsource the production of their cores to core manufacturers capable of producing amorphous cores. This could increase the competition for small businesses to procure amorphous cores for their distribution transformers. Small businesses manufacturing liquid-immersed distribution transformers must be able to procure amorphous cores suitable for their distribution transformers at a cost that allows them to continue to be competitive in the market.

Based on feedback received during manufacturer interviews, DOE does not anticipate that liquid-immersed small businesses that are currently not producing their own cores would have to make a significant capital investment in their production lines to be able to use amorphous cores, that are purchased from a core manufacturer, in the distribution transformers that they manufacture. There will be some additional product conversion costs, in the form of additional R&D and testing, that will need to be incurred by small businesses that manufacture liquid-immersed distribution transformers, even if they do not manufacture their own cores. The methodology used to calculate product conversion costs, described in section IV.J.2.c of this document, estimates that manufacturers would incur approximately one and a half additional years of R&D expenditure to redesign their distribution transformers to be capable of accommodating the use of an amorphous core. Based on the financial parameters used in the GRIM, DOE estimated that the normal annual R&D is approximately 3.0 percent of annual revenue. Therefore, liquid-immersed small businesses would incur an additional 4.5 percent of annual revenue to redesign their distribution transformers to be able to accommodate using amorphous cores that were purchased from core manufacturers.

Low-Voltage Dry-Type Distribution Transformers

DOE is adopting amended energy conservation standards to be at TSL 3 for LVDT distribution transformers. For LVDT distribution transformers, TSL 3 corresponds to EL 3 for all LVDT distribution transformer equipment classes.

Based on the LCC consumer choice model, DOE anticipates that approximately 30 percent of LVDT distribution transformer manufacturers would use amorphous cores in their distribution transformers to meet these adopted energy conservation standards. Based on manufacturer interviews and market research, DOE was able to identify one LVDT small business that manufactures their own cores. The one LVDT small business that is currently manufacturing their own cores would have to make a business decision to either continue making GOES cores that they currently manufacture, make a large capital investment to be able to manufacture amorphous cores, or to outsource the production of amorphous cores. Outsourcing the production of their cores would be a significant change in their production process and could result in a reduction in this small business' market share in the LVDT distribution transformer market.

The other LVDT small businesses that are currently outsourcing their cores will continue to outsource their cores. These LVDT small businesses will have to make a business decision either to continue outsourcing GOES cores that they currently use in their LVDT distribution transformers or to find a core manufacturer that is capable of producing amorphous cores and outsource the production of amorphous cores.

DOE acknowledges that there is uncertainty if these small businesses will be able to find core manufacturers that will supply them with amorphous cores in order to comply with the adopted energy conservation standards for LVDT distribution transformers. DOE anticipates that there will be an increase in the number of large LVDT distribution transformer manufacturers that will outsource the production of their cores to core manufacturers capable of producing amorphous cores. This could increase the competition for small businesses to procure amorphous cores for their LVDT distribution transformers. However, small businesses manufacturing LVDT distribution transformers will still be able to meet the adopted energy conservation standards using GOES cores.

Based on feedback received during manufacturer interviews, DOE does not anticipate that small businesses that are currently not producing their own cores would have to make a significant capital investment in their production lines to be able to meet the adopted energy conservation standards for LVDT distribution transformers. There will be some additional product conversion costs, in the form of additional R&D and testing, that will need to be incurred by small businesses that manufacture LVDT distribution transformers, even if they do not manufacture their own cores. The methodology used to calculate product conversion costs, described in section IV.J.2.c estimates that manufacturers would incur approximately one and a half additional years of R&D expenditure to redesign their distribution transformers to be capable of accommodating the use of an amorphous core and 75 percent of annual R&D expenditures to redesign their distribution transformers that continue to use GOES cores. Based on the financial parameters used in the GRIM, DOE estimated that the normal annual R&D is approximately 3.0 percent of annual revenue. Therefore, LVDT small businesses would incur an additional 2.25 to 4.5 percent of annual revenue to redesign their distribution transformers, depending on if they choose to continue to use GOES cores or amorphous cores, to meet the adopted energy conservation standard for LVDT distribution transformers, which are set at TSL 3.

Medium-Voltage Dry-Type Distribution Transformers

DOE is adopting energy conservation standards to be at TSL 2 for MVDT distribution transformers. This corresponds to EL 2 for all MVDT distribution transformer equipment classes. Based on the LCC consumer choice model, DOE only anticipates that approximately 12 percent of MVDT distribution transformer manufacturers would use amorphous cores in their MVDT distribution transformers to meet these adopted energy conservation standards. DOE does not anticipate that MVDT distribution transformer manufacturers would make significant investments to either be able to produce cores capable of meeting these adopted amended energy conservation standards or be able to integrate more efficient purchased cores from core manufacturers. There will be some additional product conversion costs, in the form of additional R&D and testing, that will need to be incurred by small businesses that manufacture MVDT distribution transformers, even if they do not manufacture their own cores. The methodology used to calculate product conversion costs, described in section IV.J.2.c of this document, estimates that manufacturers would incur approximately 75 percent of additional R&D expenditure to redesign their distribution transformers to higher efficiency levels, when continuing to use GOES cores. Based on the financial parameters used in the GRIM, DOE estimated that the normal annual R&D is approximately 3.0 percent of annual revenue. Therefore, MVDT small businesses would include an additional 2.25 percent of annual revenue to redesign, MVDT distribution transformers to higher efficiency levels that could be met without using amorphous cores.

5. Significant Alternatives Considered and Steps Taken To Minimize Significant Economic Impacts on Small Entities

The discussion in the previous section analyzes impacts on small businesses that would result from DOE's proposed rule, represented by TSL 3 for liquid-immersed distribution transformer equipment classes; TSL 3 for LVDT equipment classes; and TSL 2 for MVDT equipment classes. In reviewing alternatives to the proposed rule, DOE examined energy conservation standards set at lower efficiency levels. While lower TSLs would reduce the impacts on small business manufacturers, it would come at the expense of a reduction in energy savings. For liquid-immersed equipment classes TSL 1 achieves 84 percent lower energy savings compared to the energy savings at TSL 3; and TSL 2 achieves 58 percent lower energy savings compared to the energy savings at TSL 3. For LVDT equipment classes TSL 1 achieves 77 percent lower energy savings compared to the energy savings at TSL 3; and TSL 2 achieves 65 percent lower energy savings compared to the energy savings at TSL 3. For MVDT equipment classes TSL 1 achieves 29 percent lower energy savings compared to the energy savings at TSL 2.

Establishing standards at TSL 3 for liquid-immersed equipment classes and LVDT equipment classes and TSL 2 for MVDT equipment classes balances the benefits of the energy savings at the adopted TSLs with the potential burdens placed on distribution transformer manufacturers, including small business manufacturers. Accordingly, DOE is not adopting one of the other TSLs considered in the analysis, or the other policy alternatives examined as part of the regulatory impact analysis and included in chapter 17 of the final rule TSD.

Additional compliance flexibilities may be available through other means. Manufacturers subject to DOE's energy efficiency standards may apply to DOE's Office of Hearings and Appeals for exception relief under certain circumstances. Manufacturers should refer to 10 CFR part 430, subpart E, and 10 CFR part 1003 for additional details.

C. Review Under the Paperwork Reduction Act

Manufacturers of distribution transformers must certify to DOE that their products comply with any applicable energy conservation standards. In certifying compliance, manufacturers must test their products 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. (*See* generally 10 CFR part 429). 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 35 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 of 1969 (NEPA), DOE has analyzed this rule in accordance with NEPA and DOE's NEPA implementing regulations (10 CFR part 1021). DOE has determined that this rule qualifies for categorical exclusion under 10 CFR part 1021, subpart D, appendix B5.1 because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, none of the exceptions identified in B5.1(b) apply, no extraordinary circumstances exist that require further environmental analysis, and it meets the requirements for application of a categorical exclusion. *See* 10 CFR 1021.410. Therefore, DOE has determined that promulgation of this rule is not a major Federal action significantly affecting the quality of the human environment within the meaning of NEPA, and does not require an environmental assessment or an environmental impact statement.

E. Review Under Executive Order 13132

E.O. 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. DOE has examined this rule and has determined that it would not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the equipment that is the subject of this 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. 6316(a) and (b); 42 U.S.C. 6297) Therefore, 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 E.O. 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, (3) provide a clear legal standard for affected conduct rather than a general standard, and (4) promote simplification and burden reduction. 61 FR 4729 (Feb. 7, 1996). Regarding the review required by section 3(a), section 3(b) of E.O. 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 E.O. 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 E.O. 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. Public Law 104–4, sec. 201 (codified at 2 U.S.C. 1531). For a 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 them. 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 *www.energy.gov/sites/prod/files/gcprod/documents/umra_97.pdf.*

DOE has concluded that this final rule may require expenditures of $100 million or more in any one year 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 this document and the TSD for this final rule respond to those requirements.

Under section 205 of UMRA, DOE 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. 6316(a) and 42 U.S.C. 6295(m)(1), this final rule establishes amended 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, as required by 42 U.S.C. 6316(a); 6295(o)(2)(A) and 6295(o)(3)(B). A full discussion of the alternatives considered by DOE is presented in chapter 17 of the TSD for this 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 proposed rule or policy that may affect family well-being. Although this final rule would not have any impact on the autonomy or integrity of the family as an institution as defined, this final rule could impact a family's well-being. When developing a Family Policymaking Assessment, agencies must assess whether: (1) the action strengthens or erodes the stability or safety of the family and, particularly, the marital commitment; (2) the action strengthens or erodes the authority and rights of parents in the education, nurture, and supervision of their children; (3) the action helps the family perform its functions, or substitutes governmental activity for the function; (4) the action increases or decreases disposable income or poverty of families and children; (5) the proposed benefits of the action justify the financial impact on the family; (6) the action may be carried out by State or local government or by the family; and whether (7) the action establishes an implicit or explicit policy concerning the relationship between the behavior and personal responsibility of youth, and the norms of society.

DOE has considered how the benefits of this final rule compare to the possible financial impact on a family (the only factor listed that is relevant to this proposed rule). As part of its rulemaking process, DOE must determine whether the energy conservation standards enacted in this final rule are economically justified. As discussed in sections V.C.1 through V.C.3 of this document, DOE has determined that the standards enacted in this final rule are economically justified because the benefits to consumers would far outweigh the costs to manufacturers. Moreover, as discussed further in section V.B.1 of this document, DOE has determined that for utilities who serve low population densities, average LCC savings and PBP at the considered efficiency levels are not substantially different, and are often improved (*i.e.,* higher LCC savings and lower PBP), as compared to the average for all utilities. Further, the standards will also result in climate and health benefits for families.

I. Review Under Executive Order 12630

Pursuant to E.O. 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights,'' 53 FR 8859 (March 18, 1988), DOE has determined that this rule 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 information quality guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (Feb. 22, 2002), and DOE's guidelines were published at 67 FR 62446 (Oct. 7, 2002). Pursuant to OMB Memorandum M–19–15, Improving Implementation of the Information Quality Act (April 24, 2019), DOE published updated guidelines which are available at *www.energy.gov/sites/prod/files/2019/12/f70/DOE%20Final%20Updated%20IQA%20Guidelines%20Dec%202019.pdf.* DOE has reviewed this 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

E.O. 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 this regulatory action, which sets forth amended energy conservation standards for distribution transformers, is not a significant energy action because the 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 on this final rule.

L. Information Quality

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 (Jan. 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 2664, 2667.

In response to OMB's Bulletin, DOE conducted formal peer reviews of the energy conservation standards development process and the analyses that are typically used and prepared a report describing that peer review.[206] 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. Because available data, models, and technological understanding have changed since 2007, DOE has engaged with the National Academy of Sciences to review DOE's analytical methodologies to ascertain whether modifications are needed to improve DOE's analyses. DOE is in the process of evaluating the resulting report.[207]

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 the Office of Information and Regulatory Affairs has determined that the rule meets the criteria set forth in 5 U.S.C. 804(2).).

VII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of this final rule.

List of Subjects in 10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation test procedures, Reporting and recordkeeping requirements.

Signing Authority

This document of the Department of Energy was signed on April 3, 2024, by Jeffrey Marootian, Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy, pursuant to delegated authority from the Secretary of Energy. That document with the original signature and date is maintained by DOE. For administrative purposes only, and in compliance with requirements of the Office of the Federal Register, the undersigned DOE Federal Register Liaison Officer has been authorized to sign and submit the document in electronic format for publication, as an official document of the Department of Energy. This administrative process in no way alters the legal effect of this document upon publication in the **Federal Register**.

Signed in Washington, DC, on April 4, 2024.

Treena V. Garrett,

Federal Register Liaison Officer, U.S. Department of 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, as set forth below:

[206] The 2007 ''Energy Conservation Standards Rulemaking Peer Review Report'' is available at the following website: *energy.gov/eere/buildings/downloads/energy-conservation-standards-rulemaking-peer-review-report-0* (last accessed Jan. 16, 2024).

[207] The report is available at *www.nationalacademies.org/our-work/review-of-methods-for-setting-building-and-equipment-performance-standards.*

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; 28 U.S.C. 2461 note.

■ 2. Amend § 431.192 by:
■ a. Revising the definitions for ''Distribution transformer'', ''Drive (isolation) transformer'', ''Nonventilated transformer'', ''Sealed transformer'', and ''Special-impedance transformer'';
■ b. Adding in alphabetical order a definition for ''Submersible distribution transformer''; and
■ c. Revising the definitions for ''Transformer with a tap range of 20 percent or more'' and ''Uninterruptible power supply transformer''.

The revisions and addition read as follows:

§ 431.192 Definitions.

* * * * *

Distribution transformer means a transformer that—

(1) Has an input line voltage of 34.5 kV or less;

(2) Has an output line voltage of 600 V or less;

(3) Is rated for operation at a frequency of 60 Hz; and

(4) Has a capacity of 10 kVA to 5000 kVA for liquid-immersed units and 15 kVA to 5000 kVA for dry-type units; but

(5) The term ''distribution transformer'' does not include a transformer that is an—

(i) Autotransformer;
(ii) Drive (isolation) transformer;
(iii) Grounding transformer;
(iv) Machine-tool (control) transformer;
(v) Nonventilated transformer;
(vi) Rectifier transformer;
(vii) Regulating transformer;
(viii) Sealed transformer;
(ix) Special-impedance transformer;
(x) Testing transformer;
(xi) Transformer with tap range of 20 percent or more;
(xii) Uninterruptible power supply transformer; or
(xiii) Welding transformer.

Drive (isolation) transformer means a transformer that:

(1) Isolates an electric motor from the line;

(2) Accommodates the added loads of drive-created harmonics;

(3) Is designed to withstand the additional mechanical stresses resulting from an alternating current adjustable frequency motor drive or a direct current motor drive; and

(4) Has a rated output voltage that is neither ''208Y/120'' nor ''480Y/277''.

* * * * *

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

* * * * *

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

Special-impedance transformer means a transformer built to operate at an impedance outside of the normal impedance range for that transformer's kVA rating. The normal impedance range for each kVA rating for liquid-immersed and dry-type transformers is shown in Tables 1 and 2, respectively.

TABLE 1 TO THE DEFINITION O ''SPECIAL-IMPEDANCE TRANSFORMER''—NORMAL IMPEDANCE RANGES FOR LIQUID-IMMERSED TRANSFORMERS

Single-phase transformers		Three-phase transformers	
kVA	Impedance (%)	kVA	Impedance (%)
10 <= kVA < 50	1.0–4.5	15 <= kVA < 75	1.0–4.5
50 <= kVA < 250	1.5–4.5	75 <= kVA < 112.5	1.0–5.0
250 <= kVA < 500	1.5–6.0	112.5 <= kVA < 500	1.2–6.0
500 <= kVA < 667	1.5–7.0	500 <= kVA < 750	1.5–7.0
667 <= kVA <= 833	5.0–7.5	750 <= kVA <= 5000	5.0–7.5

TABLE 2 TO THE DEFINITION O ''SPECIAL-IMPEDANCE TRANSFORMER''—NORMAL IMPEDANCE RANGES FOR DRY-TYPE TRANSFORMERS

Single-phase transformers		Three-phase transformers	
kVA	Impedance (%)	kVA	Impedance (%)
10 <= kVA < 50	1.0–4.5	15 <= kVA < 75	1.0–4.5
50 <= kVA < 250	1.5–4.5	75 <= kVA < 112.5	1.0–5.0
250 <= kVA < 500	1.5–6.0	112.5 <= kVA < 500	1.2–6.0
500 <= kVA < 667	1.5–7.0	500 <= kVA < 750	1.5–7.0
667 <= kVA <= 833	5.0–7.5	750 <= kVA <= 5000	5.0–7.5

Submersible distribution transformer means a liquid-immersed distribution transformer, so constructed as to be operable when fully or partially submerged in water including the following features—

(1) Has sealed-tank construction; and

(2) Has the tank, cover, and all external appurtenances made of corrosion-resistant material or with appropriate corrosion resistant surface treatment to induce the components surface to be corrosion resistant.

* * * * *

Transformer with tap range of 20 percent or more means a transformer with multiple voltage taps, each capable of operating at full, rated capacity (kVA), whose range, defined as the difference between the highest voltage tap and the lowest voltage tap, is 20 percent or more of the highest voltage tap.

Uninterruptible power supply transformer means a transformer that is used within an uninterruptible power system, which in turn supplies power to loads that are sensitive to power failure, power sages, over voltage, switching transients, line notice, and other power quality factors. It does not include distribution transformers at the input, output, or by-pass of an uninterruptible power system.

* * * * *

■ 3. Amend § 431.196 by:

■ a. Revising paragraph (a)(2) and adding paragraph (a)(3);

■ b. Revising paragraph (b)(2) and adding paragraphs (b)(3) and (4);

■ c. Revising paragraph (c)(2) and adding paragraph (c)(3); and

■ d. Adding paragraph (e).

The revisions and additions read as follows:

§ 431.196 Energy conservation standards and their effective dates.

(a) * * *

(2) The efficiency of a low-voltage, dry-type distribution transformer manufactured on or after January 1, 2016, but before April 23, 2029, shall be no less than that required for the applicable kVA rating in the following table. 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.

TABLE 2 TO PARAGRAPH (a)(1)

Single-phase		Three-phase	
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

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 this subpart K.

(3) The efficiency of a low-voltage dry-type distribution transformer manufactured on or after April 23, 2029, shall be no less than that required for their kVA rating in the following table. 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.

TABLE 3 TO PARAGRAPH (a)(3)

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
15	98.39	15	98.31
25	98.60	30	98.58
37.5	98.74	45	98.72
50	98.81	75	98.88
75	98.95	112.5	98.99
100	99.02	150	99.06
167	99.09	225	99.15
250	99.16	300	99.22
333	99.23	500	99.31
		750	99.38
		1000	99.42

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 this subpart K.

(b) * * *

(2) The efficiency of a liquid-immersed distribution transformer, including submersible distribution transformers, manufactured on or after January 1, 2016, but before April 23, 2029, shall be no less than that required for their kVA rating in the following table. Liquid-immersed distribution transformers, including submersible 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.

TABLE 5 TO PARAGRAPH (b)(2)

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—Procedure, appendix A to this subpart K.

(3) The efficiency of a liquid-immersed distribution transformer, that is not a submersible distribution transformer, manufactured on or after April 23, 2029, shall be no less than that required for their kVA rating in the following table. 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.

TABLE 6 TO PARAGRAPH (b)(3)

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.77	15	98.92
15	98.88	30	99.06
25	99.00	45	99.14
37.5	99.10	75	99.22
50	99.15	112.5	99.29
75	99.23	150	99.33
100	99.29	225	99.38
167	99.46	300	99.42
250	99.51	500	99.38
333	99.54	750	99.43
500	99.59	1000	99.46
667	99.62	1500	99.51
833	99.64	2000	99.53
		2500	99.55
		3750	99.54
		5000	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 this subpart K.

(4) The efficiency of a submersible distribution transformer, manufactured on or after April 23, 2029, shall be no less than that required for their kVA rating in the following table. Submersible 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.

TABLE 7 TO PARAGRAPH (b)(4)

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

TABLE 7 TO PARAGRAPH (b)(4)—Continued

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
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—Procedure, appendix A to this subpart K.

(c) * * *

(2) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after January 1, 2016, but before April 23, 2029, shall be no less than that required for their kVA and BIL rating in the following table. 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.

TABLE 9 TO PARAGRAPH (c)(2)

kVA	Single-phase			kVA	Three-phase		
	BIL[1]				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

[1] 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 this subpart K.

(3) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after April 23, 2029, shall be no less than that required for their kVA and BIL rating in the following table. 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.

TABLE 10 TO PARAGRAPH (c)(3)

kVA	Single-phase			kVA	Three-phase		
	BIL[1]				BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.29	98.07	....	15	97.75	97.46	....

TABLE 10 TO PARAGRAPH (c)(3)—Continued

kVA	Single-phase BIL[1] 20–45 kV Efficiency (%)	Single-phase BIL[1] 46–95 kV Efficiency (%)	Single-phase BIL[1] ≥96 kV Efficiency (%)	kVA	Three-phase BIL 20–45 kV Efficiency (%)	Three-phase BIL 46–95 kV Efficiency (%)	Three-phase BIL ≥96 kV Efficiency (%)
25	98.50	98.31	....	30	98.11	97.87	....
37.5	98.64	98.47	....	45	98.29	98.07	....
50	98.74	98.58	....	75	98.50	98.32	....
75	98.86	98.71	98.68	112.5	98.67	98.52	....
100	98.94	98.80	98.77	150	98.79	98.66	....
167	99.06	98.95	98.92	225	98.94	98.82	98.71
250	99.16	99.06	99.02	300	99.04	98.93	98.82
333	99.23	99.13	99.09	500	99.18	99.09	99.00
500	99.30	99.21	99.18	750	99.29	99.21	99.12
667	99.34	99.26	99.24	1000	99.35	99.28	99.20
833	99.38	99.31	99.28	1500	99.43	99.37	99.29
	....	....	....	2000	99.49	99.42	99.35
	....	....	....	2500	99.52	99.47	99.40
	....	....	....	3750	99.50	99.44	99.40
	....	....	....	5000	99.48	99.43	99.39

[1] 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 this subpart K.

* * * * *

(e) *Severability.* The provisions of paragraphs (a) through (d) of this section are separate and severable from one another. Should a court of competent jurisdiction hold any provision(s) of this section to be stayed or invalid, such action shall not affect any other provision of this section.

Note: The following letter will not appear in the Code of Federal Regulations.

U.S. DEPARTMENT OF JUSTICE
Antitrust Division
RFK Main Justice Building
950 Pennsylvania Avenue NW
Washington, DC 20530–0001

March 20, 2023

Ami Grace-Tardy
Assistant General Counsel for Legislation, Regulation and Energy Efficiency
U.S. Department of Energy
Washington, DC 20585
Ami.Grace-Tardy@hw.doe.gov

Re: Energy Conservation Standards for Distribution Transformers, DOE Docket No. EERE–2019–BT–STD–0018

Dear Assistant General Counsel Grace-Tardy:

I am responding to your January 19, 2023 letter seeking the views of the Attorney General about the potential impact on competition of proposed energy conservation standards for 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). The Assistant Attorney General for the Antitrust Division has authorized me, as the Policy Director for the Antitrust Division, to provide the Antitrust Division's views regarding the potential impact on competition of proposed energy conservation standards on his behalf.

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.

We have reviewed the proposed standards contained in the Notice of proposed rulemaking and request for comment (88 FR 1722, January 11, 2023) and the related Technical Support Document. We have also reviewed public comments and information presented at the Webinar of the Public Meetings held on September 29, 2021 and February 16, 2023.

Based on this review, our conclusion is that the proposed energy conservation standards for distribution transformers are unlikely to have a significant adverse impact on competition.

Sincerely,
David G.B. Lawrence,
Policy Director.

[FR Doc. 2024–07480 Filed 4–19–24; 8:45 am]

BILLING CODE 6450–01–P