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: Notice of proposed rulemaking and announcement of public meeting.

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 determine whether more-stringent, standards would be technologically feasible and economically justified, and would result in significant energy savings. In this notice of proposed rulemaking (''NOPR''), DOE proposes amended energy conservation standards for distribution transformers, and also announces a public meeting to receive comment on these proposed standards and associated analyses and results.

DATES: DOE will hold a public meeting via webinar on Thursday, February 16, 2023, from 1:00 p.m. to 4:00 p.m. See section VII, ''Public Participation,'' for webinar registration information, participant instructions and information about the capabilities available to webinar participants.

Comments: DOE will accept comments, data, and information regarding this NOPR no later than March 13, 2023.

Comments regarding the likely competitive impact of the proposed standard should be sent to the Department of Justice contact listed in the **ADDRESSES** section on or before February 10, 2023.

Interested persons are encouraged to submit comments using the Federal eRulemaking Portal at *www.regulations.gov.* Follow the instructions for submitting comments. Alternatively, interested persons may submit comments, identified by docket number EERE–2019–BT–STD–0018, by any of the following methods:

Email: DistributionTransfromers2019STD 0018@ee.doe.gov. Include the docket number EERE–2019–BT–STD–0018 in the subject line of the message.

Postal Mail: Appliance and Equipment Standards Program, U.S. Department of Energy, Building Technologies Office, Mailstop EE–5B, 1000 Independence Avenue SW, Washington, DC 20585–0121. Telephone: (202) 287–1445. If possible, please submit all items on a compact disc (''CD''), in which case it is not necessary to include printed copies.

Hand Delivery/Courier: Appliance and Equipment Standards Program, U.S. Department of Energy, Building Technologies Office, 950 L'Enfant Plaza SW, 6th Floor, Washington, DC 20024. Telephone: (202) 287–1445. If possible, please submit all items on a CD, in which case it is not necessary to include printed copies.

No telefacsimiles (''faxes'') will be accepted. For detailed instructions on submitting comments and additional information on this process, see section IV of this document.

Docket: The docket for this activity, which includes **Federal Register** notices, 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. See section VII of this document for information on how to submit comments through *www.regulations.gov.*

EPCA requires the Attorney General to provide DOE a written determination of whether the proposed standard is likely to lessen competition. The U.S. Department of Justice Antitrust Division invites input from market participants and other interested persons with views on the likely competitive impact of the proposed standard. Interested persons may contact the Division at *energy.standards@usdoj.gov* on or before the date specified in the **DATES** section. Please indicate in the ''Subject'' line of your email the title and Docket Number of this proposed rule.

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. Telephone: (202) 586–9870. Email: *ApplianceStandards Questions@ee.doe.gov.*

Mr. Matthew Ring, U.S. Department of Energy, Office of the General Counsel, GC–33, 1000 Independence Avenue SW, Washington, DC 20585–0121. Telephone: (202) 586–2555. Email: *matthew.ring@hq.doe.gov.*

For further information on how to submit a comment, review other public comments and the docket, or participate in the public meeting, contact the Appliance and Equipment Standards Program staff at (202) 287–1445 or by email: *ApplianceStandardsQuestions@ ee.doe.gov.*

SUPPLEMENTARY INFORMATION:

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I. Synopsis of the Proposed Rule

The EPCA,[1] (42 U.S.C. 6291–6317, as codified) authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. Title III, Part B [2] of EPCA (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for ''Consumer Products Other Than Automobiles.'' Title III, Part C [3] of EPCA (42 U.S.C.

[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 re-designated Part A.

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

Continued

6311–6317, as codified), 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))

Pursuant to EPCA, 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 a significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B)) EPCA also provides that not later than 6 years after 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 notice of proposed rulemaking 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))

In accordance with these and other statutory provisions discussed in this document, DOE proposes amended energy conservation standards for distribution transformers. The proposed standards, which are expressed in efficiency as a percentage, are shown in Table I.1 of this document. These proposed standards, if adopted, would apply to all distribution transformers listed in Table I.1, Table I.2, and Table I.3 manufactured in, or imported into, the United States starting on the date 3 years after the publication of the final rule for this rulemaking.

TABLE I.1—PROPOSED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
15	98.84	15	98.72
25	98.99	30	98.93
37.5	99.09	45	99.03
50	99.14	75	99.16
75	99.24	112.5	99.24
100	99.30	150	99.29
167	99.35	225	99.36
250	99.40	300	99.41
333	99.45	500	99.48
		750	99.54
		1,000	99.57

TABLE I.2—PROPOSED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.96	15	98.92
15	99.05	30	99.06
25	99.16	45	99.13
37.5	99.24	75	99.22
50	99.29	112.5	99.29
75	99.35	150	99.33
100	99.40	225	99.38
167	99.46	300	99.42
250	99.51	500	99.48
333	99.54	750	99.52
500	99.59	1,000	99.54
667	99.62	1,500	99.58
833	99.64	2,000	99.61
		2,500	99.62
		3,750	99.66
		5,000	99.68

Program for Certain Commercial and Industrial Equipment. DOE refers to distribution transformers generally as ''covered equipment'' in this document.

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

Single-phase				Three-phase			
kVA	BIL*			kVA	BIL*		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.29	98.07		15	97.74	97.45	
25	98.49	98.30		30	98.11	97.86	
37.5	98.64	98.47		45	98.29	98.07	
50	98.74	98.58		75	98.49	98.31	
75	98.86	98.71	98.68	112.5	98.67	98.52	
100	98.94	98.80	98.77	150	98.78	98.66	
167	99.06	98.95	98.92	225	98.94	98.82	98.71
250	99.16	99.05	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	99.23	1,000	99.35	99.28	99.20
833	99.38	99.31	99.28	1,500	99.43	99.37	99.29
				2,000	99.49	99.42	99.35
				2,500	99.52	99.47	99.40
				3,750	99.58	99.53	99.47
				5,000	99.62	99.58	99.51

* BIL means basic impulse insulation level.

A. Benefits and Costs to Consumers

Table I.4 presents DOE's evaluation of the monetized impacts of the proposed 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 representative unit 14, 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 NOPR, the term consumer refers to different populations that purchase and bear the operating costs of distribution transformers. Consumers vary by transformer type; 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.

TABLE I.4—IMPACTS OF PROPOSED ENERGY CONSERVATION STANDARDS ON CONSUMERS OF DISTRIBUTION TRANSFORMERS

Equipment class	Representative unit	Average LCC savings (2021$)	Simple payback period (years)
1	1	72	16.0
1	2	131	10.1
1	3	1,029	12.2
2	4	511	11.9
2	5	1,543	13.8
2	17	6,594	15.8
12	15	* n.a.	* n.a.
12	16	* n.a.	* n.a.
3	6	147	11.7
4	7	564	8.9
4	8	722	11.8
6	9	887	2.4
6	10	653	11.4
8	11	226	11.9
8	12	3,051	1.1
8	18	22,797	8.1
10	13	228	12.4
10	14	−2,856	26.1
10	19	8,082	11.3

* No-new standards are currently being proposed for equipment class 12, ''n.a'' indicates that there are no consumer savings.

[4] The average LCC savings and simple PBP 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. The determination of the distribution of efficiencies in the no-new-standards case is a function of the units selected from the consumer choice model. (*see* section IV.F.3 of this document).

DOE's analysis of the impacts of the proposed 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 (2022–2056). Using a real discount rate of 7.4 percent for liquid-immersed distribution transformers, 11.1 percent for low-voltage dry-type (''LVDT'') distribution transformers, and 9.0 percent for medium-voltage dry-type (''MVDT'') distribution transformers, DOE estimates that the INPV for manufacturers of distribution transformers in the case without amended standards is $1,384 million in 2021$ for liquid-immersed distribution transformers, $194 million in 2021$ for LVDT distribution transformers, and $87 million in 2021$ for MVDT distribution transformers. Under the proposed standards, the change in INPV is estimated to range from –18.1 percent to –10.9 percent for liquid-immersed distribution transformers which represents a change in INPV of approximately −$251.3 million to −$151.0 million; from –31.4 percent to –17.2 percent for LVDT distribution transformers, which represents a change in INPV of approximately −$61.0 million to −$33.5 million; and –3.0 percent to –0.9 percent for MVDT distribution transformers, which represents a change in INPV of approximately −$2.7 million to −$0.8 million. In order to bring products into compliance with amended standards, it is estimated that the industry would incur total conversion costs of $270.6 million for liquid-immersed distribution transformer, $69.4 million for LVDT distribution transformers, and $3.1 million for MVDT distribution transformers.

DOE's analysis of the impacts of the proposed standards on manufacturers is described in section IV.J of this document. The analytic results of the manufacturer impact analysis (''MIA'') are presented in section V.B.2 of this document.

C. National Benefits and Costs[5]

1. Liquid-Immersed Distribution Transformers

DOE's analyses indicate that the proposed energy conservation standards for liquid-immersed 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 (2027–2056) amount to 8.02 quadrillion British thermal units (''Btu''), or quads.[6] This represents a fleet savings of 36 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 proposed standards for distribution transformers ranges from 0.26 billion (2021$) (at a 7-percent discount rate) to 5.30 billion (2021$) (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for distribution transformers purchased in 2027–2056.

In addition, the proposed standards for liquid-immersed distribution transformers are projected to yield significant environmental benefits. DOE estimates that the proposed standards would result in cumulative emission reductions (over the same period as for energy savings) of 256.27 million metric tons (''Mt'')[7] of carbon dioxide (''CO_2''), 99.71 thousand tons of sulfur dioxide (''SO_2''), 403.57 thousand tons of nitrogen oxides (''NO_X''), 1,846.56 thousand tons of methane (''CH_4''), 2.32 thousand tons of nitrous oxide (''N_2O''), and 0.65 tons of mercury (''Hg'').[8]

DOE estimates 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''). Together these represent the social cost of GHG (SC–GHG). DOE used interim SC–GHG values developed by an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG),[9] as 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 $8.66 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 SC–GHG estimates.[10]

DOE also estimates health benefits from SO_2 and NO_X emissions reductions.[11] DOE estimates the present value of the health benefits would be $4.69 billion using a 7-percent discount rate, and $15.57 billion using a 3-percent discount rate.[12] 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.

Table I.5 summarizes the monetized benefits and costs expected to result from the proposed standards for liquid-immersed distribution transformers. In the table, total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with 3-percent discount rate, but the Department emphasizes the importance and value of considering the benefits calculated using all four SC–GHG cases. The estimated total net benefits using each of the four cases are

[5] All monetary values in this document are expressed in 2021 dollars.

[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.2 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 2022* (''*AEO2022*''). *AEO2022* represents current federal and state legislation and final implementation of regulations as of the time of its preparation. *See* section IV.K of this document for further discussion of *AEO2022* assumptions that effect air pollutant emissions.

[9] *See* Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates Under Executive Order 13990, Washington, DC, February 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

[10] 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement benefits where appropriate and permissible under law.

[11] DOE estimated the monetized value of SO_2 and NO_X emissions reductions associated with electricity savings using benefit per ton estimates from the EPA. e. *See* section IV.L.2 of this document for further discussion.

[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.

presented in section V.B.8 of this document.

TABLE I.5—SUMMARY OF MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS (TSL 4)

	Billion ($2021)
3% discount rate	
Consumer Operating Cost Savings	12.77
Climate Benefits *	8.66
Health Benefits **	15.57
Total Benefits †	37.01
Consumer Incremental Product Costs ‡	7.48
Net Benefits	29.53
7% discount rate	
Consumer Operating Cost Savings	4.28
Climate Benefits * (3% discount rate)	8.66
Health Benefits **	4.69
Total Benefits †	17.63
Consumer Incremental Product Costs ‡	4.02
Net Benefits	13.61

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO2), methane (SC–CH4), and nitrous oxide (SC–N2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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.69 for net benefits using all four SC–GHG estimates.

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

The benefits and costs of the proposed 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 the benefits of GHG and NO_X and SO_2 emission reductions, all annualized.[13] The national operating savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered products and are measured for the lifetime of distribution transformers shipped in 2027–2056. The benefits associated with reduced emissions achieved as a result of the proposed standards are also calculated based on the lifetime of liquid-immersed distribution transformers shipped in 2027–2056.

Estimates of annualized benefits and costs of the proposed standards are shown in Table I.6. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced NOx and SO_2 emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $424.8 million per year in increased equipment costs, while the estimated annual benefits are $451.9 million in reduced equipment operating costs, $497.4 million in climate benefits, and $495.3 million in health benefits. In this case. The net benefit would amount to $1,019.8 million per year.

[13] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2021, 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.,* 2030), and then discounted the present value from each year to 2021. 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.

TABLE I.6—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS (TSL 4)

Category	Million (2021$/year)		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	733.5	686.9	789.9
Climate Benefits *	497.4	478.9	519.5
Health Benefits **	894.3	860.5	934.8
Total Benefits †	2,125.3	2,026.3	2,244.2
Consumer Incremental Product Costs ‡	429.5	449.0	413.2
Net Benefits	1,695.8	1,577.3	1,831.0
7% discount rate			
Consumer Operating Cost Savings	451.9	425.7	482.2
Climate Benefits * (3% discount rate)	497.4	478.9	519.5
Health Benefits **	495.3	477.9	515.3
Total Benefits †	1,444.7	1,382.5	1,517.0
Consumer Incremental Product Costs ‡	424.8	442.1	409.9
Net Benefits	1,019.8	940.5	1,107.2

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO2), methane (SC–CH4), and nitrous oxide (SC–N2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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.69 for net benefits using all four SC–GHG estimates.

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

2. Low-Voltage Dry-Type Distribution Transformers

DOE's analyses indicate that the proposed energy conservation standards for low-voltage dry-type 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 (2027–2056) amount to 2.47 quadrillion British thermal units (''Btu''), or quads.[14] This represents a fleet savings of 47 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 proposed standards for low-voltage dry-type distribution transformers ranges from 2.63 billion (2021$) (at a 7-percent discount rate) to 9.63 billion (2021$) (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for low-voltage dry-type distribution transformers purchased in 2027–2056.

In addition, the proposed standards for low-voltage dry-type distribution transformers are projected to yield significant environmental benefits. DOE estimates that the proposed standards would result in cumulative emission reductions (over the same period as for energy savings) of 77.57 million metric tons (''Mt'')[15] of carbon dioxide (''CO_2''), 92.81 thousand tons of sulfur dioxide (''SO_2''), 123.44 thousand tons of nitrogen oxides (''NO_X''), 567.30 thousand tons of methane (''CH_4''), 0.70 thousand tons of nitrous oxide (''N_2O''), and 0.19 tons of mercury (''Hg'').[16]

[14] 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.2 of this document.

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

[16] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *Annual Energy Outlook 2022* (''*AEO2022*''). *AEO2022* represents current federal and state legislation and final implementation of regulations as of the time of its preparation. *See* section IV.K of this document for further discussion of *AEO2022* assumptions that effect air pollutant emissions.

DOE estimates 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''). Together these represent the social cost of GHG (SC–GHG). DOE used interim SC–GHG values developed by an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG),[17] as 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 $2.77 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 SC–GHG estimates.)

DOE also estimates health benefits from SO_2 and NO_X emissions reductions.[18] DOE estimates the present value of the health benefits would be $1.53 billion using a 7-percent discount rate, and $4.91 billion using a 3-percent discount rate.[19] 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.

Table I.7 summarizes the monetized benefits and costs expected to result from the proposed standards for low-voltage dry-type distribution transformers. In the table, total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with 3-percent discount rate, but the Department emphasizes the importance and value of considering the benefits calculated using all four SC–GHG cases. The estimated total net benefits using each of the four cases are presented in section V.B.8 of this document.

TABLE I.7—SUMMARY OF MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS (TSL 5)

	Billion ($2021)
3% discount rate	
Consumer Operating Cost Savings	13.45
Climate Benefits *	2.77
Health Benefits **	4.91
Total Benefits †	21.13
Consumer Incremental Product Costs ‡	3.82
Net Benefits	17.31
7% discount rate	
Consumer Operating Cost Savings	4.69
Climate Benefits * (3% discount rate)	2.77
Health Benefits **	1.53
Total Benefits †	8.99
Consumer Incremental Product Costs ‡	2.05
Net Benefits	6.94

Note: This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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.69 for net benefits using all four SC–GHG estimates.

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

[17] See Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates Under Executive Order 13990, Washington, DC, February 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

[18] DOE estimated the monetized value of SO_2 and NO_X emissions reductions associated with electricity savings using benefit per ton estimates from the EPA. *See* section IV.L.2 of this document for further discussion.

[19] 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.

The benefits and costs of the proposed 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 the benefits of GHG and NO_X and SO_2 emission reductions, all annualized.[20] The national operating savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered products and are measured for the lifetime of low-voltage dry-type distribution transformers shipped in 2027–2056. The benefits associated with reduced emissions achieved as a result of the proposed standards are also calculated based on the lifetime of low-voltage dry-type distribution transformers shipped in 2027–2056.

Estimates of annualized benefits and costs of the proposed standards are shown in Table I.8. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced NO_X and SO_2 emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $216.9 million per year in increased equipment costs, while the estimated annual benefits are $495.0 million in reduced equipment operating costs, $159.2 million in climate benefits, and $162.1 million in health benefits. In this case. The net benefit would amount to $599.4 million per year.

TABLE I.8—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY TYPE DISTRIBUTION TRANSFORMERS (TSL 5)

Category	Million (2021$/year)		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	772.1	716.9	831.3
Climate Benefits *	159.2	151.6	165.9
Health Benefits **	281.8	268.3	293.9
Total Benefits †	1,213.1	1,136.7	1,291.1
Consumer Incremental Product Costs ‡	219.3	228.7	208.7
Net Benefits	993.8	908.0	1,082.4
7% discount rate			
Consumer Operating Cost Savings	495.0	462.8	528.7
Climate Benefits * (3% discount rate)	159.2	151.6	165.9
Health Benefits **	162.1	154.9	168.2
Total Benefits †	816.3	769.3	862.8
Consumer Incremental Product Costs ‡	216.9	225.2	207.3
Net Benefits	599.4	544.1	655.5

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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.69 for net benefits using all four SC–GHG estimates.

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

3. Medium Voltage Dry-Type Distribution Transformers

DOE's analyses indicate that the proposed 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 medium-voltage dry-type distribution transformers purchased in the 30-year period that begins in the anticipated

[20] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2021, 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.,* 2030), and then discounted the present value from each year to 2021. 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.

year of compliance with the amended standards (2027–2056) amount to 0.12 quadrillion British thermal units (''Btu''), or quads.[21] This represents a fleet savings of 24 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 proposed standards for medium-voltage dry-type distribution transformers ranges from 0.04 billion (2021$) (at a 7-percent discount rate) to 0.21 billion (2021$) (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for medium-voltage dry-type distribution transformers purchased in 2027–2056.

In addition, the proposed standards for medium-voltage dry-type distribution transformers are projected to yield significant environmental benefits. DOE estimates that the proposed standards would result in cumulative emission reductions (over the same period as for energy savings) of 3.71 million metric tons (''Mt'')[22] of carbon dioxide (''CO_2''), 1.43 thousand tons of sulfur dioxide (''SO_2''), 5.93 thousand tons of nitrogen oxides (''NO_X''), 27.29 thousand tons of methane (''CH_4''), 0.03 thousand tons of nitrous oxide (''N_2O''), and 0.01 tons of mercury (''Hg'').[23]

DOE estimates 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''). Together these represent the social cost of GHG (SC–GHG). DOE used interim SC–GHG values developed by an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG),[24] as discussed in IV.L of this document. For presentational purposes, the climate benefits associated with the average SC–GHG at a 3-percent discount rate are $0.13 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 SC–GHG estimates.)

DOE also estimates health benefits from SO_2 and NO_X emissions reductions.[25] DOE estimates the present value of the health benefits would be $0.07 billion using a 7-percent discount rate, and $0.24 billion using a 3-percent discount rate.[26] 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.

Table I.9 summarizes the monetized benefits and costs expected to result from the proposed standards for medium-voltage dry-type distribution transformers. In the table, total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with 3-percent discount rate, but the Department emphasizes the importance and value of considering the benefits calculated using all four SC–GHG cases. The estimated total net benefits using each of the four cases are presented in section V.B.8 of this document.

TABLE I.9—SUMMARY OF MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS (TSL 2)

	Billion ($2021)
3% discount rate	
Consumer Operating Cost Savings	0.41
Climate Benefits *	0.13
Health Benefits **	0.24
Total Benefits †	0.77
Consumer Incremental Product Costs ‡	0.19
Net Benefits	0.58
7% discount rate	
Consumer Operating Cost Savings	0.14
Climate Benefits * (3% discount rate)	0.13
Health Benefits **	0.07
Total Benefits †	0.35
Consumer Incremental Product Costs ‡	0.10
Net Benefits	0.24

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

[21] 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.2 of this document.

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

[23] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *Annual Energy Outlook 2022* (''*AEO2022*''). *AEO2022* represents current federal and state legislation and final implementation of regulations as of the time of its preparation. *See* section IV.K of this document for further discussion of *AEO2022* assumptions that effect air pollutant emissions.

[24] *See* Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates Under Executive Order 13990, Washington, DC, February 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

[25] DOE estimated the monetized value of SO_2 and NO_X emissions reductions associated with electricity savings using benefit per ton estimates from the EPA. *See* section IV.L.2 of this document for further discussion.

[26] 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.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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.69 for net benefits using all four SC–GHG estimates.

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

The benefits and costs of the proposed 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 the benefits of GHG and NO_X and SO_2 emission reductions, all annualized.[27] The national operating 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 2027–2056. The benefits associated with reduced emissions achieved as a result of the proposed standards are also calculated based on the lifetime of medium-voltage dry-type distribution transformers shipped in 2027–2056.

Estimates of annualized benefits and costs of the proposed standards are shown in Table I.10. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced NO_X and SO_2 emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $10.8 million per year in increased equipment costs, while the estimated annual benefits are $14.9 million in reduced equipment operating costs, $7.6 million in climate benefits, and $7.8 million in health benefits. The net benefit would amount to $19.5 million per year.

TABLE I.10—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS (TSL 2)

Category	Million (2021$/year)		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	23.3	22.2	25.8
Climate Benefits *	7.6	7.5	8.2
Health Benefits **	13.5	13.2	14.5
Total Benefits †	44.4	42.9	48.5
Consumer Incremental Product Costs ‡	11.0	11.7	10.7
Net Benefits	33.5	31.1	37.7
7% discount rate			
Consumer Operating Cost Savings	14.9	14.3	16.4
Climate Benefits * (3% discount rate)	7.6	7.5	8.2
Health Benefits **	7.8	7.6	8.3
Total Benefits †	30.3	29.4	32.9
Consumer Incremental Product Costs ‡	10.8	11.6	10.6
Net Benefits	19.5	17.9	22.2

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

[27] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2021, 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.,* 2030), and then discounted the present value from each year to 2021. 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.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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.69 for net benefits using all four SC–GHG estimates.

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

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

D. Conclusion

DOE has tentatively concluded that the proposed standards 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 achieving these standard levels are already commercially available for all product classes covered by this proposal. As for economic justification, DOE's analysis shows that for each equipment class the benefits of the proposed standards exceed the burdens of the proposed standards. Using a 7-percent discount rate for consumer benefits and costs and NO_X and SO_2 reduction benefits, and a 3-percent discount rate case for GHG social costs, the estimated annual cost of the proposed standards for distribution transformers is $652.5 million per year in increased distribution transformer costs, while the estimated annual benefits are $961.8 million in reduced distribution transformer operating costs, $664.2 million in climate benefits and $665.2 million in health benefits. The net benefit amounts to $1,638.7 million per year.

TABLE I.11—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AT PROPOSED STANDARD LEVELS

Category	Million (2021$/year)		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	1,528.9	1,426.0	1,647.0
Climate Benefits *	664.2	638.0	693.6
Health Benefits **	1,189.6	1,142.0	1,243.2
Total Benefits †	3,382.8	3,205.9	3,583.8
Consumer Incremental Product Costs ‡	659.8	689.4	632.6
Net Benefits	2,723.1	2,516.4	2,951.1
7% discount rate			
Consumer Operating Cost Savings	961.8	902.8	1,027.3
Climate Benefits * (3% discount rate)	664.2	638.0	693.6
Health Benefits **	665.2	640.4	691.8
Total Benefits †	2,291.3	2,181.2	2,412.7
Consumer Incremental Product Costs ‡	652.5	678.9	627.8
Net Benefits	1,638.7	1,502.5	1,784.9

Note: This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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.69 for net benefits using all four SC–GHG estimates.

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

TABLE I.12—SUMMARY OF MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AT PROPOSED STANDARD LEVELS

	Billion ($2021)
3% discount rate	
Consumer Operating Cost Savings	26.63
Climate Benefits *	11.56
Health Benefits **	20.72
Total Benefits †	58.91
Consumer Incremental Product Costs ‡	11.49
Net Benefits	47.42
7% discount rate	
Consumer Operating Cost Savings	9.11
Climate Benefits * (3% discount rate)	11.56
Health Benefits **	6.29
Total Benefits †	26.97
Consumer Incremental Product Costs ‡	6.17
Net Benefits	20.79

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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.69 for net benefits using all four SC–GHG estimates.

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

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.[28] For example, some covered products and equipment, including distribution transformers, have substantial 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 10.60 quad. Based on the amount of FFC savings, the corresponding reduction in GHG emissions, and need to confront the global climate crisis, DOE has initially determined the energy savings from the proposed standard levels are ''significant'' within the meaning of 42 U.S.C. 6295(o)(3)(B). A more detailed discussion of the basis for these tentative conclusions is contained in the remainder of this document and the accompanying TSD.

DOE also considered more-stringent energy efficiency levels as potential standards, and is still considering them in this rulemaking. However, DOE has tentatively concluded that the potential burdens of the more-stringent energy efficiency levels would outweigh the projected benefits.

Based on consideration of the public comments DOE receives in response to this document and related information collected and analyzed during the course of this rulemaking effort, DOE may adopt energy efficiency levels presented in this document that are either higher or lower than the proposed

[28] 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).

standards, or some combination of level(s) that incorporate the proposed standards in part.

II. Introduction

The following section briefly discusses the statutory authority underlying this proposed 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. Title III, Part B of EPCA (42 U.S.C. 6291–6309, as codified), established the Energy Conservation Program for ''Consumer Products Other Than Automobiles.'' Title III, Part C of EPCA (42 U.S.C. 6311–6317, as codified), 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 6 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(e)(1); 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 specifically include definitions (42 U.S.C. 6311; 42 U.S.C. 6291), test procedures (42 U.S.C. 6314; 42 U.S.C. 6293), labeling provisions (42 U.S.C. 6315; 42 U.S.C. 6294), energy conservation standards (42 U.S.C. 6313; 42 U.S.C. 6295), and the authority to require information and reports from manufacturers (42 U.S.C. 6316; 42 U.S.C. 6296).

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 (b); 42 U.S.C. 6297) DOE may, however, grant waivers of Federal preemption for particular State laws or regulations, in accordance with the procedures and other provisions set forth under 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 equipment. (42 U.S.C. 6316(a), 42 U.S.C. 6295(o)(3)(A) and 42 U.S.C. 6295(r)) Manufacturers of covered equipment must use the Federal test procedures as the basis for: (1) certifying to DOE that their equipment complies with the applicable energy conservation standards adopted pursuant to EPCA (42 U.S.C. 6316(a); 42 U.S.C. 6295(s)), and (2) making representations about the efficiency of that equipment (42 U.S.C. 6314(d)). Similarly, DOE must use these test procedures to determine whether the equipment complies with relevant standards promulgated under EPCA. (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 determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A) and 42 U.S.C. 6295(o)(3)(B)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6295(o)(3))

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 standard 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. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)) DOE must make this determination after receiving comments on the proposed standard, and by considering, to the greatest extent practicable, the following seven statutory factors:

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

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

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

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

(7) Other factors the Secretary of Energy (''Secretary'') considers relevant. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII))

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

B. Background

1. Current Standards

In a final rule published on April 18, 2013 (''April 2013 Standards Final Rule''), 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, Table II.3.

TABLE II.1—FEDERAL ENERGY CONSERVATION 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
		1,000	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	1,000	99.43
667	99.52	1,500	99.48
833	99.55	2,000	99.51
		2,500	99.52

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

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.1	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	

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

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
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	1,000	99.28	99.2	99.11
833	99.31	99.23	99.20	1,500	99.37	99.3	99.21
				2,000	99.43	99.36	99.28
				2,500	99.47	99.41	99.33

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, which announced the availability of its analysis for distribution transformers. 86 FR 48058 (''August 2021 Preliminary Analysis'') The purpose of the August 2021 Preliminary Analysis 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 technical support document (''TSD'') and accompanying analytical spreadsheets for the August 2021 Preliminary Analysis provided the analyses DOE undertook to examine the potential for amending energy conservation standards for distribution transformers and provided preliminary discussions in response to a number of issues raised by comments to the June 2019 Early Assessment Review RFI. It described the analytical methodology that DOE used, and each analysis DOE had performed.

On November 11, 2021, DOE published a notice reopening the comment period an additional 30 days. 86 FR 63318.

DOE received comments in response to the August 2021 Preliminary Analysis from the interested parties listed in Table II.4.

TABLE II.4—AUGUST 2021 PRELIMINARY ANALYSIS WRITTEN COMMENTS

Commenter(s)	Abbreviation	Docket No.	Commenter type
Electric Research and Manufacturing Cooperative, Inc	ERMCO	45	Manufacturer.
Powersmiths, Inc	Powersmiths	46	Manufacturer.
Copper Development Association	CDA	47	Trade Organization.
Schneider Electric	Schneider	49	Manufacturer.
National Electrical Manufacturers Association	NEMA	50	Trade Organization.
Northwest Energy Efficiency Alliance	NEEA	51	Efficiency Organization.
Appliance Standards Awareness Project, American Council for an Energy-Efficient Economy, Natural Resources Defense Council.	Efficiency Advocates	52	Efficiency Organization.
Metglas, Inc	Metglas	53	Steel Manufacturer.
Carte International, Inc	Carte	54	Manufacturer.
Eaton Corporation	Eaton	55	Manufacturer.
Edison Electric Institute	EEI	56	Utilities.
Cleveland-Cliffs Steel Corporation	Cliffs	57	Steel Manufacturer.
Greenville Electric Utility System	GEUS	58	Utilities.
Howard Industries, Inc	Howard	59	Manufacturer.

A parenthetical reference at the end of a comment quotation or paraphrase provides the location of the item in the public record.[29]

[29] 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).

C. Deviation From Appendix A

In accordance with section 3(a) of 10 CFR part 430, subpart C, appendix A (''appendix A''), DOE notes that it is deviating from the provision in appendix A regarding the NOPR stage for an energy conservation standard rulemaking. Section 6(f)(2) of appendix A specifies that the length of the public comment period for a NOPR will vary depending upon the circumstances of the particular rulemaking, but will not be less than 75 calendar days. For this NOPR, DOE is providing a 60-day comment period, as required by EPCA. 42 U.S.C. 6316(a); 42 U.S.C. 6295(p). As stated previously, DOE requested comment in the June 2019 Early Assessment Review RFI on the technical and economic analyses and provided stakeholders a 45-day comment period. 84 FR 28239. Additionally, DOE provided a 75-day comment period for the August 2021 Preliminary Analysis. 86 FR 48058. DOE also reopened the comment period for the August 2021 Preliminary Analysis for an additional 30-days. 86 FR 63318. DOE has relied on many of the same analytical assumptions and approaches as used in the preliminary assessment presented in the TSD. Therefore, DOE believes a 60-day comment period is appropriate and will provide interested parties with a meaningful opportunity to comment on the proposed rule.

III. General Discussion

DOE developed this proposal after considering oral and written comments, data, and information from interested parties that represent a variety of interests. The following discussion addresses issues raised by these commenters.

A. Equipment Classes and Scope of Coverage

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 differing standards. In making a determination whether a performance-related feature justifies a different standard, DOE must consider such factors as 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 proposed rule are discussed in further detail in section IV.A.2 of this document. This proposed 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, nonventilated transformer, rectified 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

The scope of coverage of this proposed rule is discussed in further detail in section IV.A.1 of this document.

B. 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 products must use these test procedures to certify to DOE that their product complies with energy conservation standards and to quantify the efficiency of their product. DOE's current energy conservation standards for distribution transformers are expressed in terms of percentage efficiency at rated per-unit load (PUL). (*See* 10 CFR 431.193; 10 CFR part 431, subpart K, appendix A (''appendix A'').)

On September 14, 2021, DOE published a test procedure final rule for distribution transformers that 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. 89 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. *Id.* at 89 FR 51249.

C. Technological Feasibility

1. General

In each energy conservation standards rulemaking, DOE conducts a screening analysis based on information gathered on all current technology options and prototype designs that could improve the efficiency of the products or equipment that are the subject of the rulemaking. As the first step in such an analysis, DOE develops a list of technology options for consideration in consultation with manufacturers, design engineers, and other interested parties. DOE then determines which of those means for improving efficiency are technologically feasible. DOE considers technologies incorporated in commercially available products or in working prototypes to be technologically feasible. 10 CFR 431.4; 10 CFR part 430, subpart C, appendix A, sections 6(b)(3)(i) and 7(b)(1) (''Process Rule'').

After DOE has determined that particular technology options are technologically feasible, it further evaluates each technology 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; Sections 6(c)(3)(ii)–(v) and 7(b)(2)–(5) of the Process Rule. Section IV.B of this document discusses the results of the screening analysis for distribution transformers, particularly the designs DOE considered, those it screened out, and those that are the basis for the standards considered in this proposed rule. For further details on the screening analysis for this proposed rule, see chapter 4 of the NOPR technical support document (''TSD'').

2. Maximum Technologically Feasible Levels

When DOE proposes to adopt an amended standard for a type or class of covered product, it must determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible for such product. (42 U.S.C. 6316(a); 42 U.S.C. 6295(p)(1)) Accordingly, in the engineering analysis, DOE determined the maximum technologically feasible (''max-tech'') improvements in energy efficiency for distribution transformers, using the design parameters for the most efficient products available on the market or in working prototypes. The max-tech levels that DOE determined for this rulemaking are described in section IV.C.2.e of this proposed rule and in chapter 5 of the NOPR TSD.

D. Energy Savings

1. Determination of Savings

For each trial standard level (''TSL''), DOE projected energy savings from application of the TSL to distribution transformer purchased in the 30-year period that begins in the year of compliance with the proposed standards (2027–2056).[30] The savings are measured over the entire lifetime of distribution transformers purchased in the previous 30-year period.[31] DOE

[30] Each TSL is composed of specific efficiency levels for each product class. The TSLs considered for this NOPR are described in section V.A of this document. DOE conducted a sensitivity analysis that considers impacts for products shipped in a 9-year period.

[31] Savings are determined for equipment shipped over the 30-year analysis period of 2027 through

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'') model to estimate national energy savings (''NES'') from potential amended or new standards for distribution transformers. The NIA 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. 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.[32] 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.[33] 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. Based on the amount of FFC savings, the corresponding reduction in emissions, and need to confront the global climate crisis, DOE has initially determined the energy savings from the proposed standard levels are ''significant'' within the meaning of 42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B).

E. 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 a potential amended standard on manufacturers, DOE conducts an MIA, as discussed in section IV.J of this document. 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 expense (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 products 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 of this document.

2056. Distribution transformers have a maximum lifetime of 60 years; therefore savings are determined for equipment that survive, and accrue savings through 2115.

[32] 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).

[33] 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 12, 2021 (86 FR 70892, 70906).

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 III.D of this document, DOE uses the NIA models to project national energy savings.

d. Lessening of Utility or Performance of Products

In establishing product 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 products. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(IV)) Based on data available to DOE, the standards proposed in this document would not reduce the utility or performance of the products 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 proposed 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 proposed standard and to transmit such determination to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(ii)) DOE will transmit a copy of this proposed rule to the Attorney General with a request that the Department of Justice (''DOJ'') provide its determination on this issue. DOE will publish and respond to the Attorney General's determination in the final rule. DOE invites comment from the public regarding the competitive impacts that are likely to result from this proposed rule. In addition, stakeholders may also provide comments separately to DOJ regarding these potential impacts. See the **ADDRESSES** section for information to send comments to DOJ.

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 proposed 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 proposed standards are likely to result in environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases (''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; 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

As set forth in 42 U.S.C. 6295(o)(2)(B)(iii), EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the consumer of a product 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. DOE's LCC and PBP analyses generate values used to calculate the effects that proposed energy conservation standards would have on the payback period for consumers. These analyses include, but are not limited to, the 3-year payback period 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 proposed 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 proposed in this document. The first tool is a model that calculates the LCC savings and PBP of potential amended or new energy conservation standards. The national impacts analysis uses a second model 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 tools are available in the docket for this rulemaking: *www.regulations.gov/docket/EERE-2019-T-STD-0018.* Additionally, DOE used output from the latest version of the Energy Information Administration's (''EIA's'') *Annual Energy Outlook* (''*AEO*''), a widely known energy projection for the United States, 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 NOPR 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) 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.

DOE received several comments regarding the definition of ''distribution transformer'' and the definitions of equipment excluded from the definition. 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)) In response to comments received as part of the June 2019 Early Assessment Review RFI that suggested DOE include ''low-voltage autotransformers'' within the scope of distribution transformers, DOE noted that autotransformers do not provide galvanic isolation [34] and thus would be unlikely to be used in at least some general-purpose applications. (August 2021 Preliminary Analysis TSD at p. 2–5) In the August 2021 Preliminary Analysis TSD, DOE requested comment regarding the potential use of autotransformers as substitutes for general-purpose distribution transformers. *Id.*

Schneider commented that while voltage conversion can be done with an autotransformer, autotransformers cannot derive a neutral, lower source impedance, or phase shift to remove triplen (*i.e.,* multiples-of-three) harmonics, meaning an autotransformer risks sacrificing power quality if used in place of a general-purpose distribution transformer. (Schneider, No. 59 at p. 2) Schneider added that because of these power quality concerns, autotransformers would be unlikely to be used in commercial buildings but could be used in some subsegments and smaller commercial jobs—a possibility supported by manufacturers' adding autotransformers to standard product catalogs. (Schneider, No. 49 at p. 2) Schneider commented that it recommends autotransformers in subsegments that require wye-wye connections [35] and that segment is growing and will continue to grow if autotransformers remain exempt. (Schneider, No. 49 at p. 2) Schneider commented that that are no technical limitations for autotransformer to meet standards and asserted that the exclusion was related to how efficiency was calculated and tested. Schneider recommended subjecting them to the current efficiency standards based on their nameplate kVA. (Schneider, No. 49 at pp. 2–3) Schneider commented that in typical applications (*i.e.,* 480Y/277 and 208Y/120) autotransformers would be 60 percent the size and 20–25 percent less expensive. In non-typical applications, units would be 20 percent the size and 50 percent less expensive. (Schneider, No. 49 at p. 3)

NEMA commented that it is not aware of autotransformers being used in place of distribution transformers. (NEMA, No. 50 at p. 3)

Stakeholder comments suggest that there may be certain applications in which an autotransformer may be substitutable for an isolation transformer. However, the comments also suggest such substitution is limited to specific applications (*e.g.,* wye-wye connections) and not common enough to be regarded as general practice. Further, DOE did not receive any feedback counter to its statement in the August 2021 Preliminary Analysis TSD that autotransformers do not provide galvanic isolation and thus would be unlikely to be used in at least some general-purpose applications. Based on this feedback, DOE is not proposing to amend the exclusion of autotransformers under the distribution transformer definition. DOE will monitor the market and may reevaluate this exclusion if evidence exists to support growing use of autotransformers based on lower purchase price than would be warranted by technical considerations alone.

b. Drive (Isolation) Transformers

In the August 2021 Preliminary Analysis TSD, DOE noted that the EPCA definition of distribution transformers 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 a drive transformer. (42 U.S.C. 6291(35)(b)(ii)) DOE stated that it did not have any data indicating that ''drive isolation transformers'' were being widely used in generally purpose applications and as such, considered them statutorily excluded. DOE requested comment and data as to the extent to which ''drive isolation transformers'' are used in generally purpose applications. (August 2021 Preliminary Analysis TSD at p. 2–6)

Schneider and Eaton commented that drive isolation transformers have historically been sold with nonstandard low-voltage ratings, corresponding to typical motor input voltages, and as such are unlikely to be used in general-purpose applications. (Schneider, No. 49 at p. 3; Eaton, No. 55 at p. 3) NEMA commented that drive isolation transformers are not sold in great quantities and not widely used in general purpose applications. (NEMA, No. 50 at p. 3)

Schneider and Eaton commented that recently there has been some 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 are being used in general distribution applications. (Schneider No. 49 at p. 3; Eaton, No. 55 at p. 3) Schneider commented that only 6-pulse drive isolation transformers [36] can serve

[34] *i.e.,* autotransformers contain a continuous, current-carrying electrical pathway that ''isolation'' transformers do not, which is perceived as a safety compromise in some applications.

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

[36] Drive-isolation transformers employ rectifier diodes to mitigate drive harmonics by phase shifting secondary voltages. The rectifier diode results in two pulses per phase. In a standard three-phase, drive-isolation transformer, application of a rectifier would result in 6-pulses, two per 120° phase shift. If additional harmonic mitigation is needed, additional secondary windings are added with differing connections phase shifted from one

Continued

general purpose applications. (Schneider, No. 49 at p. 4) Eaton added that there is a minor concern that consumers will increasingly discover that drive isolation transformers can be used in certain general-purpose applications, putting manufacturers in the position of suspecting but not being able to ascertain circumvention without being sure of end use. (Eaton, No. 55 at p. 3) Eaton commented that a DOE compliant general-purpose transformer would be 16 percent more expensive than a drive isolation transformer that could be used in its place, while the losses for the drive isolation transformer at 50 percent PUL were 55 percent greater. (Eaton, No. 55 at p. 3)

Eaton commented that pulse count is somewhat hard to define as it is generally more a function of the rectifier that the drive isolation transformer is connected to than the transformer itself. (Eaton, No. 55 at p. 4) Eaton added that 12-pulse and 24-pulse drive isolation transformers could, technically, be used in general purpose applications but that it would be less likely due to higher cost. (Eaton, No. 55 at p. 3–4)

Schneider commented that 6-pulse drive isolation transformers should be included in the LVDT scope, as is required in Canada. (Schneider, No. 49 at p. 4)

Commenters indicated that while some drive isolation transformers could, in theory be used in general purpose applications, no evidence exists suggesting this practice is common. As such, DOE has concluded that drive isolation transformers remain an example of a transformer that is designed to be used in special purpose applications and is unlikely to be used in general purpose applications. Given that drive isolation transformers are excluded by statute, including drive isolation transformers would first require a finding that they are being used in general purpose applications, which does not appear to be the case at this time.

Schneider commented that drive isolation transformers should only be permitted at standard motor voltages and not standard distribution voltages. (Schneider, No. 49 at p. 3)

DOE tentatively finds, as supported by comments from Schneider and Eaton, that certain distribution transformers that meet the current criteria of a ''drive isolation transformers'' are likely to be used in general-purpose applications based on their voltage rating. The overwhelming majority of equipment in the US is designed to operate using either 208Y/120 or 480Y/277 voltage, and therefore the overwhelming majority of general-purpose distribution transformers have a secondary voltage rating that is one of these standard voltage ratings. Drive-isolation transformers, by contrast, are not designed to power the majority of equipment. Rather, they are designed to work with a specific motor drive to output a special purpose voltage, unique to the application. As such, drive-isolation transformers with a rated secondary voltage of 208Y/120 or 480Y/277 is considerably more likely to be used in general purpose applications rather than special purpose applications.

EPCA excludes from the definition of distribution transformer certain transformers designed to be used in an application other than a general-purpose application. Specifically, ''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 a drive transformer, rectifier transformer, auto-transformer, Uninterruptible Power System transformer, impedance transformer, regulating transformer, sealed and nonventilating transformer, machine tool transformer, welding transformer, grounding transformer, or testing transformer[.]'' (42 U.S.C. 6291(35)(b)(ii))

Drive (isolation) transformers are defined 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 additional mechanical stresses resulting from an alternating current adjustable frequency motor drive or a direct current motor drive.'' 10 CFR 431.192. In the product catalogs reviewed by DOE, drive-isolation transformers are frequently listed at common motor voltages such as ''460Y/266'' and ''230Y/133.''. The listing at common motor voltages indicates that these drive-isolation transformers are designed for use in special purpose applications (*i.e.,* isolating an electric motor from the line) and are unlikely to be used in general purpose distribution applications, on account of not aligning with general distribution voltages.

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). To the extent that some transformers are marketed as drive-isolation transformers but with rated output voltages aligning with common distribution voltages, DOE is unable to similarly conclude that these transformers are used in special purpose applications. Comments by Eaton and Schneider confirm that while these transformers are not sold in great numbers, they are significantly more likely to be used in general purpose distribution applications. As such, DOE has tentatively determined that such distribution transformers are not drive (isolation) transformers as that term applies to the exclusions from the definition of ''distribution transformer.''

In order to limit the definition of drive isolation transformers to distribution transformers designed for use in special purpose applications and not likely to be used in general purpose applications, DOE proposes to amend the definition to include the criterion that drive isolation transformers have an output voltage other than 208Y/120 or 480Y/277. DOE may consider additional voltage limitations in the definition of ''drive isolation transformer'' should DOE determine such voltages indicate a design for use in general purpose applications.

DOE requests comment on the proposed amendment to the definition of drive (isolation) transformer. DOE requests comment on its tentative determination that voltage ratings of 208Y/120 and 480Y/277 indicate a design for use in general purpose applications. DOE also requests comment on other voltage ratings or other characteristics that would indicate a design for use in general purpose applications.

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 August 2021 Preliminary Analysis TSD, DOE requested feedback as to the number of nonstandard kVA transformers sold and how manufacturers are currently interpreting the normal impedance range for nonstandard kVA values. (August 2021 Preliminary Analysis TSD at p. 2–8)

NEMA and Eaton recommended that the impedance values in Tables 1 and 2 of 10 CFR 431.192 under the definition of ''special-impedance transformer'' be

another. Manufacturers' sell drive-isolation transformers as 6-pulse, 12-pulse, or 24-pulse.

listed as a kVA range, to remove what they stated is an ambiguity as to the normal impedance of non-standard transformer capacities (*i.e.,* capacities not explicitly included in the tables). (Eaton, No. 55 at p. 4; NEMA, No. 50 at p. 3–4) Eaton commented that there were very few nonstandard kVA ratings for single-phase transformers and just under one percent of three-phase transformers are rated for non-standard kVAs. (Eaton, No. 55 at p. 4) Eaton added that nonstandard kVAs are quite common in the currently exempted step-up transformers, making up 27 percent of three-phase step-up transformers. (Eaton, No. 55 at p. 4) Eaton stated that it currently uses the impedance values of the adjacent standard kVA ratings that result in the largest normal impedance range and, equivalently, the narrowest excluded impedance range. (Eaton, No. 55 at p. 5)

NEMA commented that many, but not all, customers specify the middle of the normal impedance range. NEMA stated that some customers specify a particular impedance to compliment an application, such as for protection equipment or to match better with sensitive loads. (NEMA, No. 50 at p. 4)

Schneider commented that it receives few requests for distribution transformers outside the normal impedance range and few requests for distribution transformers with nonstandard kVAs and therefore applied energy efficiency regulations to special impedance transformers without pursuing exemptions. (Schneider, No. 49 at p. 4) Schneider added that the special impedance exemption could potentially be removed, and thus reduce potential abuse or the normal range could be expanded for all distribution transformers, regardless of kVA to be from 0.5 percent to 15 percent. (Schneider, No. 49 at p. 4) As another alternative, Schneider recommended either setting the mid-range impedance as a threshold or using a linear interpolation of the impedance values immediately above and below that kVA rating, similar to how efficiency standards are applied for non-standard kVA ratings. (Schneider, No. 49 at p. 4–5)

As DOE noted in the August 2021 Preliminary Analysis TSD, its current values for normal impedance are based on NEMA TP 2–2005. (August 2021 Preliminary Analysis TSD at p. 2–8) The current tables in the ''special-impedance transformer'' definition do not explicitly address how to treat nonstandard kVA values.

DOE is proposing 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.''. This proposed approach is consistent with the recommendation from Schneider. Moreover, this approach is consistent with the approach specified for determining the required efficiency requirements of distribution transformers of nonstandard kVA rating (*i.e.,* using a linear interpolation from the nearest bounding kVA values listed in the table). *See* 10 CFR 431.196.

DOE requests comment on its proposed amendment to the definition of ''special-impedance transformer'' and whether it provides sufficient clarity as to how to treat the normal impedance ranges for non-standard kVA distribution transformers.

Carte commented that one of its customers requires higher impedance pole transformers, within the ''normal'' range, but in general the larger coils and higher core losses associated with a higher impedance can be disadvantaged in meeting efficiency standards. (Carte, No. 54 at p. 1)

DOE relies on the current definition of ''special-impedance transformer'' in its engineering analysis. DOE does not further consider impedance aside from ensuring selectable models in the analysis are within the ''normal impedance'' range as currently defined. DOE's analyzed higher efficiency levels, including those using amorphous steel, span a range of impedance values and therefore DOE has not considered further separating distribution transformers based on impedance.

d. Tap Range of 20 Percent or More

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 August 2021 Preliminary Analysis TSD, DOE requested comment as to whether only full-power taps should count toward the exclusion and how the choice of nominal voltage would impact the exclusion. (August 2021 Preliminary Analysis TSD at p. 2–9)

In response, Schneider, NEMA and Eaton commented 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)

Eaton commented that nominal voltage is selected by the consumer but selecting one such that it excludes a product can result in 17 percent lower costs and 73 percent higher losses at 50 percent PUL. (Eaton, No. 55 at p. 6) Schneider provided an example of how the nominal voltage can impact whether a product is subject to standards. (Schneider, No. 49 at p. 6) Eaton commented that of the three-phase units it has built, only one unit was built as having a tap range of 20 percent or more while 112 units were built as DOE compliant but could be moved out of scope based on the choice of nominal voltage. (Eaton, No. 55 at pp. 6–7) Schneider added that another complication to using nominal voltage is a new type of distribution transformer that has multiple-nominal voltages. (Schneider, No. 49 at p. 6–8)

Eaton supported changing how the tap range is calculated to remove potential incentives to circumvent standards. (Eaton, No. 55 at p. 6) NEMA commented that it did not reach consensus as to how to calculate tap range. (NEMA, No. 50 at p. 4) Schneider recommended DOE establish all common system voltages as nominal and have manufacturers justify tap ranges according to the relative function of each to the associated nominal in the case of multiple nominals. (Schneider, No. 49 at p. 8) Schneider added that if it is too difficult to establish what nominal should be, the 20 percent tap range exclusion could be removed. (Schneider, No. 49 at p. 8)

While the traditional industry understanding of tap range is in percentages relative to the nominal voltage, stakeholder comments suggest that such a calculation can be applied differently by different manufacturers such that two physically identical distribution transformers can be inside or outside of scope depending on the choice of nominal voltage. To have a consistent standard for physically identical distribution transformers, DOE proposes 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. The amended definition would classify transformers with tap ranges of 20 percent or more as ''a transformer with multiple full-power voltage taps, the highest of which equals at least 20 percent more than the lowest, computed based on the sum of the deviations of these taps from the transformer's maximum full-power voltage.''. Such a modification would ensure that all distribution transformers capable of operating across a similar voltage range, regardless of what voltage is considered nominal, are treated equally. Further, the proposed modification removes ambiguity as to what customers are using as a nominal voltage and removes incentives to change the nominal voltage to move equipment into or out of scope of the standards.

DOE requests comment on its proposed definition for transformers with a tap range of 20 percent or more.

e. Sealed and Nonventilated Transformers

As discussed, 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 a ''sealed and nonventilating transformers.'' (42 U.S.C. 6291(35)(b)(ii)) In the August 2021 Preliminary Analysis TSD, DOE noted that the definition of sealed and nonventilating transformers is applicable only to dry-type transformers. While liquid-immersed transformers are technically also sealed, DOE has explicitly included them in the definition of a distribution transformer. 10 CFR 431.92. (August 2021 Preliminary Analysis TSD at p. 2–7)

In response, NEMA recommended DOE add the words ''dry-type'' to the definition of sealed and nonventilated transformers. (NEMA, No. 50 at p. 3)

DOE agrees that the proposed clarification would help clarify the scope of the sealed and nonventilated transformer exclusion and has proposed to amend the definition as such.

DOE requests comment on its proposed amendments to the definitions of sealed and nonventilated transformers.

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, and 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))

DOE has acknowledged 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. 78 FR 2336, 23354. However, DOE previously had not identified this as a widespread practice. *Id.* In the August 2021 Preliminary Analysis TSD, DOE requested feedback as to what the typical efficiency is of step-up transformers, what fraction are being used in traditional distribution transformer applications, and what are the typical input and output voltages of step-up transformers. (August 2021 Preliminary Analysis TSD at p. 2–18)

NEMA commented that efficiency of step-up transformers is dictated by customers and is sometimes above and sometimes below DOE efficiency levels for distribution transformers. NEMA added that they are not aware of step-up transformers being used in distribution applications and they are concerned that subjecting step-up transformers to regulation may negatively constrain design flexibility. (NEMA, No. 50 at p. 5)

Eaton commented that step-up transformers are almost exclusively used in renewable energy applications where low-voltages (typically less than 700 volts) are stepped up to medium-voltage distribution applications (typically up to 34.5 kV). Eaton added that virtually all step-up transformers are three-phase and there are maybe a dozen single-phase step-up transformers per year which may or may not be possible circumvention scenarios. (Eaton, No. 55 at p. 9) Eaton commented that some step-up transformer customers specify total owning cost, maximum losses, or efficiency and provided a table of average efficiency of three-phase liquid-immersed step-up transformers which showed the average efficiency of step-up transformers tended to be below DOE efficiency standards. (Eaton, No. 55 at p. 9) Eaton noted that many solar photovoltaic inverter manufacturers have been using higher input voltages that often require non-standard voltages or winding configurations and may decrease likelihood of a step-up transformer being used in a distribution application. (Eaton, No. 55 at p. 9) Eaton stated that 31 percent of their three-phase step-up transformers had common distribution low-voltages, that could more easily be used in distribution applications, but Eaton had no knowledge that step-up transformers were being used in traditional distribution applications. (Eaton, No. 55 at p. 9) Eaton stated that step-up voltages with common distribution high and low-voltages could possibly be operated in reverse in distribution transformer applications. (Eaton, No. 55 at p. 9)

The comments received support DOE's prior statements. While step-up transformers could, in theory, be used in distribution applications, DOE does not have any data to indicate that this is a common or widespread practice. Eaton's comments underscore that step-up transformers serve a separate and unique application, often in the renewable energy field where transformers designs may not be optimized for the distribution market but rather are optimized for integration with other equipment, such as inverters. Therefore, DOE is not proposing to amend the definition of ''distribution transformer'' to account for step-up transformers. DOE may reevaluate this conclusion in a future action if evidence arises to suggest step-up transformers are being used in distribution functions.

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 uninterruptable 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, and counteracts such irregularities. 69 FR 45376, 45383. DOE has clarified that uninterruptable power supply transformers do not ''supply power to'' an uninterruptible power system, rather they are ''used within'' the uninterruptible power system. 72 FR 58190, 58204. This is consistent with the reference in the definition to transformers that are ''within'' the uninterruptible power system. 10 CFR 431.192. Distribution transformers at the input, output or bypass that are supplying power to the uninterruptible power system are not uninterruptable power supply transformers.

In the August 2021 Preliminary Analysis TSD, DOE requested comment regarding how manufacturers are applying the definition of uninterruptable power supply transformer and whether amendments are needed. (August 2021 Preliminary Analysis TSD at p. 2–10)

In response, NEMA commented that manufacturers are applying the definition appropriately and clarification is not needed. (NEMA, No. 50 at p. 4) Schneider recommended DOE explicitly state that transformers at the input, output, or by-pass of an uninterruptible power system are not part of the uninterruptible power system and as such are not excluded. (Schneider, No. 49 at p. 8).

DOE agrees that explicitly stating that transformers at the input, output, or bypass of a distribution transformer are not a part of the uninterruptable power system would further clarify the definition. As such, DOE is proposing to amend the definition to make these clarifications.

DOE requests comment on its proposed amendment to the definition of uninterruptable power supply transformers.

Carte asked if network transformers are considered uninterruptible power supply transformers as the network grid cannot go down. (Carte, No. 54 at p. 2) DOE notes that the need for a reliable operation does not make a distribution transformer an uninterruptible power supply transformer. As stated, uninterruptible power supply transformers are used within uninterruptable power systems as a power conditioning device, not as a distribution 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[37] 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 has previously stated that the definition of distribution transformer applies to transformers having an output voltage of 600 volts or less, not having only an output voltage of less than 600 volts. 78 FR 23336, 23353. For example, a three-phase transformer for which the wye connection is at or below 600 volts, but the delta connection is above 600 volts 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.*

Eaton commented that DOE flipped the usage of wye and delta in its example where one voltage complies and the other does not because wye voltage should be less than delta voltage. (Eaton, No. 55 at p. 8) DOE has updated its language above to correct this.

Schneider commented that the industry interpretation of input and output voltage is likely line voltage but using phase encompasses a larger scope and DOE should clarify in the regulatory text. (Schneider, No. 49 at p. 8) NEMA commented that DOE should clarify the interpretation of voltage in the regulatory text. (NEMA, No. 50 at p. 4) Eaton commented that using phase voltage would deviate from industry convention, but if DOE is choosing to interpret language this way, it should explicitly say so in the regulatory text. (Eaton, No. 55 at pp. 7–8)

DOE notes 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. 42 U.S.C. 6291(35). DOE has previously stated that a distribution transformer is required to comply if either line or phase voltage is within the scope of the distribution transformer definition. 78 FR 23336, 23353. Upon further evaluation, DOE notes that the distribution transformer input voltage limitation aligns with the common maximum distribution circuit voltage of 34.5 kV.[38 39] This common distribution voltage aligns with the distribution line voltage and implies that the intended definition of distribution transformer in EPCA was to specify the input and output voltages based on the line voltage. DOE has 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. For example, a transformer with a line voltage of 46 kV, which is commonly considered in industry to be a subtransmission voltage (*i.e.,* higher than a distribution voltage), would have a phase voltage less than 34.5 kV if sold in a wye-connection. Despite this transformer not being considered a distribution transformer by industry, interpreting DOE's definition as either a line or phase voltage would mean that a 46 kV wye-connection is considered a distribution transformer. As noted by stakeholders, such an interpretation would be out of step with common industry practice and out of step with the intended coverage of EPCA.

DOE notes 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. In this NOPR, DOE is proposing 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. This amendment, while a slight reinterpretation relative to the April 2013 Standards Final Rule, better aligns with industry practice, minimizes confusion, and does not impact any of the commonly built distribution transformer designs.

DOE requests comment as to whether its proposed definition better aligns with industries understanding on input and output voltages.

Further, DOE requests comment and data on whether the proposed amendment would impact products that are serving distribution applications, and if so, the number of distribution transformers impacted by the proposed amendment.

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

[38] 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.*

[39] 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.*

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, 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 definitions 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.* However, DOE further stated the inclusion of capacity limitations in the definition of ''distribution transformers'' in 10 CFR 431.192 does not mean that DOE has concluded that the EPCA definition of ''distribution transformer'' includes such limitations and stated that DOE intends to evaluate larger and smaller capacities than those included in the definition. *Id.*

DOE's current definition of distribution transformer specifies a capacity of 10 kVA to 2,500 kVA for liquid-immersed units and 15 kVA to 2,500 kVA for dry-type units. 10 CFR 431.192. The kVA ranges are consistent with NEMA publications in place at the time DOE adopted the range, specifically 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 23336, 23352. Subsequent to the April 2013 Standards Final Rule, establishing the current energy conservation standards, NEMA TP–1 standard was rescinded.

As noted above, the voltage limitations included in EPCA practically limit the size of distribution transformers. However, several industry sources suggest that those limitations may be greater than the current 2,500 kVA limit included in DOE's definition in 10 CFR 431.192. For example, Natural Resources Canada (''NRCAN'') regulations include three-phase dry-type distribution transformers with a nominal power of 15 to 7,500 kVA.[40] The European Union (''EU'') Ecodesign requirements specify maximum load losses and maximum no-load losses for three-phase liquid-immersed distribution transformers up to 3,150 kVA.[41] IEEE C57.12.90 and C57.12.91 cite similar short circuit tests for three-phase distribution transformers up to 5,000 kVA.

In the August 2021 Preliminary Analysis TSD, DOE requested comment regarding the quantity and efficiency of distribution transformers outside of the kVA range of the definition of distribution transformer but with input and output voltages that meet the voltage criteria in said definition. (August 2021 Preliminary Analysis TSD at p. 2–11)

Regarding dry-type distribution transformers, Schneider commented that units below 15 kVA are typically sealed or non-ventilated and as such would be excluded from the definition of distribution transformers. (Schneider, No. 49 at p. 9) Eaton commented that single-phase liquid immersed distribution transformers less than 10 kVA were less than 1 percent of shipments. (Eaton, No. 55 at p. 8)

DOE has not received any data or information suggesting that expanding the scope of the standards below 10 kVA for liquid-immersed distribution transformers or below 15 kVA for dry-type distribution transformers would lead to significant energy savings. As such, DOE is not proposing any changes to the lower capacity limit in the distribution transformer definition.

Regarding sales of distribution transformers beyond the 2,500 kVA scope, NEMA commented that while there are sales of models over 2,500 kVA, they are not sold in significant numbers as compared to in-scope products and energy savings would be limited. (NEMA, No. 50 at p. 5) Eaton commented that 19.6 percent of their three-phase liquid-immersed transformers have input and output voltage in-scope, but kVAs above 2500 kVA. (Eaton, No. 55 at p. 8) Eaton provided average efficiencies for these larger kVA distribution transformers. (Eaton, No. 55 at p. 8) In interviews, manufacturers commented that many of the larger distribution transformers are serving renewable applications as step-up transformers and would therefore be outside the scope of the standards regardless of the upper capacity of the definition of distribution transformer.

However, while many larger transformers may be step-up transformers, stakeholder comments suggest that there are also general purpose distribution transformers sold above 2,500 kVA with primary and secondary voltages that would still be within the criteria of the definition of distribution transformer. While NEMA suggested sales of models above 2,500 kVA are small, Eaton's comments suggest that at least for some manufacturers or markets they could be notable. Further, some manufacturers in interviews expressed concern 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).

As such, it is appropriate for DOE to consider all distribution transformers that are serving general purpose distribution applications, even if the capacity of those distribution transformers is larger than the common unit. DOE is considering multiple possible upper limits for distribution transformer capacity. IEEE C57.12.00–2015 lists the next three preferred continuous kVA ratings above 2,500 kVA as 3,750 kVA, 5,000 kVA, and 7,500 kVA. Eaton's comments suggest that the upper end of their distribution capacity is 3,750 kVA. In a prior rulemaking, stakeholders commented that their product lines include medium voltage dry-type models up to around 5,000 kVA.[42] Further, NRCAN regulations cover dry-type distribution transformers up to 7,500 kVA but exclude distribution transformers with low-voltage line currents of 4,000 amps or more.

Taken together, these points suggest there are some sales of general purpose distribution transformers above 2,500 kVA, such as at 3,750 kVA and 5,000kVA. DOE does not have any data or evidence that general purpose distribution transformers are being sold above 5,000 kVA and does have prior public comment of 5,000 kVA transformers with distribution voltages being sold. Therefore, DOE is proposing to expand the scope of the definition of ''distribution transformer'' in 10 CFR 431.192 for both liquid-immersed distribution transformers and dry-type distribution transformers to include distribution transformers up to 5,000 kVA. DOE is also considering other upper limits on the scope of distribution transformer, including 3,750 kVA and 7,500 kVA.

DOE requests comment and data as to whether 5,000 kVA represents the upper end of what is considered distribution

[40] See NRCAN dry-type transformer energy efficiency regulations at *www.nrcan.gc.ca/energy-efficiency/energy-efficiency-regulations/guide-canadas-energy-efficiency-regulations/dry-type-transformers/6875.*

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

[42] *See* Federal Pacific comment on Docket No. EERE–2006–STD–0099–0105. Available at *www.regulations.gov/comment/EERE-2006-STD-0099-0105.*

transformers or if another value should be used.

DOE has also estimated potential energy savings associated with expanding coverage of distribution transformers between 2,500 and 5,000 kVA within scope. DOE relied on public comments and confidential data sources to estimate shipments between 2,500 kVA and 5,000 kVA. Further, DOE has scaled its engineering analysis to encompass these larger units. Although the number of units shipped is estimated to represent a fraction of a percentage of total covered shipments, DOE has designed these scaled models as new representative units on account of starting from an unregulated baseline, as compared to the rest of the market, for which the baseline transformer complies with existing energy conservation standards. For liquid-immersed distribution transformers, representative unit 17 corresponds to a three-phase 3,750 kVA unit. For medium-voltage dry-type distribution transformers, representative units 18 and 19 correspond to a three-phase 3,750 kVA unit with a BIL of 46–95 kV and greater than 96 kV, respectively.

DOE has estimated the distribution transformer efficiency by assuming these out-of-scope units are purchased based on lowest first cost and would rely on similar grades of electrical steel as the distribution transformers that are currently in-scope units but would not currently be meeting any efficiency standard.

DOE requests comment and data as to the number of shipments of three-phase, liquid-immersed, distribution transformers greater than 2,500 kVA that would meet the in-scope voltage limitations and the distribution of efficiencies of those units.

DOE requests comment and data as to the number of shipments of three-phase, dry-type, distribution transformers greater than 2,500 kVA that would meet the in-scope voltage limitations and the distribution of efficiencies of those units.

2. Equipment Classes

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

Eleven equipment classes are established under the existing standards for distribution transformers, one of which (mining transformers [43]) 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 II.1 presents the eleven equipment classes that exist in the current energy conservation standards and provides the kVA range associated with each.

TABLE IV.1—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	20–45 kV BIL	15–833 kVA
EC6	Dry-Type	Medium	Three	20–45 kV BIL	15–2500 kVA
EC7	Dry-Type	Medium	Single	46–95 kV BIL	15–833 kVA
EC8	Dry-Type	Medium	Three	46–95 kV BIL	15–2500 kVA
EC9	Dry-Type	Medium	Single	≥96 kV BIL	75–833 kVA
EC10	Dry-Type	Medium	Three	≥96 kV BIL	225–2500 kVA
EC11	Mining Transformers				

* EC = Equipment Class.

In the August 2021 Preliminary Analysis TSD, DOE requested comment on a variety of other potential equipment setting factors. (August 2021 Preliminary Analysis TSD at p. 2–16–22) These comments are discussed in detail below.

a. Pole- and Pad-Mounted Transformers

DOE currently does not divide pole- and pad-mounted distribution transformers into separate equipment classes. In the August 2021 Preliminary Analysis TSD, DOE requested comment and data to characterize the effect of mounting configuration on distribution transformer efficiency, weight, volume, and likelihood of introducing ferroresonace.[44] (August 2021 Preliminary Analysis TSD at p. 2–19)

Eaton commented that ferroresonance is rare and only occurs in pad mounted transformers. (Eaton, No. 55 at pp. 9–10) Eaton added that ferroresonance is more likely to occur in low no-load loss cores, and commented that these effects can be mitigated with certain core designs that are slightly less efficient. (Eaton, No. 55

[43] 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 identifies the transformer as being for this use only. 10 CFR 431.192.

[44] Ferroresonance refers to the nonlinear resonance resulting from the interaction of system capacitive and inductive elements which can lead to damaging high voltages in distribution transformers. Pad-mounted distribution transformers that are delta-connected are particularly susceptible to ferroresonance effects.

at pp. 9–10) Eaton added that it has produced thousands of low-loss 5-leg distribution transformers and is unaware of a single occurrence of ferroresonace. (Eaton, No. 55 at pp. 9–10)

DOE did not receive any data suggesting that pole- and pad-mounted distribution transformers warrant separate equipment classes. As such, DOE has not proposed to amend the current equipment class structure for pole- and pad-mounted distribution transformers. Further, DOE includes both pole- and pad-mounted representative units in its engineering analysis.

b. Submersible Transformers

Certain distribution transformers are installed underground and, accordingly, may endure partial or total immersion in water. This scenario commonly arises for distribution transformers installed in chambers called ''vaults'', which are commonly made of concrete. Access is typically, but not always, through an opening in the top (''ceiling'') face of the vault, through which the distribution transformer can be lowered for installation or replacement.

''Submersible'', ''network'' and ''vault-based'' are three attributes that often all apply to a particular distribution transformer unit, but which carry distinct meanings. Informally, ''submersible'' refers to ability to operate while submerged, ''network'' refers to ability to operate as part of a network of interconnected secondary windings as most typically occurs in urban environments, and ''vault-based'' refers to siting within a vault, which may be but is not necessarily below grade. A given distribution transformer, for example, may be installed within an above-grade vault but not rated as submersible. Similarly, a particular network distribution transformer may happen to be installed within a vault, but able to operate as well outside of a vault.

In the April 2013 Standards Final Rule, DOE included additional costs for vault replacements in the LCC analysis but noted there was no technical barrier that prevents network, vault-based and submersible distribution transformers from achieving the same efficiency levels as other liquid-immersed distribution transformers. 78 FR 23336, 23356–23357. In the August 2021 Preliminary Analysis TSD, DOE preliminarily stated that it would take a similar approach in applying the costs of vault enlargement as a function of increased distribution transformer volume for RU4 and RU5. (August 2021 Preliminary Analysis TSD at p. 2–89)

DOE requested comment on some of the options a customer is likely to explore before incurring the cost of vault expansion, such as using a lower-loss core steel, copper windings, or a less-flammable insulating fluid. (August 2021 Preliminary Analysis TSD at p. 2–20)

NEMA commented that when trying to fit into a given space, copper windings may allow for a 20 percent size reduction relative to aluminum and higher-grade core steels can help, but it is still sometimes very difficult to reduce footprint while meeting standards. (NEMA, No. 50 at p. 6) Carte requested an exclusion for retro fit designs. (Carte, No. 54 at p. 2)

Carte commented that most network transformers are lightly loaded but redundancy is quite important and as such many customers require high overload capabilities. (Carte, No. 54 at p. 1) Carte added that in certain applications, with limited space, there is reduced cooling which forces manufacturers to lower load loss at the expense of core loss to maintain reliable operation. (Carte, No. 54 at pp. 1–2) EEI recommended DOE include a separate product class for vault transformers. (EEI, No. 56 at p. 3)

As discussed, EPCA requires that a rule prescribing an energy conservation standard for a type of covered equipment specify a level of energy use or efficiency higher or lower than that which applies (or would apply) to any group of covered equipment that has the same function or intended use, if the Secretary determines that covered equipment within such group:

(A) Consume a different kind of energy from that consumed by other covered products within such type (or class); or

(B) Have a capacity or other performance-related feature that other products within such type (or class) do not have and such feature justifies a higher or lower standard from that which applies (or will apply) to other products within such type (or class). (42 U.S.C. 6313(a); 42 U.S.C. 6295(q)(1))

In making a determination of whether a performance-related feature justifies the establishment of a higher or lower standard, the Secretary must consider such factors as the utility to the consumer of such a feature, and such other factors as the Secretary deems appropriate. *Id.*

As noted, DOE previously determined there was no technical barrier to vault distribution transformers achieving similar efficiency standards as other similar distribution transformers. To the extent significant costs arise for more-efficient units, they are generally installation costs (*i.e.,* expanding the size of the vault in which the distribution transformer is installed). Installation costs are addressed in the LCC and PBP analyses, as well as in consumer subgroup-specific analyses. These analyses account for the cost of difficult (*i.e.,* unusually costly) installations, including those subgroups of the population that may be differentially impacted by DOE's consideration of amended energy conservation standards (*see* section IV.I.2 of this document).

Review of comments and the equipment market indicates that certain vault-based distribution transformers also are designed to operate in submersible applications. Because many vaults are subterranean, distribution transformers installed in such locations often require ability to operate while submerged. Installation below grade makes more likely that distribution transformers may operate while submerged in water and with other run-off debris. Distribution transformers for installation in such environments are designed to withstand harsh conditions, including corrosion.

The subterranean installation of submersible distribution transformers means that there is less circulation of ambient air for shedding heat. 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.

With respect to heat transfer, the industry standards governing submersible distribution transformers, *i.e.,* IEEE C57.12.23–2018 and C57.12.24–2016, specify that submersible distribution transformers, amongst other requirements, have their capacity rated for a maximum temperature rise of 55°C but have their insulation be rated for 65°C. IEEE C57.12.80–2010 defines submersible distribution transformer as ''a transformer so constructed as to be successfully operable when submerged in water under predetermined conditions of pressure and time.''

Distribution transformer temperature rise tends to be governed by load losses. Often, design options that reduce load losses, increase no-load losses. While no-load losses make up a relatively small portion of losses at full load, no-load losses contribute approximately equally to load losses at 50 percent PUL, at which manufacturers must certify efficiency. The potentially reduced heat transfer of the subterranean environment, combined with the possibility of operating while submerged, limits customers from meeting the temperature rise limitations through any choice other than reducing load losses. Therefore, the design choices needed to meet a lower temperature rise, may tend to lead manufacturers to increase no-load losses and may make it more difficult to meet a given efficiency standard at 50 percent PUL.

DOE recognizes that distribution transformers other than those designed for submersible operation may be derated (rated for a lower temperature rise) for other reasons, such as installation in ambient temperatures over 40°C, greater harmonic currents, or installation at altitudes above 1000 meters. However, the ability to improve the efficiency of such distribution transformers is not similarly limited as submersible distribution transformers because other options exist for distribution transformers above grade that would not be feasible in submerged environments, namely the ability to increase heat transfer, often with some additional cost, as opposed to only options that increase a distribution transformer's no-load losses. For example, distribution transformers installed above grade may be able to have more air circulation through radiators, improving the efficiency of radiators to shed heat, or adding external forced air cooling on a distribution transformer radiator, whereas such a measure would not be able to function as intended in a submerged environment.

Based on the foregoing discussion, DOE has tentatively determined that distribution transformers designed to operate while submerged and in contact with run-off debris have a performance-related feature which other types of distribution transformers do not have. While at max-tech efficiency levels both no-load and load losses are so low that distribution transformers generally do not meet their rated temperature rise, at intermediate efficiency levels, trading load losses for no-load losses allows distribution transformers to be rated for a lower temperature rise, however, it also 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 rated temperature rise. Therefore, DOE is proposing that providing for operation in installation locations at which the units are partially or wholly submerged in water justifies a different standard on account of the additional constraint which forces manufacturers to trade load losses for no-load losses. DOE has modeled the derating of these distribution transformers and the associated costs associated with these submersible distribution transformers, as described in section IV.C.1 of this document.

In proposing separate equipment classes, DOE relies on physical features to distinguish one product class from another. While the IEEE definition of ''submersible transformer'' described how a submersible distribution transformer should perform, it does not include specific physical features that would allow DOE to identify submersible transformers from other general purpose distribution transformers. In reviewing industry standards, DOE notes that submersible distribution transformers are rated for a temperature rise of 55°C, have insulation rated for 65°C, have sealed-tank construction, and have the tank, cover, and all external appurtenances be made of corrosion-resistant material. Consistent with industry practice, DOE is proposing to define 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.''

DOE notes that IEEE C57.12.80–2010 defines several other types of distribution transformers that would potentially also meet the proposed definition of ''submersible distribution transformer.'' IEEE C57.12.80–2010 defines ''vault-type transformer'' as ''a transformer that is so constructed as to be suitable for occasional submerged operation in water under specified conditions of time and external pressure.'' Similarly, IEEE C57.12.80–2010 defines ''network transformer'' as ''a transformer designed for use in a vault to feed a variable capacity system of interconnected secondaries,'' and states that ''a network transformer may be of the submersible or of the vault type.'' To the extent network and vault-type distribution transformers were to meet the proposed definition of submersible distribution transformer, they would be included in the submersible distribution transformer equipment class.

DOE requests comment on its understanding and proposed definition of ''submersible'' distribution transformer. Specifically, DOE requests information on specific design characteristics of distribution transformers that allow them to operate while submerged in water, as well as data on the impact to efficiency resulting from such characteristics.

DOE requests comment and data as to the impact that submersible characteristics have on distribution transformer efficiency.

c. 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 [45] 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 p. 2–21) DOE requested comment on the difference in losses associated with multi-voltage distribution transformers. (August 2021 Preliminary Analysis TSD at p. 2–21)

Schneider commented that the higher nominal voltage tends to be more efficient, but the degree of increased losses depends on the kVA and difference between nominal voltages. (Schneider, No. 49 at p. 9) Schneider commented that the challenge for DOE is ensuring manufacturers are testing in worst case conditions and recommended DOE require manufacturers to identify these transformers and/or requiring on the distribution transformer nameplate. (Schneider, No. 49 at pp. 10–12) Schneider recommended DOE audit these multi-voltage designs to ensure they are testing under proper conditions. (Schneider No. 49 at pp. 12–13) Schneider expanded that these products should not have a separate equipment class but should be audited by DOE. (Schneider, No. 49 at p. 13)

Schneider's data indicates that the degree of coil loss increase associated with multi-voltage secondary distribution transformers ranges from 3.7 percent to 10.8 percent of full-load coil losses. (Schneider No. 49 at p. 10)

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

DOE notes that each efficiency level considered offers a range of no-load and load loss combinations for meeting efficiency levels. While a multi-voltage transformer may require manufacturers to invest more in reducing no-load loss relative to a similar single voltage transformer, it would generally still be able to serve those customers' needs that request a multi-voltage distribution transformer.

ERMCO and NEMA acknowledged that some multi-voltage units may have a harder time achieving efficiency standards but did not provide a recommendation as to how to treat them. (ERMCO, No. 45 at p. 1; NEMA, No. 50 at p. 6) Eaton commented that transformers with multiple voltage rating and non-whole integer ratings have unused turns and require additional space in the core window leading to higher losses. (Eaton, No. 55 at p. 12) Carte identified emergency use distribution transformers which have multiple high voltages and low voltages and can be used anywhere in a system until a proper replacement is added, and asked how standards apply to them. (Carte, No. 54 at p. 2)

As discussed, EPCA requires that a rule prescribing an energy conservation standard for a type of covered equipment specify a level of energy use or efficiency higher or lower than that which applies (or would apply) to any group of covered equipment that has the same function or intended use, if the Secretary determines that covered equipment within such group:

(A) Consume a different kind of energy from that consumed by other covered products within such type (or class); or

(B) Have a capacity or other performance-related feature that other products within such type (or class) do not have and such feature justifies a higher or lower standard from that which applies (or will apply) to other products within such type (or class).

(42 U.S.C. 6313(a); 42 U.S.C. 6295(q)(1))

In making a determination of whether a performance-related feature justifies the establishment of a higher or lower standard, the Secretary must consider such factors as the utility to the consumer of such a feature, and such other factors as the Secretary deems appropriate. *Id.*

DOE acknowledges that multi-voltage distribution transformers, specifically those with non-integer ratios, 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 replacing a distribution transformer. These transformers are often used in upgrading distribution line voltages and as such when the distribution line voltage is upgraded, these distribution transformers would have greater efficiency than their certified efficiency. These distribution transformers have additional, unused winding turns when operated at their lower voltage which increase losses. However, once the distribution grid has been increased to the higher voltage, the entire winding will be used, increasing the efficiency of the product. However, DOE lacks data as to the degree of no-load loss and load loss increase associated with transitioning from a single primary and secondary voltage distribution transformer to a multi-voltage distribution transformer.

DOE notes that the NRCAN regulations specify that ''For a three-phase transformer having multiple high-voltage windings and a voltage ratio other than 2:1, the minimum energy efficiency standard from the table or interpolated is reduced by 0.11.'' Similarly, EU regulations permit between a 10 to 20 percent increase in load losses for dual voltage transformers and between 15 and 20 percent increase in no-load losses, depending on the type of dual voltage.

Schneider commented that multi-voltage transformers do not need a lesser standard as it is a manufacturers choice to produce them. (Schneider, No. 49 at p. 10) Schneider added that they have many non-integer multi-voltage ratios offered and do not believe it is necessary to create a new class for these products. (Schneider, No. 49 at p. 10)

Stakeholder comments suggest that the difference in voltages associated with multi-voltage distribution transformers is relatively small. Further, technologies that increase the efficiency of single-voltage distribution transformers also increase the efficiency of multi-voltage distribution transformers. For these reasons, DOE has not proposed a separate equipment class for multi-voltage-capable distribution transformers with a voltage ratio other than 2:1.

However, DOE may consider a separate product class if sufficient data is provided to demonstrate that these distribution transformers justify a different energy conservation standard. DOE notes that these distribution transformers would not be permitted to have a lesser standard than currently applicable to them on account of EPCA's anti-backsliding provisions at 42 U.S.C. 6295(o).

DOE requests data on the difference in load loss by kVA for distribution transformers with multiple-voltage ratings and a voltage ratio other than 2:1.

DOE request data on the number of shipments for each equipment class of distribution transformers with multi-voltage ratios other than 2:1.

d. High-Current Distribution Transformers

Carte commented that low secondary voltages with high currents can increase the cost and weight of a distribution transformer and may require switching to copper. (Carte, No. 54 at p. 1) NEMA commented that new production machines may be needed for certain winding configurations near technical limits, such as large kVA distribution transformers with 208 voltage secondaries. (NEMA, No. 50 at p. 10) Eaton commented that lower voltage windings have higher currents which may require rectangular conductors and can make winding more complicated. (Eaton, No. 55 at p. 12) Eaton added that at some sizes, the conductor becomes too thick to be used in a transformer. (Eaton, No. 55 at p. 12) NEMA commented that these designs are on the cusp of max-tech today. (NEMA, No. 50 at p. 10)

Distribution transformers with high currents tend to have increased stray losses which can impact the efficiency of distribution transformers. NEMA cited a 2,000 kVA design with a 208V secondary where buss losses contribute approximately 12 percent to the full load losses of the transformer. (NEMA, No. 50 at p. 5) DOE notes that NRCAN regulations exclude transformers with a nominal low-voltage line current of 4000 A or more. In general, this amperage limitation would impact large distribution transformers with low-voltage secondary windings.

DOE notes that in high-current applications, while stray losses may be slightly higher, manufacturers have the option to use copper secondaries to decrease load losses or a copper buss bar. Technologies that increase the efficiency of lower-current distribution transformers also increase the efficiency of high-current distribution transformers. To the extent new production machines would be needed to accommodate the increased strip widths associated with high-current distribution transformers, those would be accounted for in the manufacturer impact analysis. For these reasons, DOE has not proposed a separate equipment class for high-current distribution transformers.

However, DOE may consider a separate product class if sufficient data is provided to demonstrate that high-current distribution transformers justify a different energy conservation standard. DOE notes that these distribution transformers would not be permitted to have a lesser standard than currently applicable to them on account of EPCA's anti-backsliding provisions at 42 U.S.C. 6295(o).

DOE requests data on the difference in load loss by kVA for distribution transformers with higher currents and at what current it becomes more difficult to meet energy conservation standards.

DOE requests data as to the number of shipments of distribution transformers with the higher currents that would have a more difficult time meeting energy conservation standards.

e. Data Center Distribution Transformer

In the April 2013 Standard Final Rule, DOE considered a separate equipment class for data center distribution transformers, 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 in-rush current) less than or equal to four times its rated full load current multiplied by the square root of 2, as measured under the following conditions—

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

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

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

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

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

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

2. Temperature rise less than 130 °C with class 220 (25) insulation or temperature rise less than 110 °C with class 200 (26) insulation;

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

4. Copper primary and secondary windings;

5. An electrostatic shield; or

6. Multiple outputs at the same voltage a minimum of 15° apart, which when summed together equal the transformer's input kVA capacity.'' [46]

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 in-rush 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 p. 2–22)

DOE did not receive any comments as to physical features that could distinguish a data center distribution transformer from a general-purpose distribution transformer.

DOE requests comment as to what modifications could be made to the April 2013 Standard Final Rule data center definition such that the identifying features are related to efficiency and would prevent a data center transformer from being used in a general purpose application.

NEMA commented that most data center transformers are outside the scope due to kVA range, but those still within scope would likely have high loading and would not be favored for amorphous transformers. (NEMA, No. 50 at p. 6)

[46] 78 FR 23336, 23358.

Eaton commented that liquid-immersed distribution transformers are increasingly being used in data center applications. (Eaton, No. 55 at p. 10) Eaton added that the quantity and overall energy consumed in data center applications has increased significantly. (Eaton, No. 55 at p. 10) Eaton commented that the lifespan of a data center transformer would vary depending on loading. (Eaton, No. 55 at p. 11)

Eaton commented that liquid-immersed data center transformers are designed to operate between 50–75 percent PUL and are typically specified to meet DOE efficiency standards. (Eaton, No. 55 at pp. 10–11)

DOE did not receive any comments suggesting that data center distribution transformers warrant a separate product class. As such, DOE has not proposed a definition for data center distribution transformers and has not evaluated them as a separate product class. However, DOE may consider a separate product class if sufficient data is provided to demonstrate that data center transformers warrant a different efficiency level and can appropriately be defined. 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.

DOE requests comment regarding its proposal not to establish a separate equipment class for data center distribution transformers. In particular, DOE seeks comment regarding whether data center distribution transformers are able to reach the same efficiency levels as distribution transformers generally and the specific reasons why that may be the case.

DOE requests comment regarding any challenges that would exist if designing a distribution transformer which uses amorphous electrical steel in its core for data center applications and whether data center transformers have been built which use amorphous electrical steel in their cores.

DOE requests comment on the interaction of inrush current and data center distribution transformer design. Specifically, DOE seeks information regarding: (1) the range of inrush current limit values in use in data center distribution transformers; (2) any challenges in meeting such inrush current limit values when using amorphous electrical steel in the core; (3) whether using amorphous electrical steel inherently increases inrush current, and why; (4) how the (magnetic) remanence of grain-oriented electrical steel compares to that of amorphous steel; and (5) other strategies or technologies than distribution transformer design which could be used to limit inrush current and the respective costs of those measures.

f. BIL Rating

Distribution transformers are built to carry different basic impulse level (''BIL'') ratings. BIL ratings offer increased resistance to large voltage transients, for example, from lightning strikes. Due to the additional winding clearances required to achieve a higher BIL rating, high BIL distribution transformers tend to be less efficient, leading to higher costs and be less able to achieve higher efficiencies. DOE separates medium-voltage dry-type distribution transformers into equipment classes based on BIL ratings. 10 CFR 431.196(c).

In the August 2021 Preliminary Analysis TSD, DOE noted stakeholder comments that evaluating additional liquid-immersed distribution transformers based on BIL rating would add additional complications for minor differences in losses. As such, DOE did not consider BIL in its evaluation of liquid-immersed distribution transformers.

In response, Howard commented that 150 kV and 200 kV BIL units should not have their efficiency standards increased as these units are already too large. (Howard, No. 59 at pp. 1–2) Carte commented that 200 kV BIL transformers have more insulation that increases the size of the transformer and therefore the losses of the transformer. (Carte, No. 54 at p. 1) Eaton commented that high BIL transformers can have a harder time meeting efficiency standards. (Eaton, No. 55 at p. 12) Neither Eaton, Howard nor Carte provided any data suggesting the degree of efficiency difference as BIL is increased. Based on the discussion in the preceding paragraphs, DOE is not proposing a separate equipment class based on BIL rating for liquid-immersed units but may consider it if sufficient data is provided.

DOE requests data as to how a liquid-immersed distribution transformer losses vary with BIL across the range of kVA values within scope.

Regarding MVDTs, NEMA commented that MVDT with BIL levels above 150 kV are essentially non-existent and would not represent a significant amount of energy savings if regulated. (NEMA, No. 50 at p. 7)

DOE notes that MVDTs above 150 kV BIL are currently regulated. In the August 2021 Preliminary Analysis TSD, DOE requested data on the change in efficiency associated with higher BIL ratings for distribution transformers and the volume of dry-type distribution transformers sold with BIL ratings above 199 kV. DOE did not receive any data and therefore has maintained its current equipment class separation of MVDTs.

g. Other Types of Equipment

Stakeholders identified several other distribution transformer types that they noted may have a harder time meeting efficiency standards. NEMA commented that MVDTs at high altitude may require more air clearance and therefore must accommodate higher core loss, and as such, may warrant a separate equipment class. (NEMA, No. 50 at p. 5) Carte asked DOE to analyze main and teaser and Scott connected transformers which it stated are unique to certain industrial grids and can be very difficult or impossible to replace.[47] (Carte, No. 54 at p. 2)

Carte asked how efficiency standards apply to duplex transformers which have two kVA ratings on one transformer.[48] (Carte, No. 54 at p. 2) Carte asked if three winding simultaneous loading transformers used in solar applications to isolate the low-voltage qualify for an exemption. (Carte, No. 54 at p. 2)

DOE did not receive any data as to the degree of difference in efficiency associated with these distribution transformers. DOE has not considered any of the noted products as separate equipment classes in this NOPR analysis due to lack of data as to the shipments and reduction in efficiency associated with certain designs. Regarding how standards are applied to certain equipment, DOE notes that equipment that meets the definition of distribution transformer is subject to energy conservation standards at 10 CFR 431.196.

DOE requests comments and data on any other types of equipment that may have a harder time meeting energy conservation standards. Specifically, DOE requests comments as to how these other equipment are identified based on physical features from general purpose distribution transformers, the number of shipments of each unit, and the possibility of these equipment being used in place of generally purpose distribution transformers.

[47] Main and Teaser and Scott connected transformers are a special type of transformer which converts from three-phase energy to two phase energy or vice versa using two electrically-connected single-phase transformers

[48] Duplex transformers consist of two single-phase transformers assembled in a single enclosure. They are generally used to provide a large single-phase output in tandem with a smaller three-phase output

3. Test Procedure

The current test procedure for measuring the energy consumption of distribution transformers is established at appendix A to subpart K of 10 CFR part 431. In a September 2021 TP Final Rule, DOE maintained that energy efficiency be evaluated at 50 percent PUL for liquid-immersed distribution transformers and medium-voltage dry-type distribution transformers and 35 percent PUL for low-voltage dry-type distribution transformers. 86 FR 51230. In the August 2021 Preliminary Analysis TSD, DOE acknowledged that its estimates for current root-mean-square (''RMS'') in-service loading is less than the test procedure PUL but noted there was uncertainty which makes it preferential to overestimate PUL rather than underestimate PUL. DOE noted that any potential energy savings that could be achieved by changing the standard PUL could also be achieved by increasing the stringency of the energy conservation standards. As such, DOE only considered distribution transformers that would meet energy conservation standards at DOE's test procedure loading, but evaluated energy saving potential using in-service data and load growth estimates.

In response, CDA agreed with the test procedure loading and stated that they believe the loading will match future forecasts. (CDA, No. 47 at p. 2)

NEEA and the Efficiency Advocates commented that the test procedure PUL is too high and leads to designs that over-invest in load losses, and as such, DOE should reduce the test procedure PUL. (Efficiency Advocates, No. 52 at pp. 1–2; NEEA, No. 51 at pp. 7–8) The Efficiency Advocates commented that DOE's preliminary analysis shows that intermediate energy savings can be achieved with small price increases if transformer designs are optimized for more realistic PULs and urged DOE to consider revising its test procedure PUL, given the preliminary analysis load growth estimates. (Efficiency Advocates, No. 52 at p. 2) The Efficiency Advocates commented that the negative savings at certain ELs reflect the fact that certain ELs would be met by decreasing load losses rather than no-load losses. (Efficiency Advocates, No. 52 at pp. 2–3) The Efficiency Advocates further referenced DOE's hourly load model which they claim demonstrated a small percentage of hours above 50 percent PUL and indicates savings available at lower PULs. (Efficiency Advocates, No. 52 at p. 4) The Efficiency Advocates commented that a lower PUL permits greater savings for less costs, claiming that DOE's data shows better optimizing a transformer could yield 23 percent energy savings for only a 4 percent increase in costs. (Efficiency Advocates, No. 52 at pp. 4–5)

DOE notes that the potential energy savings cited by the Efficiency Advocates are based on a distribution transformer that is optimized at 35 percent PUL and is meeting current efficiency standards at 50 percent PUL. In the scenario where an alternative test procedure PUL is used, distribution transformers would not have to meet the current standard at 50 percent PUL, they would only have to meet a new standard at 35 percent PUL. DOE's analysis of energy conservation standards assumes consumers select a range of distribution transformers and applies a range of unique customer loading profiles to evaluate the impacts of amended energy conservation standards. In a theoretical evaluation of energy conservation standards at 35 percent PUL, the whole analysis would change as new distribution transformers would be able to be purchased by consumers that do not meet current standards at 50 percent PUL but may meet a standard at 35 percent PUL. Without doing a much more detailed analysis, it is a vast oversimplification to cite energy savings from a single distribution transformer. Further, DOE notes that many of the distribution transformers optimized for low PULs use amorphous cores and represent the design options with the highest efficiency at 50 percent PUL.

Powersmiths commented that measuring LVDT efficiency at a single load point is insufficient since the efficiency varies dramatically over the loading. (Powersmiths, No. 46 at p. 1) Powersmiths added that 35 percent PUL is not representative for LVDTs. (Powersmiths, No. 46 at p. 1) Powersmiths added that evaluating at 35 percent PUL enables manufacturers to publish peak efficiency rather than how their transformers perform in the real world. (Powersmiths, No. 46 at p. 2) Powersmiths commented that this practice misleads customers into thinking DOE compliant transformers save them the most money, when transformers optimized for lower loading could save more energy and money. (Powersmiths, No. 46 at p. 2)

Metglas commented that actual data shows current loading is low and as such, the liquid-immersed distribution transformers should be evaluated at 35 percent load and LVDTs should be evaluated at 20 percent load. (Metglas, No. 53 at p. 1; Metglas, No. 53 at p. 6)

Powersmiths added that the 35 percent PUL for LVDTs produces deceptively high savings estimates and pushing up efficiency at that point is counterproductive. (Powersmiths, No. 46 at p. 2) Powersmiths recommended DOE work with organizations to reduce oversizing of distribution transformers. (Powersmiths, No. 46 at p. 2)

DOE agrees with stakeholders that current loading is lesser than the test procedure PUL. As such, DOE relies on the most accurate in-service PUL and load growth estimates to calculate energy savings potential. However, DOE evaluates the efficiency of distribution transformers and only includes distribution transformer models that would meet amended energy conservation standards at the test procedure PUL. The efficiency of distribution transformers over the duration of its lifetime and across all installations cannot be fully represented by a single PUL. A given transformer may be highly loaded or lightly loaded depending on its application or variation in electrical demand throughout the day. In the September 2021 TP Final Rule, DOE was unable to conclude that any singular PUL would be more representative than the current test procedure PUL because of (1) significant long-term uncertainty regarding what standard PUL would correspond to a representative average use cycle for a distribution transformer given their long lifetimes; and (2) given the uncertainty of future loading, there may be greater risk associated with selecting a test procedure PUL that is too low than a test procedure PUL that is too high. 86 FR 51230, 51240. Therefore, for purposes of evaluating the proposed standards in this document, DOE used the test procedure PUL. More discussion of the test procedure PUL may be found in the September 2021 TP Final Rule.

DOE disagrees with commenters' assertion that there is an inherent benefit associated with distribution transformers certified at an alternative PUL as no energy conservation standard exist at any alternative PUL. Further, DOE believes any benefits associated with a lower PUL are also achieved via amended energy conservation standards. DOE has presented plots in chapter 3 of the TSD to demonstrate how the design space of possible load loss and no-load loss combinations would change in the presence of amended energy conservation standards and if energy conservation standards were evaluated at an alternative PUL which helps demonstrate this conclusion.

Powersmiths commented that the current reporting system is flawed as factors like sub-standard batches of steel may result in noncompliant distribution transformers being shipped, and recommended DOE should require third party testing of distribution transformers. (Powersmiths, No. 46 at pp. 6–7) DOE notes that it has no data suggesting manufacturers are shipping non-compliant distribution transformers. DOE notes that in the case of sub-standard steel batches, its certification requirements permit some degree of variability in equipment performance, as described at 10 CFR 429.47.

Powersmiths commented that high volume manufacturers optimize costs by using higher loss core steel and lower loss conductor material to meet the 35 percent legal limit. (Powersmiths, No. 46 at p. 2) Powersmiths recommended lowering the LVDT test procedure PUL or adding a core loss limit to secure real world energy savings. (Powersmiths, No. 46 at p. 2)

In the September 2021 TP Final Rule, DOE noted that on account of uncertainty associated with future distribution transformer loading, DOE is unable to conclude that any alternative single-PUL efficiency metric is more representative than the current standard PUL. 86 FR 51230, 51240. Therefore, DOE only evaluated distribution transformers that would meet amended efficiency standards at the current test procedure PUL. In its evaluation of energy savings, DOE used data representative of current in-service loading, as described in section IV.E. DOE does not make assumptions as to the maximum no-load or load losses of a transformer and instead relies on the consumer choice model, described in section IV.F.3 of this document, to evaluate the distribution transformers that consumers are likely to purchase.

4. Technology Options

In the preliminary market analysis and technology assessment, DOE identified several technology options that would be expected 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 0 percent PUL but grow quadratically with PUL.

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

CDA commented that copper is the best conductor of electricity and enables a more compact and economical distribution transformer with a smaller tank, less core, and reduced oil. (CDA, No. 47 at p. 1) DOE notes that it has included some copper windings in its engineering analysis and recognizes that while copper may be more expensive than aluminum conductors, it represents a technology option that allows manufacturers to achieve smaller footprints or higher efficiencies in designs that are uniquely difficult to meet energy conservation standards.

EEI commented that many technologies that decrease no-load losses, increase load losses and therefore DOE should utilize accurate projections of loading and recognize lower-loss core materials can have significantly higher load losses. (EEI, No. 56 at p. 3)

Regarding amended energy conservation standards generally, Howard commented that no new technology options have come onto the market that would impact distribution transformer efficiency since the April 2013 Standards Final Rule. (Howard, No. 59 at p. 1) CDA commented that there should be no new standards and recommended DOE continue to evaluate the inputs to its analysis and new technologies. (CDA, No. 47 at p. 2) Powermiths noted that the market is in flux currently and recommended DOE delay the rulemaking while the market settles, require third party compliance enforcement, and invite stakeholder into DOE's revision process. (Powersmiths, No. 46 at p. 7)

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 configurations. With respect to commenters' suggestions that DOE delay standards or not issue amended standards, as noted previously, EPCA requires DOE to periodically determine whether more-stringent standards would be technologically feasible and economically justified, and would result in significant energy savings. 42 U.S.C. 6316(a); 42 U.S.C. 6295(m). DOE has tentatively concluded that the proposed standards 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 achieving these standard levels are already commercially available for all product classes covered by this proposal. Accordingly, DOE has proceeded with the proposed standards.

5. Electrical Steel 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 amorphous steel and grain-oriented electrical steel (''GOES''). There are many subcategories of steel within both amorphous steel and grain-oriented electrical steel. In the August 2021 Preliminary Analysis TSD, DOE assigned designated names to identify the various permutations of electrical steel. (August 2021 Preliminary Analysis TSD at pp. 2–31–36) DOE requested comment on its proposed naming convention. In response, Schneider and NEMA commented that the proposed naming convention used by DOE in the preliminary analysis is adequate. (Schneider, No. 49 at p. 13; NEMA No. 50 at p. 8)

The various markets, technologies, and naming conventions for amorphous and GOES are discussed in the following sections.

a. Amorphous Steel Market and Technology

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

DOE has identified three sub-categories of amorphous steel as possible technology options. These technology options and their DOE naming shorthand are shown in Table IV.2.

TABLE IV.2—AMORPHOUS STEEL TECHNOLOGY OPTIONS

DOE designator in design options	Technology
am	Traditional Amorphous Steel.
hibam	High-Permeability Amorphous Steel.
hibam-dr	High-Permeability, Domain-Refined, Amorphous Steel.

In the August 2021 Preliminary Analysis TSD, DOE requested comment and data on the quality and differences between the various amorphous steels on the market. (August 2021 Preliminary Analysis TSD at p. 2–31)

In response, Metglas commented that since amorphous steel was introduced, the core loss and stacking factor of the product has continually improved. (Metglas, No. 53 at pp. 2–3) Metglas stated that the current stacking factors are between 88–90 percent, which allows amorphous cores to be smaller than they have historically been. (Metglas, No. 53 at pp. 2–3) Eaton commented that the hibam material uses an 89 percent stacking factor and max flux of 1.40–1.42 tesla (T), as compared to traditional amorphous material which uses 88 percent stacking factor and a flux of 1.35–1.37 T. (Eaton, No. 55 at p.11) NEMA commented that the stacking factor of amorphous steel will never be as high as grain-oriented electrical steel. (NEMA, No. 50 at p. 8)

In the August 2021 Preliminary Analysis TSD, DOE noted that it did not include any designs specifically using the high-permeability amorphous steel. (August 2021 Preliminary Analysis TSD, at p. 2–45) DOE stated while there are some design flexibility advantages associated with using the high-permeability amorphous steel, it is only available from a single supplier. *Id.* In interviews, manufacturers noted they would be hesitant to rely on a single supplier of amorphous material for any higher volume unit. *Id.* DOE further stated that high-permeability amorphous steel can be integrated in manufacturer existing amorphous designs with minimal changes and therefore, DOE's amorphous designs represent efficiencies that can be met with any amorphous steel. *Id.* DOE requested comment on its assumption that high-permeability amorphous steel could be used in existing amorphous designs with minimal changes. *Id.*

In response, Metglas commented that hibam can be used interchangeably with the standard am designs. (Metglas, No. 53 at p. 4) Metglas added that many transformers will maintain existing am design and operate the hibam material at the lower induction levels during initial conversion, however, once designs are optimized for the hibam material, they cannot substitute standard am because standard am cannot reach the higher induction levels. (Metglas, No. 53 at p. 4) Metglas added that there is not a reduction in core losses when operating hibam at the same induction levels as standard am. (Metglas, No. 53 at p. 4)

NEMA and Eaton commented that hibam does not necessarily have higher efficiency than standard am at certain flux densities, and it is not universally true that hibam could be used in place of standard am without other design changes because at some flux densities, standard am can have lower no-load losses. (Eaton, No. 55 at p. 12–13; NEMA, No. 50 at p. 10)

Stakeholder comments confirm DOE's assumption that hibam material can be used in place of standard am designs, generally, although some specific applications may require redesigning. As such, including only standard am designs in the NOPR analysis is appropriate to avoid setting efficiency standards based on a steel type, 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.

In the August 2021 Preliminary Analysis TSD, DOE noted that it was aware of a hibam material that uses domain refinement (''hibam-dr'') to further reduce core losses but did not have sufficient data or details as to whether it is commercially available. (August 2021 Preliminary Analysis TSD, at p. 2–31) In response, Metglas commented that they have introduced a mechanically domain refined hibam material that lowers core losses by an additional 20–30 percent in a finished core at a constant operating induction and there is a laser domain refined hibam product in the Asian market that Metglas is working to bring online in the domestic market. (Metglas, No. 53 at p. 3) Metglas commented that hibam-dr allows manufacturers to increase operating induction, relative to standard am, while reducing core losses by approximately 14 percent relative to the standard am operating induction. (Metglas, No. 53 at p. 4)

DOE further investigated this product in manufacturer interviews conducted for this NOPR analysis. In these interviews, DOE learned that the hibam-dr product is not yet widely available commercially. DOE has not included the hibam-dr product in its analysis because this product has not been widely used in commercial applications at this point, DOE has not been able to verify that the core loss reduction of this product is maintained throughout the core production process, and it is only produced by one supplier.

In the April 2013 Standard Final Rule, one concern DOE noted with efficiency levels that would use amorphous steel was that there was only one global supplier of amorphous steel. 78 FR 23336, 23383. In the June 2019 Early Assessment RFI, DOE estimated global amorphous capacity of 190,000 metric tons and noted that the capacity and number of producers of amorphous steel has grown since the April 2013 Standards Final Rule. 84 FR 28239, 28247

Metglas commented that it is the only current producer of amorphous steel in the United States, however, there is current production in Japan and China along with amorphous capacity in Germany and South Korea. (Metglas, No. 11 at p. 2) Eaton pointed out that one barrier to steel manufacturers producing amorphous is that it would ''cannibalize'' conventional electrical steel manufacturers existing product offering and reduce the equipment utilization of existing equipment. (Eaton, No. 12 at p. 6)

In the August 2021 Preliminary Analysis TSD, DOE noted that it had identified numerous companies capable of producing amorphous material (of standard am quality or better). DOE stated that it did not apply any capacity constraints on the number of amorphous distribution transformers that could be selected because amorphous capacity is much greater than amorphous demand.

The Efficiency Advocates commented that the preliminary analysis shows a transition to amorphous material is cost justified and would bring U.S. standards in-line with other parts of the world. (Efficiency Advocates, No. 52 at p. 1) The Efficiency Advocates added that if amorphous core availability is a concern, DOE could require amorphous cores for certain transformer types that offer large savings. (Efficiency Advocates, No. 52 at p. 8)

Metglas estimated global amorphous capacity to be 150,000 metric tons annually with domestic capacity of 45,000 metric tons and ready ability to add another 75,000 metric tons within 18–24 months. (Metglas, No. 53 at p. 3) Metglas commented that the high-permeability amorphous grades (hibam) has been widely adopted by the North American market, making up 80 percent of their production, and allows for higher operating inductions which reduces amorphous core sizes. (Metglas, No. 53 at p. 3) NEMA commented that amorphous steel sourced from China is more variable in its stacking factor and consistency. (NEMA, No. 50 at p. 8)

Stakeholder comments verify that global amorphous capacity is much greater than current demand and amorphous is produced by a variety of sources, although the quality may not be as consistent from everybody. Through manufacturer interviews, DOE learned that amorphous production capacity increased in response to the April 2013 Standards Final Rule, resulting in excess capacity because demand for amorphous steel did not correspondingly increase. While amorphous capacity today is currently less than the total distribution transformer total electrical steel usage, amorphous producers' response to the April 2013 Standards Final Rule demonstrates that if there was expected to be a market demand for amorphous steel, capacity would increase to meet that demand.

In interviews, several manufacturers noted that recent increases in prices, and foreign produced GOES prices, in particular, have led amorphous to be far more cost competitive. However, the industry has not necessarily seen an increase in amorphous transformer purchasing reflective of this pricing situation. Manufacturers noted that many of their processes are set-up to produce and process GOES steel and as such there is some degree of bias against amorphous transformers, regardless of what the first cost of a product is. In the August 2021 Preliminary Analysis TSD, DOE requested comment and data on the current amorphous core making capacity and the cost and time frame to add amorphous core production capacity. (August 2021 Preliminary Analysis TSD at p. 2–33)

In response, Metglas estimated amorphous core making capacity to be approximately 20,000 to 25,000 metric tons and noted that bringing on additional amorphous core manufacturing is relatively straightforward and inexpensive. (Metglas, No. 53 at p. 4) Metglas commented that there are conversion costs and capital costs associated with producing an amorphous core from amorphous steel laminations. (Metglas, No. 53 at p. 5) Eaton commented that the timeframe to add additional amorphous transformer capacity is dependent on whether additional design qualification testing is needed versus strictly capacity expansion and estimated one years for the former and one year for the latter. (Eaton, No. 55 at p. 11)

In the NOPR analysis, DOE has not applied any constraints to standard am steel purchasing in its evaluation of higher efficiency levels. DOE did constrain the selection of amorphous steel under the no-new-standards scenario to better match the current market share of amorphous distribution transformers, as discussed in section IV.F.2 of this document. DOE notes that any conversion costs associated with a transition from GOES production to amorphous distribution transformer production would be accounted for in the manufacturer impact analysis in section IV.J.

b. Grain-Oriented Electrical Steel Market and Technology

GOES is a type 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 thickness 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 different methods, some of which survive the distribution transformer core annealing process.

In the August 2021 Preliminary Analysis TSD, DOE identified four sub-categories of GOES as possible technology options. (August 2021 Preliminary Analysis TSD at p. 2–35) These technology options and their DOE naming short-hand are shown in Table IV.3.

TABLE IV.3—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 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. Power in the U.S. is delivered at 60 Hz and the flux 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 August 2021 Preliminary Analysis TSD, DOE identified several grades of GOES as potential technology options for distribution transformers. DOE requested comment and data on the availability of those steels, the ability to substitute various GOES grades for one another, any potential competition for steel supply for the large power transformer market, and the costs for steelmakers to add or convert capacity to higher performing GOES. (August 2021 Preliminary Analysis TSD at pp. 2–36–37)

Regarding potential competition for steel supply with the large power transformer industry, Schneider commented that power transformers and medium-voltage distribution transformers tend to be prioritized over the needs of the LVDT market and therefore supply issues can exist if LVDT manufacturers need to purchase the same core steel as medium-voltage distribution transformers. (Schneider, No. 49 at p. 14) Cliffs added that while high-permeability GOES works well in distribution transformers, it has historically been sold as a laser DR product to the power transformer market. (Cliffs, No. 57 at p. 1)

Conversely, NEMA suggested that electrical steels used in the large power transformer industry cannot be used in distribution applications, stating that the packaging and coating of steels targeting the large power transformer industry are not compatible with distribution transformer designs but added that large power transformers do compete for steel demand. (NEMA, No. 50 at p. 9)

Steel manufacturer literature generally markets GOES, and in particular hib and dr GOES, as suitable for use in either power or distribution transformers. Generally, a steel that is suitable for use in a power transformer may be suitable for use in a distribution transformer. As Schneider noted, and DOE confirmed in manufacturer interviews, power transformers tend to have priority and get the highest performing GOES. The industry also is volume driven and as such, the larger volume of the liquid-immersed market tends to be served before the dry-type distribution market.

Regarding availability of GOES more generally, NEMA recommended DOE review the DOC study for perspective on steel availability. (NEMA, No. 50 at p. 8) NEMA and Powersmiths commented that recently there has been a notable increase in competition from the auto industry for electrical steel to produce electric motors in EVs. (NEMA, No. 50 at p. 9; Powersmiths, No. 46 at p. 5) NEMA and Powersmiths stated that some steel suppliers are shifting part of their grain-oriented electrical steel production capacity to non-oriented electrical steel production—limiting the availability and increasing prices of transformer-grade steels. (NEMA, No. 50 at p. 9; Powersmiths, No. 46 at p. 5) At the Public meeting, a representative from Carte commented that one major foreign steel manufacturer transitioned 50 percent of their grain-oriented production lines to non-oriented. (Zarnowski, Public Meeting Transcript, No. 40 at p. 36) A representative from LakeView Metals, commented that the non-oriented market is skyrocketing and there is an estimated global shortfall of 13 silicon production lines. (Looby, Public Meeting Transcript, No. 40 at p. 37)

Powersmiths commented they are currently experiencing diminished availability of several grades of steel and increased costs as steel suppliers are shifting to serving the EV market without plans to bring transformer-grade steel capacity back. (Powersmiths, No. 46 at p. 5) ERMCO agreed that supply of steel is currently limited and they have been able to obtain M3 steel, some hib, and am steel. (ERMCO, No. 45 at p. 1)

Recent supply issues and increases in costs are likely associated with a combination of general commodity related supply chain issues and competition from electric vehicles. DOE notes that variability in electrical steel prices and supply is not new and historically, DOE averages prices to come up with a representative value. As part of the August 2021 Preliminary Analysis TSD, DOE did evaluate alternative price scenarios. DOE has applied a 5-year average price in its base case analysis and conducted sensitivities for various other pricing scenarios, as discussed in section IV.C.3. DOE has also screened-out some of the highest performing GOES, where steel manufacturers are not able to mass produce GOES of similar quality, as discussed in section IV.B.

NEMA previously noted that there is currently only one domestic producer of GOES and that the sole domestic producer does not have the capacity of high-grade electrical steel to serve the entire U.S. market, meaning the U.S. would be dependent on foreign electrical steel producers. (NEMA, No. 13 at p. 6–7)

Powersmiths commented that many of the high performing grades are only available from overseas suppliers and recent shipping and port access challenges have increased market uncertainty and availability to those grades. (Powersmiths, No. 46 at p. 6) Powersmiths stated that increased domestic capacity for GOES would require significant investment from industry and take years to come on. (Powersmiths, No. 46 at p. 6) Cliffs added that high-permeability GOES is a unique production line that would take years of planning, installation, and commissioning to convert existing M3 lines to high-permeability. (Cliffs, No. 57 at pp. 1–2) Cliffs stated that domestic steel is currently well-suited to serve distribution applications and higher standards would negatively impact the ability of domestic steel manufacturers to serve the distribution transformer market. (Cliffs, No. 57 at p. 2) Cliffs commented that higher efficiency levels would drastically hurt M3, and correspondingly domestic manufacturing, leaving the only domestic products as M2 and some high-permeability GOES grades. (Cliffs, No. 57 at p. 1) Cliffs commented that its electrical steel is produced with recycled steel scrap in an electric arc furnace, making it some of the greenest steel in the world. (Cliffs, No. 57 at p. 1)

DOE did constrain the selection of electrical steel under the no-new-standards scenario to better match the current market share of electrical steel, as discussed in section IV.F.2. In its evaluation of future standards, DOE assumed that steel manufacturers would provide the electrical steel qualities required by the market. In cases where fewer steel suppliers offer a grade of GOES, this is reflected by higher prices in DOE's analysis.

6. Distribution Transformer Production Market Dynamics

Distribution transformer manufacturers either make or buy transformer cores; some do both. Further, distribution transformer manufacturers may choose to produce transformers domestically or produce them in a foreign country and import them to the United States. 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. Each of these pathways has unique advantages and disadvantages which manufacturers have employed to maintain a competitive position.

First, manufacturers who produce distribution transformer cores and finished transformers domestically are able to maintain greater control of their lead times, potentially offering shorter lead times to their customers. This is particularly advantageous in servicing emergency applications with unique characteristics. This manufacturing approach is more common in certain liquid-immersed and medium-voltage dry-type applications, where customers may have unique voltage specifications that may not be routinely produced by all manufacturers but may be required on short notice.

As discussed, however, there is currently only one domestic manufacturer of grain-oriented electrical steel and one domestic manufacturer of amorphous steel. Under the current market dynamics with tariffs applied to all, raw imported electrical steel, these manufacturers are limited in where they can source their raw steel. As such, they may not have access to all of the types of steels available in the global market and may have different material prices from foreign core producers. While in theory, these manufacturers have the option to purchase electrical steel from foreign producers, they would be subject to the 25-percent tariff. Similarly, in theory, they have the option to purchase either grain-oriented electrical steel or amorphous electrical steel domestically.

DOE assumes that in the presence of amended standards, those manufacturers currently producing both cores and finished transformers domestically would still value the advantages of in-house domestic core production and would change their in-house production processes to accommodate the required core production equipment or required electrical steel grades.

Second, for manufacturers producing both the distribution transformer core and finished transformer in a foreign country and importing into the United States, they are able to control the in-house core production and therefore have similar advantages to those producing cores domestically. Further, because finished transformer imports are not currently subject to tariffs, they have access to the entire global market of electrical steel types and prices without the additional 25 percent tariff. However, these manufacturers may require increased management of electrical steel supply chains, as they are often purchasing electrical steel from overseas producers which may have longer lead times than sourcing electrical steel from domestic sources.

Similar to domestic manufacturers, DOE assumes that in the presence of amended standards, those manufacturers producing both cores and transformers outside the United States would still value the advantages of in-house core production and would change their in-house production processes to accommodate the required core production equipment or required electrical steel grades.

Third, manufacturers who purchase cores to manufacture distribution transformers are able to avoid the labor and capital equipment associated with producing transformer cores. In part for this reason, it is increasingly common among small businesses. Further, because distribution transformer cores are not subject to tariffs, purchasing cores also allows manufacturers to more easily transition between various steel grades and various steel suppliers, both international and domestic. Similarly, it is easier for manufacturers who outsource cores to transition between GOES and amorphous steel grades since it eliminates the need to use different core production equipment for each steel type as the process of converting a core into a transformer is relatively similar for both GOES and amorphous steels.

The primary disadvantages of outsourcing cores are that (1) transformer manufacturers may have less control over core, and therefore transformer, delivery lead times and (2) transformer manufacturers will pay a higher cost per pound of steel because they are purchasing partially processed products as compared to manufacturers who are producing their own cores.

DOE assumes that in the presence of amended standards, these manufacturers would switch from purchasing one grade of electrical steel core to a higher grade of electrical steel core.

In summary, DOE does not view any one of these core and transformer production pathways as necessarily becoming more advantaged or disadvantaged in light of the standards proposed in this notice relative to the present. In the current market, all three pathways act as viable options for manufacturers to find and maintain a competitive position. DOE does not have a reason to believe that the proposed standards would alter the ways in which distribution transformer manufacturers approach manufacturing or their current sourcing decisions given all three productions options continue to be available. DOE seeks comment on the distribution transformer market and whether the standards proposed will alter the current production pathways.

B. Screening Analysis

DOE uses the following five 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 working prototypes will not be considered further.

(2) *Practicability to manufacture, install, and service.* If it is determined that mass production and reliable installation and servicing of a technology in commercial products 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 or product availability.* If it is determined that a technology would have a significant adverse impact on the utility of the product for significant subgroups of consumers or would 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) *Adverse impacts on health or safety.* 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 design option utilizes proprietary technology that represents a unique pathway to achieving a given efficiency level, that technology will not be considered further due to the potential for monopolistic concerns.

10 CFR 431.4; 10 CFR part 430, subpart C, appendix A, sections 6(b)(3) and 7(b) (''Process Rule'').

In summary, 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 August 2021 Preliminary Analysis TSD, DOE identified core deactivation as a potential technology option to improve efficiency but noted that it was not a generally accepted practice and would be associated with system wide savings, not savings as measured by DOE's test procedure.

In response, NEMA commented that core deactivation would only be beneficial in certain settings and there are questions of reliability associated with shifting load which could lead to shorter lifetimes. (NEMA, No. 50 at p. 7) NEEA commented that core deactivation may impact maintenance of switchgear and other connected equipment. (NEEA, No. 51 at p. 5)

Due to the concerns cited by NEMA and NEEA regarding impacts on product lifetime and servicing of equipment, along with the fact that core deactivation would not impact the efficiency as measured by the DOE test procedure, DOE has screened-out core deactivation as a potential technology option.

DOE also identified less-flammable insulating liquid-immersed distribution transformer (''LFLI'') as a potential technology by which manufacturers could increase the capacity of a distribution transformer without increasing the size, potentially leading to energy savings. In response, NEMA commented that while LFLI is used by some customers to reduce unit size, particularly for pad mounts but rarely for pole mounts, it is generally pursued for greater reliability and not greater efficiency. (NEMA, No. 50 at pp. 7–8)

DOE notes that while there may be opportunity for a customer to maintain distribution transformer lifespan while increasing the loading on a transformer with LFLI technology, this would not impact the efficiency as measured by DOE's test procedure. Further, DOE understands that there are potential consumer safety concerns with distribution transformers operating notably hotter, namely that the touch temperature could be too high for consumers to safely interact with. Therefore, DOE has screened out LFLI as a potential technology option.

Regarding evaluating efficiency improvements associated with certain high-performing GOES grades, Powersmiths commented that the stability of availability, cost, and batch quality of some new steel grades is unproven. (Powersmiths, No. 46 at p. 5) Schneider expanded that steel mills are not perfectly consistent and only a portion of their production may meet a target loss performance. As such, it may not be feasible to set efficiency levels based on premium grades, for example an 075 or 070 grade steel, as steel manufacturers may not be able to consistently achieve the premium performance. (Schneider, No. 49 at p. 14) Schneider added that some higher performance steels are published in steel maker catalogs but are not widely available for commercial use. (Schneider, No. 49 at p. 13)

In GOES production, the product steel losses can vary somewhat between and within batches. Because of this variability in electrical steel, producers typically offer two loss specifications for their steels, a guaranteed core loss and a typical core loss. While some of the premium products identified in the August 2021 Preliminary Analysis TSD generally exist and are used in the market, they represent the upper end of the distribution of product performance. As commenters suggested, without further improvements in consistency of batch quality, it may not be reasonable to assume these products could be widely used in industry. Therefore, DOE has screened out certain high-performing GOES products. Specifically, DOE removed 23pdr075 and 20dr070 electrical steels from its engineering modeling due to concerns with its practicability to manufacture. DOE notes that these electrical steels could be used in certain applications but DOE has screened them out because of concerns that mass production of these products could not be achieved on the scale necessary to serve the distribution transformer market.

DOE listed several other technology options in the August 2021 Preliminary Analysis TSD for which it did not receive any comment. As such, DOE has retained those technology options as screened out.

Technology options screened out are listed in Table IV.4 with their bases for screening.

TABLE IV.4—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 tentatively concludes that the remaining combinations of core steels, windings materials 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 NOPR analysis.

DOE has initially determined that these technology options are technologically feasible because they are being used or 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 and do not result in adverse impacts on consumer utility, product availability, health, or safety, unique-pathway proprietary technologies). For additional details, see chapter 4 of the NOPR TSD.

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 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. Representative Units

Distribution transformers are divided into different equipment classes, categorized by the physical characteristics that affect equipment efficiency. DOE's current energy conservation standards at 10 CFR 431.196 divide distribution transformers based on the following characteristics: (1) capacity (kVA rating), (2) voltage rating, (3) phase count, (4) insulation category (*e.g.,* ''liquid-immersed''), and (5) BIL rating.

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 specification to enable generalization of the results. In the August 2021 Preliminary TSD, DOE presented 14 representative units and noted they were unchanged from the April 2013 Standards Final Rule. (August 2021 Preliminary TSD at p. 2–41)

In response to the August 2021 Preliminary TSD, Howard commented that RU3 is not a very good representative unit because it is not common and should be replaced with a more common unit. (Howard, No. 59 at p. 2) DOE agrees that RU3, corresponding to a 500 kVA, single-phase, liquid-immersed distribution transformer, is generally larger than the more common capacities included in equipment class 1. However, as noted, DOE's RUs are designed to include both common units and units included to improve generalization. RU3 is included to improve scaling of results to the larger units within the scope of equipment class 1. Therefore, RU3 has been retained in this NOPR.

Carte commented that the representative units used by DOE are representative of common/typical sizes but the extremes were not analyzed, where meeting efficiency standards tend to be the hardest. (Carte, No. 54 at p. 1) Carte added that certain designs are forced to use high-end grain-oriented electrical steel and copper windings or in certain cases are unable to be met by Carte. (Carte, No. 54 at p. 1)

Eaton commented that the representative units are good choices for the highest volume transformers, however, as efficiency standards increase, efficiency standards may not be achievable at the scope extremes. (Eaton, No. 55 at p. 12)

It is true that certain extreme designs may have more difficulty achieving efficiency standards while still being requested by consumers. Most applications would generally be able to use amorphous steel to achieve higher efficiencies, including at efficiency levels beyond DOE's max-tech. DOE selected design units to include both large and small distribution transformers across the various representative units and DOE's modeling of the selected representative units includes amorphous designs which achieve efficiencies above DOE's max-tech for all RUs. This indicates that there is room for even extreme designs to meet efficiency standards using technologies modeled by DOE.

DOE requests data demonstrating any specific distribution transformer designs that would have significantly different cost-efficiency curves than those representative units modeled by DOE.

To assess the impact of expanding the scope of the definition of ''distribution transformer'' in 10 CFR 431.192 to include distribution transformers up to 5,000 kVA, DOE is evaluating three new

RUs. DOE scaled the results for RU5, RU12, and RU14 to represent RU17, RU18, and RU19, respectively, each of which are rated at 3,750 kVA. Results were generated for RU17, RU18, and RU19 using the scaling rules for dimensions, transformer weight, no-load losses, load losses, etc., as described in Appendix 5C of the TSD.

DOE notes that it only includes distribution transformers in the downstream analysis that would meet or exceed current energy conservation standards. Because RU17, RU18, and RU19 represent an expansion in scope, they are not currently subject to energy conservation standards. As such, all modeled designs are included in the downstream analysis, regardless of efficiency and DOE relies on the consumer choice model to determine the efficiency of distribution transformers selected at baseline. DOE has described these results and shown the cost-efficiency curves for these scaled units in Chapter 5 of the TSD.

DOE requests comment on its methodology for scaling RU5, RU12, and RU14 to represent the efficiency of units above 3,750 kVA.

Distribution transformers designed for submersible applications may be disadvantaged in meeting efficiency standards on account of having to meet efficiency standards with reduced cooling ratings. To explore this specification limitation, DOE has proposed a definition for submersible distribution transformers. In this NOPR, DOE is evaluating those submersible distribution transformers as a separate equipment class. DOE has modified the engineering results for RU4 and RU5 to represent two new RUs, RU15 and RU16. RU15 and RU16 represent common three-phase submersible distribution transformers. To account for the thermal derating that is associated with submersible distribution transformers, DOE evaluated RU15 and RU16 as having their nameplates derated by one standard kVA size relative to the efficiency of RU4 and RU5. That is, while RU4 is a 150 kVA three-phase, liquid-immersed distribution transformer, RU15 is a 112.5 kVA three-phase, liquid-immersed, submersible distribution transformer. Similarly, while RU5 is a 1,500 kVA three-phase, liquid-immersed distribution transformer, RU16 is a 1,000 kVA three-phase, liquid-immersed distribution transformer. DOE calculated the efficiency of RU15 and RU16 based on their new nameplate and assuming no-load losses are the same and load losses scale with the quadratic of load. DOE also modified the cost of the tank material from carbon steel to stainless steel to represent the corrosion resistant properties of submersible distribution transformers. All other physical properties of the distribution transformer are the same.

DOE requests comment on its methodology for modifying the results of RU4 and RU5 to represent the efficiency of submersible liquid-immersed units. For other potentially disadvantaged designs, DOE has considered establishing equipment classes to separate out those that would have the most difficulty achieving amended efficiency standards, as discussed in section IV.A.2, but ultimately has determined not to include such separate equipment classes in the proposed standards. However, DOE requests data as to the degree of reduction in efficiency associated with various features.

2. Efficiency Analysis

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

Howard commented that there were inconsistencies in the efficiency levels presented in the webinar and the August 2021 Preliminary Analysis TSD. (Howard, No. 59 at p. 2) DOE notes that corrected values are presented in this analysis.

In this rulemaking, DOE relies on 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 designs by contracting with Optimized Program Services, Inc. (''OPS''), a software company specializing in distribution transformer design. The OPS software used two primary inputs: (1) a design option combination, which includes core steel grade, primary and secondary conductor material, and core configuration, and (2) a loss valuation.

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

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

From the OPS software, DOE received thousands of different distribution transformer designs, including physical characteristics, loading and loss behavior, and bill of materials. DOE used these distribution transformer designs, supplemented with confidential and public manufacturer data, to create a manufacturer selling price (''MSP''). The MSP was generated by applying material costs, labor estimates, and various mark-ups to each design given from OPS.

The engineering result included hundreds of unique distribution transformer designs, spanning a range of efficiencies and MSPs. DOE used this data as the cost versus efficiency relationship for each representative unit. DOE then extrapolated this relationship, generated for each representative unit, to all the other, unanalyzed, kVA ratings within that same equipment class.

In the August 2021 Preliminary Analysis TSD, DOE stated that it maintained the existing designs from the previous rulemaking and updated the material prices to get an updated manufacturer selling price. (August

2021 Preliminary Analysis TSD, at p. 2–45)

Howard commented that while updating pricing to $2020 still gives valid designs, reoptimizing with new pricing would have given more accurate results. (Howard, No. 59 at p. 2)

DOE agrees that the most accurate results would be achieved by reoptimizing designs under current market practices. However, as commenters have attested, prices for many of the components making up distribution transformers are varied. Further, manufacturers may make different optimization decisions depending on their unique supply chains and manufacturing capacities. It would be impractical for DOE to reoptimize all designs with every change in material prices and to represent the specific supply chains of each manufacturer. To account for the variability in designs, DOE relies on a wide range of A and B values to initially develop designs reflective of the whole design space, not specific to any given day's pricing. DOE relies on 5-year average material pricing in its base analysis and conducts additional sensitivities to encompass additional pricing scenarios. Further, DOE's analysis of various efficiency levels includes a consumer choice model that selects a sub-set of designs based on the minimum MSP within a band-of-equivalence for a given efficiency level. As such, DOE's efficiency levels are not reflective of any one distribution transformer, but rather are designed to reflect the variety of distribution transformers customers would purchase at a given efficiency level.

In the August 2021 Preliminary Analysis TSD, DOE noted that it adapted models of grain-oriented electrical steel to reflect some of the lower loss steels that have come onto the market since the previous rulemaking. Specifically, DOE stated that it estimated the core loss of a similar design by multiplying the no-load loss by the ratio of the core losses at a given flux density between two steels. DOE noted that while these designs would not be true optimal designs, given that lower loss steel allows more flexibility in the load losses, however, stated that because DOE's designs cover such a wide range of A and B values, the results would be sufficiently accurate. DOE requested feedback on this approach. (August 2021 Preliminary Analysis TSD at p. 2–46)

Schneider commented that assuming the core losses of a swapped steel may be accurate for small reductions in core loss but bigger jumps could result in full redesigns. (Schneider, No. 49 at pp. 14–15) Powersmiths and ERMCO commented that this approach does not lead to optimized designs. (Powersmiths, No. 46 at p. 4; ERMCO, No. 45 at p. 1) NEMA commented that it is an oversimplification to assume that substituting of lower loss steel will lead to improved efficiency for a given design. (NEMA, No. 50 at p. 10) NEEA commented that DOE should not use this approach because new material may have different B–H curves and while it may be possible to use a direct swap—it generally isn't an acceptable practice. (NEEA, No. 51 at pp. 5–6) The Efficiency Advocates recommended DOE conduct new modeling as manufacturers who didn't optimize for new material would be at a competitive disadvantage. (Efficiency Advocates, No. 52 at pp. 6–7)

In response to stakeholder feedback, DOE ran new modeling for some design option combinations included in the NOPR. DOE compared this new modeling to its models that were established by swapping core steels and has presented some of these comparisons in chapter 5 of the TSD. DOE notes that modeled designs may be slightly different at a given A and B value as compared to the direct swap of core steels. However, across the range of A and B values included in the engineering analysis, and specifically at the minimum MSP for a given efficiency, the cost-efficiency curves are very similar. While DOE intends to update all the engineering designs to newly modeled designs to instill greater confidence in the analysis, some core steel swap designs are still used in the NOPR in order to ensure quick publication of the NOPR. These designs are noted in chapter 5 of the TSD. Given the similarities between the modeled designs and the direct swap of steel designs, DOE believes the updated modeling will not notably impact analysis results.

a. Design Option Combinations

As discussed, for each representative unit, DOE evaluates various design option combinations, which includes combinations of electrical steel, conductor material, and core construction techniques. In the August 2021 Preliminary Analysis TSD, DOE presented the various design option combinations it used for each representative unit. DOE noted that distributed gap wound cores typically need a high-temperature annealing process to relieve some of the stresses associated with the core winding process. (August 2021 Preliminary Analysis TSD at p. 2–46) As a result of this annealing, laser-scribed domain-refined steels lose the core loss benefit of the domain-refinement. As such, DOE did not include any laser-scribed domain-refined steels in distributed gap wound core design option combinations. DOE requested comment on this decision.

In response, NEMA and Schneider supported DOE's decision not to include laser DR products in wound core constructions. (Schneider, No. 49 at p. 15; NEMA, No. 50 at p. 11) Similarly, Eaton agreed with DOE's decision not to include laser-scribed domain-refined steels in wound cores but noted that larger, three-phase units may be able to use laser-scribed domain-refined steels in wound cores if an AEM Unicore machine is used and the products are not annealed. (Eaton, No. 55 at p. 13)

DOE agrees with Eaton that in certain scenarios it may be possible to use laser-scribed dr products in wound core. But as Eaton described, the dr characteristics are only maintained if the core is not annealed. An unannealed core is going to have greater losses associated with the stresses from the bending of the electrical steel. So, the loss reduction associated with the better performing laser dr product is going to be countered by increased losses associated with stresses from bending the steel without annealing. As such, this approach does not necessarily reflect a higher efficiency product, but rather a similar performing product to using hib steel without domain-refinement and annealing the core. DOE did not receive any opposition to its decision to not include laser-scribed dr steels in its wound core designs and therefore maintained that approach in the NOPR analysis.

Regarding some of the specific design option combinations presented in the August 2021 Preliminary Analysis TSD, NEMA commented that GOES with performance lower than M4 is not used due to performance limitations. (NEMA, No. 50 at p. 8) Eaton commented that M5 isn't really used anymore and can be removed from RU4 engineering plots. Eaton also commented that M4 isn't really used in RU5 designs and can be removed from DOE's engineering plots. (Eaton, No. 55 at p. 20) Eaton commented that an Evans core transformer is not a valid option for wye-wye distribution transformers but noted that it was a moot point since the costs are greater. (Eaton, No. 55 at p. 20)

DOE acknowledges that some designs would be unlikely to be considered by many purchasers, but the engineering analysis is designed to explore the whole design space. The specific combinations identified by NEMA and

Eaton generally do not impact the analysis due to the first-cost of the product being too high and are included for completeness of the analysis.

Regarding use of thinner steels, NEMA commented that thinner GOES is more difficult to use, but not overly burdensome, whereas amorphous is a different thickness and width and cannot be dropped in. (NEMA, No. 50 at p. 9) Cliffs added that while there are specific applications where M2 is suitable, nearly all EOMS have stated it is not amenable to their manufacturing processes as it is thin and prone to folding and tearing in core making equipment. (Cliffs, No. 57 at p. 1)

DOE includes additional costs associated with handling of thinner electrical steels, as described in chapter 5 of the TSD. While M2 is included in the analysis, DOE has limited its selection in the base case scenario as described in section IV.F.3.a to be reflective of its current market share. In the presence of higher standards, M2 steel (or similarly performing hib steel that wasn't modeled but has similar performance may be an option), may be a feasible design option for manufacturers although, it may not be the lowest first cost option.

Regarding the burdens with using amorphous steel, DOE has considered those costs in the manufacturer impact analysis in section IV.J of this document.

Eaton noted that while DOE's designs span the current definition for normal impedance range, if new designs are run in the future, a narrower impedance range should be used for RU4 and RU5 to align with IEEE C57.12.34, as too low an impedance could permit extremely high fault current in the event of a short circuit. (Eaton, No. 55 at p. 16)

As Eaton noted, DOE's impedance ranges align with the current definition for normal impedance range. The narrower impedance range cited by Eaton are achievable in DOE's models by all efficiency levels. DOE believes aligning with the definition of normal impedance range remains appropriate given that a variety of impedances are included at each efficiency level and consumers may specify specific impedances.

b. Data Validation

In the August 2021 Preliminary Analysis TSD, DOE stated that it had collected publicly available bid data for a variety of distribution transformers. DOE noted that the data was limited in its ability to compare cost and efficiency because the data was limited to liquid-immersed distribution transformers, there was significant variability in primary voltages, the data didn't span the whole design space in all cases, much of the data was prior to implementation of the energy conservation standards as amended in the April 2013 Standards Final Rule (Effective January 1, 2016), and there was significant price variability at every efficiency. (August 2021 Preliminary Analysis TSD at p. 2–45) Rather than drawing any conclusions from this data, DOE relied on the reported no-load loss and full-load loss to estimate efficiency. DOE then presented the raw material prices and attempted to correct the material prices to show.

The Efficiency Advocates commented that the bid data shows significant differences in MSP and indicates that the engineering analysis need to be updated to reflect up-to-date materials, costs, and designs. (Efficiency Advocates, No. 52 at p. 7) Eaton commented that the average selling price in the plots comparing bid data and DOE engineering show average selling prices being much higher than DOE's analysis suggests. (Eaton, No. 55 at p. 22)

DOE is uncertain what significant difference in MSP the stakeholders are referring to as there is a wide range in the bid data and many of the points overlap between the bid data and DOE designs. Regardless, DOE has updated material costs in the NOPR analysis.

In presenting the bid data, DOE noted that it only has full load efficiency at rated operating temperature, and therefore applied a quadratic scaling and estimated temperature correction to estimate the efficiency as measured according to DOE's test procedure.[49]

Eaton commented that DOE's estimate for correcting the load loss in the bid data is insufficient. (Eaton, No. 55 at p. 20) Eaton expressed concern that a similar method was used to calculate DOE's 50 percent load loss values from the 100 percent load loss values. (Eaton, No. 55 at p. 20)

DOE did not use the same method to calculate 50 percent load loss values from the 100 percent values in it modeled data, it only did this in the bid data because the bid data did not have specifics as to how the equipment temperature varies with load and temperature correction was simply to estimate efficiency for a general comparison. DOE's modeled data included estimated load performance and temperature at a variety of transformer load points. DOE relied on the modeled transformer load loss at 50 percent load and corrected from the modeled operating temperature to DOE's reference temperature.

Rather than trying to estimate the rated efficiency of the public utility bid data from full load losses at rated temperature rises and make generalization as to how temperature would influence efficiency at rated PUL, DOE has looked at how the no-load and full load losses of the bid data compare to the full load losses of the DOE modeled data. These comparisons are shown in chapter 5 of the TSD. The comparisons show that DOE's modeled data aligns well with the design space of the public utility bid data.

In comparing DOE's modeled results to the public utility bid data, DOE realized that for RU4 and RU5, DOE models overestimated GOES no-load losses, and accordingly assumed manufacturers would need lower load losses in order to meet efficiency standards.

The process of converting electrical steel from a sheet into a formed core shape incurs some number of additional losses, known as a destruction factor. Eaton commented that when comparing amorphous laminations to a finished core, the destruction factor can be non-trivial and contribute an additional 40 percent to the core losses. (Eaton, No. 55 at p. 11) Similarly, in GOES cores, the destruction factor can be significant and varies by transformer type, manufacturing technique, and electrical steel type. In general, destruction factors are much more significant for three-phase distribution transformers than single-phase distribution transformers.

The destruction factor for three-phase wound core designs was originally chosen to be conservative and assume manufacturers would have higher destruction factors. Through interviews, DOE learned that manufacturers may be able to reduce destruction factors in wound cores using a Unicore design, and this is more common in larger, three-phase designs which tend to be produced in lesser volumes. In the NOPR analysis, DOE modified the destruction factor of three-phase, liquid-immersed, wound core, GOES distribution transformers to better align with the marketed Unicore destruction factors.[50] The resulting designs better align with the actual design space observed in real world data, as shown in chapter 5 of the TSD. The impact of this change is that GOES transformers achieve higher efficiency ratings for RU4 and RU5 than the August 2021

[49] See Chapter 5 of the NOPR TSD, available online at *www.regulations.gov/document/EERE-2019-BT-STD-0018-0022.*

[50] Advertised destruction factors for Unicore available at *www.aemcores.com.au/technology/annealing/overview-and-the-benefit-of-unicore/.*

Preliminary Analysis TSD suggested. It also introduces new transformers to the selectable design space which may have a lower MSP than if DOE had not made this change. While destruction factor does vary by manufacturing technique and manufactures may use different methods, DOE believes that absent this change, it would be overestimating the cost of meeting efficiency standards with a GOES core as compared to an amorphous core.

Regarding DOE's use of modeling software, Powersmiths commented that OPS software is used by them and many manufacturers but noted that the eddy and stray losses in OPS models are ''guestimates'' from the design engineer and can vary largely. (Powersmiths, No. 46 at pp. 4–5) Powersmiths commented that inadequate stray loss estimates could result in simulation errors and should be examined more closely relative to transformer capacity. (Powersmiths, No. 46 at p. 5)

NEMA commented that its members' modeling programs account for stray, eddy, and other losses that appear largely absent from DOE models and while this was noted in the April 2013 Standards Final Rule, the efficiency levels in the preliminary analysis leave little flexibility to meet efficiency standards, making it more important now. (NEMA, No. 50 at p. 2) NEMA added by omitting these design factors, DOE's models do not represent true design feasibility and DOE should update models to add these losses. (NEMA, No. 50 at p. 2) NEMA commented specifically that in applications with a large amount of buss bars are required, efficiency standards are more difficult to meet. (NEMA, No. 50 at p. 5)

DOE transformer models do include estimates of stray and eddy losses. As commenters noted, the amount that these impact designs will be unique to manufacturer and specific transformer designs. In DOE's comparison of its liquid immersed designs to the design space in public utility bid data, DOE notes that its designs align relatively well with what is being built on the market. Further, DOE includes a bus and lead correction factor to MVDT designs based on an understanding that substation-style designs are quite common in the MVDT market.

DOE requests data as to how stray and eddy losses at rated PUL vary with kVA and rated voltages.

While certain unique designs may have higher stray and eddy losses, the incremental costs with meeting higher efficiency standards tends to follow a similar relationship. Particularly to the extent that amended efficiency standards are met via a transition to lower-loss GOES or amorphous steel, the incremental cost to meet higher efficiency standards tends to be similar. In bid data, DOE observed that higher current transformers, which are more likely to have high stray losses, often have more amorphous bids. This suggests that transformers with high buss losses may have more favorable economics associated with meeting amended efficiency standards via amorphous steel.

Regarding validation of DOE's engineering analysis more generally, NEMA commented that its members cannot validate and offer corrections for every RU but suggested DOE hold a series of collaborative meetings where models are made more accurate and representative. (NEMA, No. 50 at p. 2) Eaton requested DOE provide more information about the distribution transformer design so manufacturers can confirm the designs align with their modeling. (Eaton, No. 55 at p. 20–22)

DOE has included additional engineering details in chapter 5 of the TSD to better explain its modeling and costing. Regarding NEMA's suggestion to hold collaborative meetings, DOE notes that in addition to soliciting public comment in a written format and public interviews, DOE conducts confidential manufacturer interviews through which manufacturers are invited to offer feedback. DOE has in the past, and as part of this analysis, made updates to its modeling to better reflect manufacturer realities. DOE will continue to update its analysis in response to manufacturer feedback and particularly to the extent modeling deviates from real world design constraints.

c. Baseline Energy Use

For each equipment class, DOE generally selects a baseline model as a reference point for each class, and measures changes resulting from potential energy conservation standards against the baseline. 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 levels are discussed in section IV.F.3 of this document.

d. Higher Efficiency Levels

DOE relies on a similar approach to its baseline engineering in evaluating higher efficiency levels. DOE's modeled units span the design space. In evaluating a higher efficiency level up until that maximum efficiency level that DOE considers (''max-tech''), 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 transformers that would be purchased if standards were amended.

Howard commented that they looked at the various RUs and believe the current efficiency standards provide excellent value to consumers. (Howard, No. 59 at p. 2) Howard added that while they don't use OPS software, their internal software says to remain at the current efficiency levels and there is no need to have a NOPR as current standards are sufficient. (Howard, No. 59 at pp. 2–3) DOE appreciates Howard's comment but notes that they have not provided data to justify the results of their internal software. As noted previously, DOE has tentatively determined that the proposed standards are technologically feasible (based on models currently available in the market) and economically justified, and would result in significant energy savings.

The Efficiency Advocates commented that since DOE last revised its energy conservation standards, major economies around the world have set new efficiency thresholds that exceed U.S. energy conservation standards. (Efficiency Advocates, No. 52 at pp. 7–8) The Efficiency Advocates commented that the U.S. should aim to be a world leader in transformer efficiency. (Efficiency Advocates, No. 52 at pp. 7–8)

DOE notes that while it may look at foreign efficiency standards to get a better understanding of the global distribution transformer market, the U.S. has its own unique economic conditions, energy costs, and legal requirements. DOE has evaluated amended energy conservation standards based on the unique conditions of the U.S. and DOE's legal obligations under EPCA.

e. Load Loss Scaling

DOE energy conservations standards apply only at a single PUL for a given distribution transformer equipment class (50 percent for liquid-immersed distribution transformers and medium voltage dry-type distribution transformers and 35 percent for low-voltage dry-type distribution transformers). 10 CFR 431.196. However, distribution transformers exhibit varying efficiency with varying PUL. Distribution transformer no-load losses are generally constant with loading, while load losses vary approximately with the quadratic of the PUL. In practice, efficiency deviates slightly from this assumption as no-load losses are not perfectly constant and load losses are not perfectly quadratic. DOE requested comment on approximating load losses as a quadratic function of PUL.

NEMA commented that the quadratic approximation for load losses is sufficient. (NEMA, No. 50 at p. 11)

OPS' modeling includes details as to how a distribution transformer's loss and temperature vary across select load points. In determining the rated efficiency of a transformer model as it would be certified under DOE's test procedure, DOE relies on the modeled load losses at the PUL at which efficiency is calculated and corrects the load losses from the modeled temperature to the reference temperature. This value is used to calculate the rated efficiency of a distribution transformer model.

In the downstream analysis of a distribution transformer energy use and costs, DOE relies on the calculated full-load loss values and applies a quadratic approximation for what the load losses would be under real world loading conditions. Commenters have generally agreed that this approach is sufficient.

DOE noted that the full-load loss value DOE uses in its downstream analysis is the full-load loss estimate at the modeled transformer temperature. Full-load loss in industry is often reported at the rated temperature rise. Lower loss distribution transformers generally operate at lower temperatures, as they have less losses of heat to dissipate. Some transformers may operate well below their rated temperature even at full load. Therefore, the full-load losses used in the downstream analysis may be lower than the reported full-load losses at rated temperature rise.

NEEA commented that a quadratic scaling of load losses would not apply with harmonic frequencies and DOE should include a harmonic dependent factor in its scaling model. (NEEA, No. 51 at p. 6) DOE notes that section 4.1 of appendix A specifies testing using a sinusoidal waveform. Therefore, harmonics would not impact the rated efficiency of a distribution transformer.

In DOE's downstream analyses, harmonics would generally lead to greater losses. While nonlinear loads exist, the impact of them is small and DOE does not have data suggesting they meaningfully impact system wide savings to the point that a quadratic approximation is inaccurate. Further, while harmonics may increase losses, relative to what a quadratic approximation would estimate, lower operating temperatures at low-loading, where most distribution transformers operate, would decrease losses relative to the quadratic approximation.

While other factors may cause the loss behavior of individual transformers in specific applications to deviate slightly from a true quadratic of the full-load losses, stakeholders have generally supported approximating load losses a quadratic of PUL and have not provided an alternative, more accurate method for approximating losses. As such, DOE has retained a quadratic load loss scaling in its analysis.

f. kVA Scaling

NEMA commented that the 0.75 power scaling rule is overly simplistic and has resulted in smaller kVA MVDTs having a hard time meeting efficiency standards. (NEMA, No. 50 at p. 9) Eaton commented that DOE's scaling rule as it applied to height, width, and depth of the core/coil assembly would not always be accurate due to certain bushing space requirements and design trade-offs pertaining to bushing heights relative to core/coil assembly heights. (Eaton, No. 55 at p. 16)

DOE has not received any comment or data suggesting an alternative method for scaling kVA and therefore has retained its scaling methods.

3. Cost Analysis

The cost analysis portion of the engineering analysis is conducted using one or a combination of cost approaches. The selection of cost approach depends on a suite of factors, including the availability and reliability of public information, characteristics of the regulated product, 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 (for example, for tightly integrated products such as fluorescent lamps, which are infeasible to disassemble and for which parts diagrams are unavailable) or cost-prohibitive and otherwise impractical (*e.g.,* large commercial boilers), DOE conducts price surveys using publicly available pricing data published on major online retailer websites and/or by soliciting prices from distributors and other commercial channels.

In the present case, DOE conducted the analysis by applying materials prices to the distribution transformer designs modeled by OPS. The resulting bill of materials provides the basis for the manufacturer production cost (''MPC'') estimates to which mark-ups are applied 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. DOE presented preliminary costing data and methodology in the August 2021 Preliminary Analysis TSD.

Regarding the cost analysis generally, NEMA commented that the material prices presented in the preliminary analysis do not reflect the post-COVID world and may be low by as much as half. (NEMA, No. 50 at p. 2) Eaton commented that PPI for power and distribution transformers has increased around 25 percent from 2020 levels and so costs are going to be higher and payback periods will be longer. (Eaton, No. 55 at p. 13) Howard echoed the concerns that Covid–19 has created labor and supply chain issues. (Howard, No. 59 at p. 1) Howard commented that their internal studies showed incremental MSPs as much as four times higher than what DOE showed in their preliminary analysis. (Howard, No. 59 at p. 2) Carte commented that the cost of both copper and aluminum have risen substantially in the past year. (Carte, No. 54 at pp. 3–4) Powermiths added that market megatrends, such as the pandemic, decarbonization and electric vehicles may impact the analysis and create uncertainty. Powesmiths recommended DOE delay changes until these megatrends settle. (Powersmiths, No. 46 at pp. 6–7) Powersmiths and Carte commented that the market is in a state of flux right now and it may be prudent to hold off any changes to efficiency standards until prices settle. (Carte, No. 54 at p. 4; Powersmiths, No. 46 at p. 7)

DOE data confirms that prices have been up recently, however, it is difficult to say for certain how those prices will vary in the medium to long terms and what those prices will be in the future. Rather than trying to project future prices, DOE relies on a five-year average in its base case and evaluates how the results would change with different pricing sensitivities. The recent price increases described by comments are incorporated into this five-year average and as a result, prices in the NOPR analysis are higher than they were in the August 2021 Preliminary Analysis TSD.

Eaton commented that in evaluating amended energy conservation standards, DOE should solicit quotations from at least three distribution transformer manufacturers for each representative unit and create a cost-down cost estimate to calibrate the bottom-up estimates. (Eaton, No. 55 at p. 19)

As DOE noted in section IV.C.2.b, DOE welcomes manufacturers to submit design and costing data for distribution transformers. DOE notes that in addition to soliciting public comment in a written format and public interviews, DOE conducts confidential manufacturer interviews through which much of the pricing data is gathered. DOE has made some updates to its cost analysis in response to manufacturer feedback, as described in the following sections.

a. Electrical Steel Prices

Electrical steel is one of the primary drivers of efficiency improvements and the relative costs associated with transitioning to lower loss steels can impact the cost effectiveness of amended efficiency standards. As noted, in section IV.A.5, the sourcing practices of individual manufacturers and production locations can impact prices as not all steel manufacturers produce the same electrical steels and trade actions have historically impacted the industry. DOE presented pricing in the August 2021 Preliminary Analysis TSD and requested comment. (August 2021 Preliminary Analysis TSD at p. 2–53)

ERMCO commented that the core steel costs presented in the preliminary analysis seem reasonable, but market growth in sectors, like EVs, may drive future prices up. (ERMCO, No. 45 at p. 1) Powersmiths commented that smaller manufacturers cannot access the DOE costs because volume drives price. Powersmiths noted that for one of the pdr steels it uses, the price has increased as much as 61 percent and they do not see them returning to their lower prices. (Powersmiths, No. 46 at p. 6)

Carte commented that there is a global shortage of electrical steel and the price is up 20 percent in this year alone, with current prices up 76 percent from the 2008 peak. (Carte, No. 54 at p. 3) Carte noted that some industry sources expect prices to far exceed their 2008 peaks. (Carte, No 54 at p. 3)

Carte cited several reasons for the increase in pricing. China has reduced export of GOES in recent years. (Carte, No. 54 at p. 3) Second, increased competition from non-oriented electrical steel serving the electric vehicle industry which has encouraged some steel manufacturers to convert GOES production lines to non-oriented electrical steel production lines. (Carte, No. 54 at p. 3)

DOE has updated pricing in this analysis in response to stakeholder feedback and confidential manufacturer interviews. Prices for electrical steel have increased significantly in recent years. Manufacturers noted that this price increase was particularly high for foreign electrical steel. DOE has applied a 5-year average price in its base case analysis. The prices in and conducted sensitivities for various other pricing scenarios, as discussed in section IV.C.3.

EEI commented that higher standards may significantly impact all non-amorphous cores and limit choice and lead to higher prices for consumers considering limited availability of certain steel. (EEI, No. 56 at p. 3)

DOE generally assumes pricing to be reflective of current market costs. While higher standards could limit which steels are available to meet standards, DOE notes that a handful of high-volume steels currently dominate the industry. Historically, when amended standards have been adopted, steel manufacturers have increased capacity of the electrical steel grades needed to meet amended efficiency standards. These materials may have higher costs, but they also tend to have higher costs in the current market. Rather than trying to predict what the cost and market breakdown would be in the presence of amended standards, DOE relies on a five-year average and conducts price sensitivities to ensure that energy savings are cost effective under different pricing structures.

Carte commented that while they don't purchase amorphous steel, DOE may want to verify that amorphous steel from China is still available and questioned if there were any domestic manufacturers of amorphous steel. (Carte, No. 54 at p. 3) DOE notes that amorphous steel is produced domestically, as well as in China and Japan.

NEEA commented that its research suggests amorphous cores are lower first cost above 100 kVA single-phase or 500 kVA three-phase and there are several utilities commonly purchasing amorphous in the U.S. and Canada. (NEEA, No. 51 at p. 8) Metglas commented that its internal calculations show that amorphous steel is not close to price parity with GOES, using DOE's preliminary analysis assumed pricing. (Metglas, No. 53 at p. 2) Metglas commented that recent bid data shows amorphous transformers typically need an A value over $7 per Watt and A to B ratio greater than $3 per Watt for amorphous transformers to win on total ownership cost bids. (Metglas, No. 53 at p. 2) Metglas commented that DOE's preliminary analysis pricing of amorphous is accurate for sourced cores, but may be lesser for manufacturers who produce their own cores. (Metglas, No. 53 at p. 5)

Metglas commented that some transformer manufacturers source cores while other produce them internally. (Metglas, No. 53 at p. 5) NEMA disagreed with DOE's assumption that all amorphous cores are sourced and deferred to individual NEMA members as to their specific practices. (NEMA, No. 50 at p. 11)

Pricing for amorphous steel has increased slightly since the preliminary analysis but less so than GOES steel, and in particular foreign produced GOES. As such, amorphous steel is generally more competitive on first cost than it was in the preliminary analysis. As NEEA suggested, DOE did observe instances where amorphous transformers are lower first cost. However, that has not necessarily led to increased adoption, in part because most manufacturers' capital equipment is set-up for GOES core production. Amorphous transformer production would require manufacturer investment to fill high volume orders. As such, the first cost competitiveness of amorphous steel in certain applications has not necessarily corresponded to equivalent market share. DOE has continued to assume sourced core pricing for amorphous steel as most manufacturers do not have the capacity to produce cores in volume. While Metglas notes that manufacturers producing their own cores could have lesser costs, DOE notes in that scenario they would likely have additional retooling costs that would be aggregated over unit volume and increase core price relative to raw materials. More details regarding DOE's pricing of amorphous steel are included in chapter 5 of the TSD.

For this NOPR, DOE's analysis shows that it is cost-effective to meet the proposed standards for liquid-immersed and low-voltage dry-type distribution transformers fabricated with amorphous steel cores. An energy conservation standard that significantly increases adoption of amorphous core distribution transformers would represent a substantial shift in the distribution transformer market. Such a shift could impact pricing and competition among steel suppliers in ways that may not be perfectly predictable, as the resulting market equilibrium would depend on decisions made by market participants outside of DOE's control. However, it is important to emphasize that price volatility in electrical steel and shifts in the market's competitive balance are not limited to amorphous steel.

Substantial volatility has characterized the U.S. 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.[51] In 2010, the price of steel began to recover. However, the recovery was driven more by increasing cost 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.[52] 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 2010's.

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 Commission.[53] The resulting investigation found that "an industry in the United States is neither materially injured nor threatened with material injury by reason of imports of grain-oriented electrical steel . . . to be sold in the United States at less than fair value." [54]

In the amorphous steel market, the necessary manufacturing technology has existed for many decades and has been used in distribution transformers since the late 1980s.[55] In many countries, amorphous steel is widely used in the cores of distribution transformers.[56] Significant amorphous steel use tends to occur (1) in places with both comparatively lower labor costs and significant electrification (*e.g.,* India, China); and (2) in regions with relatively high loss valuations on losses (*e.g.,* certain provinces of Canada).

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.*[57] 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.*[58] Given the recency of several publications, combined with the supply chain disruptions caused by the Covid–19 pandemic, many of the price effects that, directly or indirectly, impact the pricing of distribution transformers may still be stabilizing.

Another recent trend in distribution transformer manufacturing is an increase in 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 if the steel is imported, 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 unfairly traded.[59] [60] 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.[61] [62]

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 their investigation, DOC stated it is exploring several options to shift the market towards domestic production and

[51] International Trade Administration. *Global Steel Report.* (Last accessed September 1, 2022) *https://legacy.trade.gov/steel/pdfs/global-monitor-report-2018.pdf.*

[52] 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.

[53] U.S. International Trade Commission, *Grain-Oriented Electrical Steel from Germany, Japan, and Poland,* Investigation Nos. 731–TA–1233, 1234, and 1236. September 2014.

[54] *Id.*

[55] DeCristofaro, N., *Amorphous Metals in Electric-Power Distribution Applications,* Material Research Society, MRS Bulletin, Volume 23, Number 5, 1998.

[56] BPA's Emerging Technologies Initiative, *Phase 1 report: High Efficiency Distribution Transformer Technology Assessment,* April 2020. Available online at: *https://www.bpa.gov/EE/NewsEvents/presentations/Documents/Transformer%20webinar%204-7-20%20Final.pdf.*

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

[58] Congressional Research Service, *Section 232 Investigations: Overview and Issues for Congress,* May 18, 2021, Available online at: *https://fas.org/sgp/crs/misc/R45249.pdf.*

[59] (AK Steel, Docket No. BIS–2020–0015–0075 at pp. 43–58).

[60] (American Iron and Steel Institute, Docket No. BIS–2020–0015–0033 at pp. 2–5).

[61] (Central Maloney Inc., Docket No. BIS–2020–0015–0015 at pp. 1).

[62] (NEMA, Docket No. BIS–2020–0015–0034 at pp. 3–4).

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 NOPR. 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, it is similar between domestic and foreign electrical steel (*i.e.,* the price of foreign electrical steel without any tariffs applied). (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 (NOES) 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)

Since 2016, there has been one domestic supplier and multiple global suppliers of GOES. The amorphous steel market follows the same pattern, with one domestic supplier and multiple global suppliers. Further, although the current foreign suppliers of amorphous steel are primarily based in Japan and China, DOE received feedback through public comment and manufacturer interviews that South Korean and German steel suppliers have the capabilities to expand their steel production to include amorphous steel, if demand for amorphous steel increases. (Metglas, No. 11 at p. 2) DOE does not have data suggesting that amorphous steel is inherently more expensive to produce than GOES. Both varieties rely on similar inputs and both are capital-intensive, therefore tending to reduce per-pound production costs with higher capacity utilizations.

Public comments by Metglas stated that within two years of developing the know-how to produce amorphous ribbon, producers in China were able to add 70,000 Mt of capacity.[63] Public statements from one manufacturer in Europe note that since the expiration of an initial patent related to amorphous steel production, there have been a number of additional amorphous suppliers and material prices have been stable.[64] Given these historical examples with which manufacturers have been able to quickly add amorphous capacity, along with the cited number of producers capable of making amorphous steel, DOE's view is that it is reasonable to expect that if there were insufficient amorphous steel production capacity to meet amended energy conservation standards, some manufacturers with the expertise to produce amorphous steel would enter the market and manufacturers currently without the expertise to manufacture amorphous steel may invest in its development.

Additionally, during manufacturer interviews, stakeholders indicated that in the current marketplace there are shortages of GOES steel products, leading to greater price levels and volatility. Because GOES production can be shifted to NOES products at modest cost, these shortages are likely driven at least in part by rising demands for NOES in manufacture of motors and electric vehicles. This demand creates competition for GOES production capacity. Given recent trends of decarbonization initiatives and industrial reshoring, the manufacture of NOES for electric vehicle production appears poised to put competitive pressure on GOES production well into the future.[65]

Further, there has been, and remains, competition for available low-loss grades of GOES between the power and distribution transformer segments. Cliffs commented that while high-permeability GOES works well in distribution transformers, it has historically been sold as a laser DR product to the power transformer market; NEMA commented that both distribution and power transformers compete for steel demand. (Cliffs, No. 57 at p. 1; NEMA, No. 50 at p. 9) Therefore, it is likely that any energy savings associated with use of lower-loss core steel, whether it be amorphous or grain-oriented, would require investment from steel manufacturing industry at-large to increase capacity of either lower-loss GOES steels or of amorphous steel.

Rather than constructing sensitivity analysis scenarios to reflect every potential combination of factors that may affect steel pricing (*e.g.,* various tariffs and quotas, competition from NOES, decisions by steelmakers in various countries to add production capacity) or making assumptions regarding how changes in production volume affect material prices, DOE relies on a 5-year average pricing for its core steel.

DOE requests comment on the current and future market pressures influencing the price of GOES. Specifically, DOE is interested in the barriers to and costs associated with converting a factory production line from GOES to NOES.

DOE further requests comment regarding how the prices of both GOES and amorphous are expected to change in the immediate and distant future.

DOE requests comment regarding the barriers to converting current M3 or 23hib90 electrical steel production to lower-loss GOES core steels.

DOE requests comment as to if there are markets for amorphous ribbon, similar to NOES competition from GOES production, which would put competitive pressures on the production of amorphous ribbon for distribution transformers.

DOE requests comment on how a potentially limited supply of transformer core steel, both of amorphous and GOES, may affect core steel price and availability. DOE seeks comment on any factors which uniquely affect specific steel grades (*e.g.,* amorphous, M-grades, hib, dr, pdr). Additionally, DOE seeks comment on how it should model a potentially concentrated domestic steel market in its analysis, resulting from a limited number of suppliers for the amorphous market or from competition with NOES for the GOES market, including any use of game theoretic modeling as appropriate.

b. Scrap Factor

In the August 2021 Preliminary Analysis TSD, DOE noted that it applies various scrap markups to distribution transformer bills of materials (August 2021 Preliminary Analysis TSD at p. 2–53). DOE requested comment on its scrap factor markups. Metglas commented that DOE should not apply a scrap to a finished core because the scrap would be included in the core costs. (Metglas, No. 53 at p. 5)

DOE notes that a scrap factor is still applied to prefabricated cores to account for any potential breakage of cores and any scrap associated with assembling the windings or insulation on the cores. However, a lesser factor is used as compared to GOES because much of the scrap costs would be priced into the core production.

Metglas commented that the scrap rate for GOES seemed low but did not provide an alternative value. (Metglas, No. 53 at p. 5) Eaton commented that it is unclear which mark-ups are applied

[63] Metglas, *Section 232 National Security Investigation of Imports of Steel: Comments by Metglas, Inc. Requesting the Inclusion of Amorphous Steel,* 2017. *https://www.bis.doc.gov/index.php/232-steel-public-comments/1835-metglas-amorphous-public-comment.*

[64] Wilson Power Solutions, *Amorphous Metal Transformers—Myth Buster,* 2018. *https://www.wilsonpowersolutions.co.uk/app/uploads/2017/05/WPS_AMT_Myth_Buster_2018-2.pdf.*

[65] Example: California's electric vehicle adoption executive order: *https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf,* 2022.

to which cores and DOE should clarify. (Eaton, No. 55 at p. 14)

DOE has maintained the scrap factors from the preliminary analysis as it did not receive alternative values and has updated the language in chapter 5 of the TSD to better explain how scrap factors were applied. DOE has added equations in chapter 5 to walk through how the material costs were translated to MSPs.

c. Other Material Costs

In the August 2021 Preliminary Analysis TSD, DOE presented material prices and requested comment on a variety of additional materials used in distribution transformer construction. (August 2021 Preliminary Analysis TSD at p. 2–50)

Eaton commented that while windings combs and epoxy resin have materials cost listed, they are not used in liquid immersed transformers. (Eaton, No. 55 at p. 14) DOE notes that it did not apply either of those costs to liquid-immersed distribution transformers and has made that more clear in the NOPR TSD.

Eaton commented that mineral oil and mild steel prices are higher than was shown in the August 2021 Preliminary Analysis TSD. (Eaton, No. 55 at p. 14) Eaton commented that DOE may be underestimating pricing, in part due to underestimating the number and costs of some of the fixed components, such as the number of bushings for RU4 and RU5. (Eaton, No. 55 at pp. 14–16) DOE has made modifications to the pricing of its fixed components and updated costs to reflect generally price changes in the underlying commodities. DOE notes that the fixed-costs generally do not vary with efficiency and as such, higher pricing of these fixed-components would not impact the pay-back periods for more efficient distribution transformers.

Specifically, regarding the cost of the distribution transformer tank, Eaton commented that the cost is too low and appears to have omitted the cost of the cabinet and associated labor. (Eaton, No. 55 at p. 15)

Part of the difference in tank costs cited by Eaton, is likely associated with the increase in tank steel that has occurred between when the preliminary analysis prices were gathered compared to the NOPR prices. DOE has updated tank steel prices, which has increased the price of the distribution transformer tank. DOE notes that weld time would generally be included in calculation of labor. DOE has added additional detail as to calculation of tank cost in chapter 5 of the TSD.

NEMA commented that radiators are not always included in footprint calculations but cabinet/enclosures are and DOE should add these into the analysis. (NEMA, No. 50 at p. 14)

DOE has modeled a cabinet and enclosure in its sizing of distribution transformer tanks. DOE has presented these additional details in chapter 5 of the TSD.

d. Cost Mark-Ups

Factory Overhead

In the August 2021 Preliminary Analysis TSD, DOE noted that it used a factory overhead markup to account for all indirect costs associated with production, indirect materials and energy used, taxes, and insurance. (August 2021 Preliminary Analysis TSD at p. 2–57)

Eaton commented that it was unclear what exactly the factory overhead markup was applied to, for example, did it include only materials the consumer produced themselves or did it apply to purchased parts as well. (Eaton, No. 55 at p. 15)

DOE applied the factory overhead markup to all material costs, which would include purchased parts. DOE understands that purchased parts would still require factory space, certain equipment usage, taxes, and insurance. DOE has added detail in chapter 5 of the TSD as to how it applied the Factory Overhead Mark-up.

Labor

Labor costs are an important aspect of the cost of manufacturing a distribution transformer. In the August 2021 Preliminary Analysis TSD, DOE described how the number of labor hours were derived for each distribution transformer design. For liquid-immersed distribution transformers, DOE generally relied on a bottoms-up approach, estimating the various hours associated with the various steps in distribution transformer manufacturing. For dry-type distribution transformers, DOE relies on a top-down approach to estimate the total labor for a unit using equations derived from manufacturer data. These equations include a base labor charge for a given unit and a variable charge that varies with transformer size. DOE notes in the August 2021 Preliminary Analysis TSD, it mistakenly outlined a bottom-up approach for LVDTs when in fact a top-down labor estimate was used. This discussion is modified in chapter 5 of the TSD, while the estimated labor per unit is unchanged.

In response to the August 2021 Preliminary Analysis TSD, Eaton noted that the estimates of labor hours for RU4 and RU5 appeared to notably underestimate the required labor per unit and noted many specific areas in the bottom-up approach that appeared to underestimate labor. (Eaton, No. 55 at p. 17–19) Eaton also noted that DOE overestimated the RU5 additional number of labor hours for building an amorphous distribution transformer and that the only difference would be that an amorphous transformer would have a split core assembly, which would require above 1 hour of additional labor. (Eaton, No. 55 at p. 20)

In manufacturer interviews, DOE received concurring feedback that while its estimates of labor per unit and bottoms-up approach were approximately accurate for its single-phase, liquid-immersed units, three-phase units require substantially more labor. DOE relied on manufacturer interviews and confidential data to develop estimates for labor hours for RU4 and RU5 that assumes a base labor number of hours and a variable that scales with unit size, similar to what is done for the dry-type distribution transformers. These equations are presented in chapter 5 of the TSD.

Eaton commented that it believes the fully burdened cost of labor is way too low and a value of $200/hour or more seems more appropriate. (Eaton, No. 55 at p. 16)

DOE applies a labor cost per hour that is generally derived from the U.S. Bureau of Labor Statistic rates for North American Industry Classification System (''NAICS'') Code 335311—''Power, Distribution, and Specialty Transformer Manufacturing'' production employee hourly rates and applied mark-ups for indirect production, overhead, fringe, assembly labor up-time, and a nonproduction mark-up to get a fully burdened cost of labor. In the preliminary analysis, DOE adjusted the labor rate upward in response to manufacturer feedback. While some manufacturers may have different labor costs, DOE generally considers the BLS statistics approximately representative. DOE has adjusted labor costs from the preliminary analysis based on the ratio of increased labor costs in NAICS code.

Shipping

In the August 2021 Preliminary Analysis TSD, DOE noted that it used a price per pound estimate to estimate the shipping cost of distribution transformers. DOE stated that while shipping costs will vary depending on several factors, including weight, volume, footprint, order size, destination, distance, and other, general shipping costs (fuel prices, driver wages, demand, etc.), the price-per-pound estimate is an appropriate approximation of shipping costs and reflects that there would be increased shipping costs associated with larger distribution transformers. DOE then applied a non-production markup on top of its shipping costs. DOE requested comment on its methodology and the shipping costs used in the preliminary analysis. (August 2021 Preliminary Analysis TSD at p. 2–56)

Howard commented that they have their own shipping division and trucks and optimize shipments to be most efficient. (Howard, No. 59 at p. 3) Eaton commented that shipping costs vary but on average, DOE's shipping cost estimates are reasonable. (Eaton, No. 55 at p. 16)

DOE did not receive any comment or data suggesting an alternative approach to shipping costs, therefore DOE has retained its price-per-pound mark-up to account for shipping in the NOPR analysis.

Manufacturer Markup

To account for the manufacturer's nonproduction costs and profit margin, DOE applies a manufacturer markup to the MPC. The resulting MSP is the price at which the manufacturer distributes a unit into commerce. In the preliminary analysis, DOE applied a gross margin percentage of 20 percent for all distribution transformers.[66]

Eaton commented that its gross profit margin was higher and a 20 percent gross margin is too low for a publicly traded corporation with obligations to stakeholders.[67] (Eaton, No. 55 at p. 16–17)

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 whose combined product range includes distribution transformers.

While some corporations may have higher gross 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. While some manufacturers noted higher or lower gross margins, depending on the product class, there was generally agreement that the 20 percent gross margin was appropriate for the industry. As such, DOE has retained the 20 percent gross margin as part of the NOPR analysis.

4. Cost-Efficiency Results

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

Powersmiths commented that the cost-efficiency plots show it is too cheap to achieve higher efficiency and if it were really that cheap, the market would move there without legislation. (Powersmiths, No. 46 at p. 5) Conversely, Metglas commented that the market does not evaluate based on efficiency and the only way to see efficiency improvements is via amended energy conservation standards. (Metglas, No. 53 at p. 8)

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.c). Therefore, DOE does not have data to support manufacturers will build above minimum efficiency standards, aside from certain select applications, even if it were only modestly more expensive.

The Efficiency Advocates commented that the percentage of transformers core steels purchased in the preliminary analysis shows that too few GOES transformers are being selected, indicating a potential issue in the engineering analysis. (Efficiency Advocates, No. 52 at p. 7)

DOE has acknowledged that aside from lowest first cost, manufacturers may be limited in their steel choice under the base case. In certain cases, the incremental cost to higher efficiency standards may be low but assumes access to suppliers of better performing steel. DOE has updated its baseline analysis to reflect the steel choices that are currently made in the industry as described in section IV.F.3.a.

D. Markups Analysis

The markups analysis develops appropriate markups (*e.g.,* retailer markups, distributor markups, contractor markups) in the distribution chain and sales taxes to convert the MSP estimates derived in the engineering analysis to consumer prices, which are then used in the LCC and PBP analysis. 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.

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

Liquid-immersed distribution transformers are almost exclusively purchased and installed by electrical distribution companies, as such the distribution chained assumed by DOE reflect the different parties involved. 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 modelled that dry-type distribution transformers are purchased by non-residential customers, *i.e.,* commercial, and industrial customers.

DOE considered the following distribution channel shown in Table IV.5.

TABLE IV.5—DISTRIBUTION CHANNELS FOR DISTRIBUTION TRANSFORMERS

Type	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.

[66] The gross margin percentage of 20 percent is based on a manufacturer markup of 1.25.

[67] A 20 percent gross margin is equivalent to a 1.25 manufacturer markup.

TABLE IV.5—DISTRIBUTION CHANNELS FOR DISTRIBUTION TRANSFORMERS—Continued

Type	Consumer	Market share (%)	Distribution channel
MVDT	All	100	Manufacturer → Distributor → Electrical contractor→ Consumer.

Howard commented that in in their experience that liquid-immersed distribution transformers are sold directly (more than 80%) to the utilities through our agents or manufacturing representatives. (Howard, No. 59 at p. 2) DOE notes that the distribution channels used in the preliminary analysis include a large fraction of sales as being direct to purchases by utilities that would encompass the circumstances described by Howard, as shown in Table IV.5.[68] For this analysis DOE maintained the distribution channels distribution channels described in its preliminary analysis.

Chapter 6 of the NOPR 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.C transformers 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 at when the transformer is unloaded, but grow quadratically with load on the transformer.

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

1. 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 Life-cycle Cost (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 types 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 the data made available through the IEEE Distribution Transformer Subcommittee Task Force.

a. Hourly Per-Unit Load (PUL)

GEUS commented that because of load diversity, individual distribution transformer capacity (kVA) per home depends on the number of homes connected to the transformer. For example, GEUS will place a 15 kVA transformer for a single 1200 square foot home, but 8 of these homes can be served by a single 50 kVA transformer. GEUS further commented that to balance transformer core (no-load) losses and resistive (load) losses their design strategy is to serve as many homes as possible within a 300 feet radius of the transformer. This design reduces transformer core (no-load) losses by reducing the transformer kVA/home, thereby reducing the ratio of no-load to load losses on each transformer. (GEUS, No. 58 at p. 1) Howard commented that it is their understanding that in some rural areas, there are transformers that are very lightly loaded, and in other areas, some units are loaded much more than 50 percent (Howard, No. 59 at p. 3) NEMA commented that the in-situ PUL varies widely from region to region and customer to customer. (NEMA, No. 50 at p. 12)

The Advocates asserted that DOE's estimation of PUL to be too high and that if DOE decides to maintain these PUL inputs at their current values, the Department should provide a sensitivity analysis that enables commenters to evaluate the effect of PUL assumptions on the overall energy savings and economic analysis. (Efficiency Advocates, No. 52 at p. 6) Additionally, they commented that they believe DOE may be overestimating initial PUL (*sic*) in the preliminary analysis; this may negatively affect higher EL designs that prioritize core loss reductions and they urged DOE to update its assumptions based on recently available data. (Efficiency Advocates, No. 52 at pp. 2, 5)

Metglas commented that it is not possible to derive transformer PUL just from the meter data. To get a transformer's PUL, one must associate which meters are getting supplied from which transformer. Further Metglas commented that, the data has come from only 127 zip codes adjacent to each other. Metglas asserted that the sample is too small to draw conclusions at the National level, and suggested that DOE base their ruling on data submitted by Electric Utilities to the IEEE Transformer Committee which indicates

[68] See: Technical Support Document, chapter 2, page 2–58. *https://www.regulations.gov/document/EERE-2019-BT-STD-0018-0040.*

that the average PUL on transformers are in the 0.1–0.2 values. (Metglas, No. 53 at p. 7–8)

NEEA further noted that the per-unit bases for both the system and individual transformer loads in the joint histogram estimates are not related to the transformer per-unit loads using nameplate capacities as the basis. They claim that this means that the loading estimates obtained from the joint histograms cannot be directly applied to the cited transformer loss formula, since the latter assumes a per-unit loading on a capacity basis. (NEEA, No. 51 at p. 2–3)

In this NOPR, DOE applied the same approach it used in the August 2021 preliminary analysis where the hourly PUL is a function of both the transformer's simulated load and initial peak load (*IPL*). Where:

$PUL = simulated\ load_{hourly} \times IPL.$

To capture the wide diversity in distribution transformer loading that is observed in the field, 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.[69] 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 U.S., DOE used FERC Form 714[70] 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 (*IPL*), 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.

In response to the comments from the Advocates and Metglas, DOE revised the *IPL* assumptions in this NOPR to more closely align the resulting *PUL* with data made available through the IEEE Distribution Transformer Subcommittee Task Force. The revised mean PULs for liquid-immersed representative unit used in this NOPR are shown in Table IV.6.

TABLE IV.6—DISTRIBUTION OF PER-UNIT-LOAD FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Rep. unit	Mean simulated hourly load	Mean IPL	Mean PUL
1	0.29	0.75	0.22
2	0.27	0.75	0.20
3	0.32	0.75	0.24
4	0.26	0.75	0.20
5	0.31	0.75	0.23

b. Joint Probability Distribution Function (JPDF)

NEEA commented that when processing the load data into JPDF of loads that observed hourly loads for both commercial and residential customers were scaled by corresponding annual maxima prior to being counted towards the joint histogram, so that the observations may be treated as if on a per-unit basis. This is inconsistent with the per-unit notion in power systems, but permissible in this context if so stated. However, the problem of bias applied to an entire set of observations for a given transformer or ''system'' by an abnormally large (or small) peak observation is not acknowledged and therefore not treated. (NEEA, No. 51 at p. 2). DOE notes that the transformer data were screened to remove outliers before being used to construct JPDFs; a small number of transformers in the database may none-the-less have quite large or quite small peak loads, but the associated low probability leads to minimal impact on the energy loss calculations. The data will be reviewed again to ensure that outliers have been removed.

NEEA found issue with DOE's terminology in the TSD, which stated that DOE applies the joint histogram as a measure of correlation; and this is not the typical interpretation of joint probability. NEEA further recommended that a covariance-based measure (*e.g.,* correlation coefficient) is the appropriate class of metric in this case because the subject load processes will necessarily be related as a consequence of common influences, each of which is in turn a stochastic process. (NEEA, No. 51 at pp. 2–3) In response, DOE agrees with NEEA's comment that the term ''correlation'' used in the TSD is not appropriate. The system load is the sum of the loads on individual transformers, so the system load and transformer loads are not independent random variables. The relationship between the two, represented by the JPDF, is a conditional probability distribution. DOE attempts to document its analyses in plain language, and the term correlation was used simply to indicate that the relationship between the transformer and system loads is not random. For this NOPR DOE will continue to use the term correlation to describe the general relationship between transformer and system loads, using footnotes to provide technical precision as needed.

On the topic of industrial loads for liquid-immersed distribution transformers NEEA asserted that as describe in the TSD appendix 7A, that in the case of industrial customers, actual transformer load data were not available and would be problematic for the estimation of the subject joint histograms. (NEEA, No. 18 at p. 2) At the time of the August 2021 Preliminary Analysis TSD, DOE was unable to acquire the transformer loads from industrial customers. As discussed in

[69] See: Distribution Transformer Load Simulation Inputs, Technical Support Document, chapter 7.

[70] *https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.*

TSD appendix 7A, DOE was able to include the hourly meter loads from industrial customers, which contain hourly variability in load factor, as proxies for transformer loads—which were included in its database of JPDFs.

DOE requests comment or data showing hourly transformer loads for industrial customers.

NEEA additionally requested that DOE rationalize the choice of bin resolution in the joint histogram estimates. (NEEA, No. 51 at p. 2) In the August 2021 Preliminary Analysis TSD, DOE applied the same methodology to the creation and population of JPDFs as it did in the April 2013 Standards Final Rule. For the April 2013 Standards Final Rule, DOE balanced the bin resolution to 10 bins to ensure that each bin contained sufficient data to be sampled during its Monte Carlo simulation (~2 percent of samples per bin), this was also balanced against the computational limits of preforming this model within an Excel spreadsheet. For the August 2021 Preliminary Analysis TSD, DOE considered increasing the bin count, but after testing found that this did not significantly alter the resulting averages, as such DOE elected to maintain the approach that stakeholders were already familiar with. For this NOPR, DOE will maintain the 10 bins that were applied in the August 2021 Preliminary Analysis TSD.

2. Monthly Per-Unit Load (PUL)

Powersmiths commented that, in the context of low-voltage dry-type distribution transformers, it has consistently measured much lower typical loading levels, across most vertical markets, in the range of 15–25 percent of nameplate capacity, which is in line with the publication in 1999 with the Cadmus Group Study and supported frequently since then in industry and at previous rulemaking sessions. (Powersmiths, No. 46 at p. 1)

DOE received no further comments on the in-field PUL for dry-type distribution transformers. Since the comments from Powersmiths align with DOE's analysis which shows an average RMS PUL for dry-type transformers to be in 16–27 percent of nameplate capacity DOE did not make any changes to its dry-type load model for this NOPR.

3. Future Load Growth

In its August 2021 Preliminary Analysis TSD, DOE applied an annual load growth rate of 0.9 percent, based on *U.S. Energy Information Administration (*''*EIA*''*), Annual Energy Outlook* (''AEO'') 2021 projected purchased electricity: delivered electricity trend, to liquid-immersed transformers, and zero percent for low- and medium-voltage dry-type transformers.[71] On the subject of future load growth DOE received comments from EEI, CDA, Howard, Efficiency Advocates, Metglas. and NEMA.

Both EEI and CDA commented that they believe that loads on individual liquid-immersed distribution transformers will increase over the equipment's lifetimes due to several factors. Both speculated that the increase in loads will be driven by evolving ''mega trends'' in the electric utility industry, specifically increased electric vehicle charging, and increased building electrification. (EEI No. 56 at p. 2; CDA No. 47 at p. 1) The CDA further commented that EEI has projected loading increases of 10–50 percent over the forecast period that will greatly change operating practices in the utilities. This suggests the increasing importance of transformer load losses as well as balance and minimization of total losses. (CDA, No. 47 at p. 2) Howard commented that we are at the threshold of having many electric vehicles (EV) that will require a lot of energy use through the transformer. How quickly this will happen, remains to be seen. (Howard, No. 59 at p. 3)

NEMA commented that while they could not state with certainty what the appropriate load growth rate would be, they disagreed with an assumption of zero percent load growth. (NEMA, No. 50 at p. 13)

The Advocates, and Metglas challenged DOE application of a 0.9 percent annual load growth for liquid-immersed distribution transformers. Both asserted that the assumption of load growth rate applied to liquid-immersed distribution transformers of 0.9 percent per year was not justified as the National growth in electric demand will be matched by increased distribution capacity. They asserted that the load growth rate assumed by DOE, the average increase in annual electricity sales from *AEO,* is not entirely driven by increased electrical load on existing liquid-immersed distribution transformers, but in fact driven by grid expansion. (Advocates, No. 52 at pp. 5–6; Metglas, No. 53 at pp. 1, 5–6)

Additionally, the Advocates commented that they believe utilities will plan conservatively by installing larger transformers capable of handling rare peak demand events. Citing as evidence the IEEE load data as suggesting utilities are already doing this as the reported average peak loads were only 50 percent of nameplate capacity. Utility decisions for how they size transformers are unlikely to change for new and replacement transformer installations given the uncertainties around future electricity demand. (Efficiency Advocates, No. 52 at pp. 5–6) This notion was supported by NEMA who commented that as consumer demand (for electricity) increases due to the migration to all-electric homes and buildings, and it stands to reason that kVA sizes will increase over time as utilities upgrade capacity to serve these consumer demands. Likewise, investments in renewable energy generation will cause changes to transformer shipments, unit sizes and selections. (NEMA, No. 50 at p. 16)

As the August 2021 Preliminary Analysis TSD indicated, and by the comments received, there are many factors that potentially impact future distribution transformer load growth, and that these factors may be in opposition. At this time, many utilities, states, and municipalities are pursuing electric vehicle charging programs, it is unclear the extent to which increases in electricity demand for electric vehicle charging, or other state level 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). EEI, CDA, and Howard speculate that these initiatives will increase the intensive per-unit-load over time as a function of per unit of installed capacity. However, they did not provide any quantitative evidence that this is indeed happening on the distribution systems, or regions which are moving forward with decarbonization efforts. Further, the hypothesis that intensive load growth will be a factor in the future is not supported by the available future trends in *AEO2022,* as indicated by the purchased electricity trend as it represents the delivered electricity to the customer. The Advocates and Metglas asserted that the load growth rate 0.9 percent per year was too great, and 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

[71] TSD chapter 2, p. 2–63, August 2021. *https://www.regulations.gov/document/EERE-2019-BT-STD-0018-0040.*

through larger distribution transformers, or greater shipments, or some combination of both. Again, neither the Advocates nor Metglas provided any data to support their position. For this NOPR, DOE finds that neither position provides enough evidence to change its assumptions from the August 2021 Preliminary Analysis TSD. For this NOPR, DOE updated its load growth assumption for liquid-immersed distribution transformers based on the change in average growth of *AEO2022:* Purchased Electricity: Delivered Electricity at 0.5 percent.[72]

To help inform DOE's prediction of future load growth trend, DOE seeks data on the following for regions where decarbonization efforts are ongoing. DOE seeks hourly PUL data at the level of the transformer bank for each of the past five years to establish an unambiguous relationship between transformer loads and decarbonization policy and inform if any intensive load growth is indeed occurring. Additionally, DOE seeks the average capacity of shipment into regions where decarbonization efforts are occurring over the same five-year period to inform the rate of any extensive load growth that may be occurring in response to these programs.

4. Harmonic Content/Non-Linear Loads

Harmonic current refers to electrical power at alternating current frequencies greater than the fundamental frequency. Distribution transformers in service are commonly subject to (and must tolerate) harmonic current of a degree that varies by application.

Powersmiths commented that the effects of harmonic content on LVDT can create significant customer risk due to transformer overheating, particularly when the transformer is under heavy loads. This was primarily an issue when general purpose transformers are installed outside prescribed harmonic limits. (Powersmiths No. 18 at p. 3)

Additionally, Powersmiths asserted that because DOE does not account for harmonic content in its loading analysis that it misrepresents the impact of additional heat on losses. Powersmiths concluded that light loading means the harmonic-related heat does not typically threaten the transformer, but it is not an excuse to leave this hidden risk unsaid as the load on any given transformer could be taken to full capacity based on its nameplate rating, and associated protection, at any time during its long life. (Powersmiths No. 18 at p. 3) NEEA requested that for the next energy conservation lookback that DOE include harmonic content in its analysis (NEEA No. 18 at p. 4)

In response to the commenters regarding the inclusion of harmonic content, DOE agrees with NEEA and that in addition to determining the necessary input to adequately model the impacts of harmonic content at the National level, DOE would also have to consider how changes in transformer design would affect the availability of designs and the impacts on efficiency. DOE further concurs with Powersmiths that, on average, distribution transformers are lightly loaded, as shown in its analysis (see section IV.E.2) and that harmonic heat would not typically be an issue and would likely have minimal impact on the transformers covered by this NOPR. For this NOPR DOE will not consider the impacts of harmonic content but may examine them at a future date.

DOE notes that the installation and commissioning of distribution transformers, either general purpose or specialty equipment, falls outside the Department's authority and would be under the purview of local building or fire codes and ordinances.

Chapter 7 of the NOPR 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 of potential energy conservation standards for distribution transformers. The effect of new or 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 (''C&I'') customers. As stated previously, DOE developed these customers samples from various sources, including utility data from the Federal Energy Regulatory Commission (FERC), Energy Information Agency (EIA); and C&I 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 the 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 transformer.

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. 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

[72] *www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2022&region=1-0&cases=ref2022&start=2020&end=2050&f=A&linechart=ref2022-d011222a.152-2-AEO2022.1-0~ref2022-d011222a.104-2-AEO2022.1-0&map=ref2022-d011222a.4-2-AEO2022.1-0&ctype=linechart&sourcekey=0.*

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.3 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 already purchase more-efficient products, 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 a new equipment in the expected year of required compliance with new or amended standards. Amended standards would apply to distribution transformers manufactured 3 years after the date on which any new or amended standard is published. At this time, DOE estimates publication of a final rule in 2024. Therefore, for purposes of its analysis, DOE used 2027 as the first year of compliance with any amended standards for distribution transformers.

Table IV.7 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 NOPR TSD and its appendices.

TABLE IV.7—SUMMARY OF INPUTS AND METHODS FOR THE LCC AND PBP ANALYSIS *

Inputs	Source/method
Equipment Cost	Derived by multiplying MPCs by manufacturer and retailer markups and sales tax, as appropriate. Used historical data to derive a price scaling index to project product costs.
Installation Costs	Assumed no change with efficiency level.
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 2021 using *AEO2022.* *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 2021 using *AEO2022.* *Variability:* Regional variability is captured through individual price signals for each Census region.
Energy Price Trends	Based on *AEO2022* 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	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.
Compliance Date	2027.

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

To forecast a price trend for this NOPR, DOE maintained the approach employed in the August 2021 Preliminary Analysis TSD, where it derived an inflation-adjusted index of the Producer Price Index (''PPI'') for electric power and specialty transformer manufacturing from 1967 to 2019.[73] These data show a long-term decline from 1975 to 2003, and then increase since then. There is considerable uncertainty as to whether the recent trend has peaked, and would be followed by a return to the previous long-term declining trend, or whether the recent trend represents the beginning of a long-term rising trend due to global demand for distribution transformers and rising commodity costs for key distribution transformer components. Given the uncertainty, DOE chose to use constant prices (2021 levels) for both its LCC and PBP analysis and the NIA. For the NIA, DOE also analyzed the sensitivity of results to alternative distribution transformer price forecasts.

DOE did not receive any comments regarding its determination of future equipment costs and did not make any changes for this NOPR.

2. Efficiency Levels

For this NOPR, DOE analyzed different efficiency levels, these are expressed as a function of loss reduction over the equipment baseline. For units greater than 2,500 kVA, there is not a current baseline efficiency level that must be met. Therefore, DOE established EL1 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 2,500 kVA unit to the 3,750 kVA size using the equipment class specific scaling relationships in TSD appendix 5C. For example, a 2,500 kVA unit that meets current energy conservation standards is 99.53 percent efficient and has 5903 W of loss at 50 percent load. Using the 0.79 scaling relationship for three-phase liquid-immersed distribution transformers, described in appendix 5C, the losses of a 3,750 kVA unit would be 8131 W, corresponding to 99.57 percent efficient at 50 percent load.

EL2 through EL5 align with the same percentage reduction in loss as their respective EC but rather than being relative to a baseline level, efficiency levels were established relative to EL1 levels.

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

The rate of reduction is shown in Table IV.8, and the corresponding efficiency ratings in Table IV.9.

TABLE IV.8—EFFICIENCY LEVELS AS PERCENTAGE REDUCTION OF BASELINE LOSSES

Equipment type	EL				
	1	2	3	4	5 (max-tech)
Liquid-immersed:					
≤2,500 kVA	2.5	5	10	20	40
>2,500 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 ≤2,500 kVA	5	10	20	30	40
≥46 and <96 kV BIL, and >2,500 kVA	*43	**10	**20	**30	**40
≥96 kV BIL and ≤2,500 kVA	5	10	20	30	35
≥96 kV BIL and >2,500 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 EL1.

TABLE IV.9—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	1,500	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	1,500	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	1,500	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	2,000	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	1,000	99.43	99.44	99.46	99.49	99.54	99.66
17	3,750	n.a.	99.57	99.59	99.61	99.66	99.74
18	3,750	n.a.	99.48	99.53	99.58	99.64	99.69
19	3,750	n.a.	99.41	99.47	99.53	99.59	99.62

DOE did not receive any comment regarding the loss rates, nor the efficiency levels applied in the preliminary analysis, and continued their use for this NOPR.

DOE requests comments on its methodology for establishing the energy efficiency levels for distribution transformers greater than 2,500 kVA. DOE request comment on its assumed energy efficiency ratings.

3. Modeling Distribution Transformer Purchase Decision

In the August 2021 Preliminary Analysis TSD, DOE presented its assumption on how distribution transformers were purchased. DOE used an approach that focuses on the selection criteria customers are known to use when purchasing distribution transformers. Those criteria include first costs, as well as the Total-Owning Cost (''TOC'') method. The TOC method combines first costs with the cost of losses. Purchasers of distribution transformers, especially in the utility sector, have historically used the TOC method to determine which distribution transformers to purchase. However, comments received from stakeholders responding to the 2012 ECS NOPR (77 FR 7323) and the June 2019 RFI (84 FR 28254) indicate 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.

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.[74] A and B are the

[74] 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 August 2021 Preliminary Analysis TSD, DOE received the following comments regarding the modeling of distribution transformer purchases.

a. Basecase Equipment Selection

Regarding how engineering designs were selected by the consumer choice model in the LCC, DOE received comments from Metglas and the Efficiency Advocates. Metglas commented that it did not agree with the DOE purchase decision model. Stating that the fraction of designs using amorphous steel as a core material were grossly overstated in the standards, and no-new standards cases. Metglas further stated that currently the fraction of amorphous core distribution transformers is on the order of 2–3 percent of the market and that this fraction has been constant for the past 7 years. (Metglas, No. 53 at pp. 1–2) Additionally, the Efficiency Advocates recommended that DOE take ''a hard look at'' the purchasing behaviors of distribution transformers in the current marketplace. (Efficiency Advocates, No. 40 at p. 83)

In response to these comments DOE examined its responses received during manufacturer interviews. From these responses, DOE understands that in the current market that amorphous core distribution transformers (both liquid-immersed and dry-type) are shipped in limited quantities, supporting Metglas' claim. The reason for this is believed to be limitations in amorphous core fabricating capacity among manufacturers. DOE's research indicates 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 requirement of electric utilities, and as such, are limited to niche products. Accordingly, DOE has updated its customer choice model and, in the no-new standards case has limited type of core steel materials to the ratios shown in Table IV.10.

TABLE IV.10—CORE MATERIAL LIMITS IN THE NO-NEW STANDARDS CASE

Baseline Steel for Liquid-Immersed: • 87% M3 or 23hib090. • 3% Amorphous (mostly in TOC applications above standards). • 10% 23PDR085.	*Baseline Steel for Dry-Type:* • 97% M4 or hib-M4 (M3 as modeled). • 3% PDR. • 0% AM.

Based on interviews with manufactures, and supporting research, DOE finds that there are no global supply constraints of amorphous ribbon for fabrication into transformer cores. And in the potential new-standards case, DOE does not limit the selection of the designs in the engineering database by core material type. Further, DOE understands that there are current production limitations for turning amorphous ribbons into transformer cores that would require the capital investment in ribbon cutting, and core stacking machines at higher intensities to meet the quantity requirements placed on manufacturers by electric utilities. The impacts of the additional capital investment on manufacturers in the potential new-standards case are captured in manufacturer impact analysis described in section IV.J of this document.

b. Total Owning Cost (''TOC'') and Evaluators

In the August 2021 Preliminary 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 comment from several stakeholders regarding the rates at which TOC are practiced.

NEMA commented that the experience among their members varies, but in NEMA's experience the percentage of TOC use in purchasing decisions for three-phase designs is higher than 10 percent: varying between 15–20 percent, and for single-phase designs, they believe the use of TOC in purchasing decisions is closer to 40 percent. (NEMA, No. 50 at p. 13) Additionally, NEMA responded to DOE's request for information relating customer application of TOC as a function of distribution transformer capacity. NEMA responded that NEMA did not have detailed information on breakouts of TOC purchasing influence by kVA and that their members are investigating whether their customer information can be analyzed for useful insight on this subject (NEMA, No. 50 at pp. 13–14) Metglas commented that few transformer purchasers are using TOC evaluations, and 10 percent may be a reasonable estimate for those still using TOC. And in their experience the few remaining TOC evaluators reveal that they will abandon TOC as soon as their existing tenders are delivered.; leading to speculation that this practice could be nearly extinct within the next 2–3 years. (Metglas, No. 53 at p. 6)

DOE estimated the rate of consumers using TOC as a tool to inform the purchase of a distribution transformer to be 10 percent for liquid-immersed distribution transformers. These rates were established in response to stakeholder comments in the February 2012 NOPR (77 FR 7323) to which DOE received no adverse comments. Further, these rates were again put forward for comment in the June 2019 RFI (84 FR 28254) to which DOE did not receive any adverse comments.[75] In light of this long history of established low rates of TOC adoption for the purchase of distribution transformers DOE finds the comments received from NEMA to be inconsistent with historical comments from a wide range of stakeholders. *Ibid.* For this NOPR, DOE is maintaining the same rates of TOC evaluators established in the August 2021 ECS Preliminary Analysis TSD, however, DOE recognizes that circumstances change over time and has included in this NOPR a LCC sensitivity case with evaluation rates suggested by NEMA. The result of this sensitivity analysis can be found in appendix 8G of the TSD.

Powersmiths commented that it is not true that 100 percent of LVDT distribution transformers are purchased on minimum first cost, adding that their market is selling only distribution

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.

[75] Please see the summary of comments regarding the rate of evaluators in the August 2021 ECS Preliminary Analysis, Technical Support Document, p 2–69; *https://www.regulations.gov/document/EERE-2019-BT-STD-0018-0023.*

transformers that significantly exceed minimum efficiency standards and the NEMA Premium transformer market existed prior to the 2016 energy conservation standards. (Powersmiths, No. 46 at pp. 3–4) Powersmiths commented that minimum efficiency is rarely the optimal choice for consumers and there is value in both new construction and retrofits that exceed energy conservation standards. (Powersmiths, No. 46 at p. 4) Powersmiths added that trends toward green buildings have increased the number of consumers looking at value beyond first cost which may increase the value-added LVDT market. (Powersmiths, No. 46 at p. 4)

DOE recognizes that distribution transformers are purchased at different efficiency levels depending on the specific demands of consumers. For this analysis DOE did not receive a specific fraction of LVDT distribution transformers that were sold above the current standard, in the absence of such information DOE relied on the consumer choice model to determine the equipment price in addition to the fraction of equipment sold with higher performance cores constructed from PDR steel, as discussed in section IV.F.3.a of this document.

Band of Equivalents (''BOE'')

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 agreed with the Department's assumptions with respect to their reflection of industry experiences and practices. NEMA further stated that its members are investigating whether their customer information can be analyzed for useful insight on this subject. (NEMA, No. 50 at p. 13) Metglas comment that BOE within a TOC calculation is often used because the assumptions within the TOC calculations are estimates. BOE can be up to 10 percent of TOC, meaning the TOC evaluations within this band are treated as equal, and when used in lieu of TOC, the fraction of consumers who evaluate using TOC drops to less than 5 percent. (Metglas, No. 53 at p. 7)

Based on the comments received DOE will maintain the definition previously stated. However, for this NOPR, DOE did not receive enough information or data to apply BOE to a fraction of transformer purchasers.

Evaluation Rates and High Electricity Costs

In the August 2021 ECS Preliminary Analysis TSD, DOE requested comment on whether those consumers that purchase distribution transformers based on TOC are likely to pay higher electricity costs. Howard commented that certain utilities with high electricity costs use the TOC (Total Owning Cost) approach to minimize their overall owning costs. And the manufacturer will work with the user to determine the best overall value to buy, and that this is good approach in those areas. (Howard, No. 59 at p. 3) NEMA commented that it stands to reason that consumers with higher electricity costs are more likely to consider TOC in purchasing decisions. (NEMA, No. 50 at p. 13–14)

The comments DOE received on this subject were supportive of the notion that consumers who have higher electricity costs would reasonably have higher adoption of using TOC as a purchasing tool. However, the comments did not provide any information, or data to support including this relationship in this NOPR. To relate higher electricity costs with increased TOC use, DOE would require from stakeholders the fraction of transformers specified and shipped to regions of higher electricity costs using TOC or BOE.

DOE requests comment on its assumed TOC adoption rate of 10 percent. Specifically, DOE requests comment on the TOC rate suggested by NEMA, that between 15 and 20 percent of 3-phase liquid-immersed distribution transformers are purchased using TOC, and that 40 percent of 1-phase liquid-immersed distribution transformers are purchased using TOC. DOE notes, that it is seeking data related to concluded sales based on lowest TOC in the strictest sense, excluding those transformers sold using band of equivalents (see the section on band of equivalents, above)

DOE requests comment on the fraction of distribution transformers purchased by customers using the BOE methodology. DOE notes, that it is seeking data related to concluded sales based on lowest BOE in the strictest sense, excluding those transformers sold using total owning costs.

DOE request comment if the rates of TOC or BOE vary by transformer capacity or number of phases. Further, DOE seeks the fraction of distribution transformer sales using either method into the different regions in order to capture the believed relationship between higher electricity costs and purchase evaluation behavior.

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. NEMA commented that they disagreed with DOE's assumption that purchasers who do not purchase based on TOC purchase strictly on a first cost basis. Stating, in relation to dry-type distribution transformers, that customers also care about production times, availability, perceived quality, design options and other factors relating to timing and performance. Further, in relation to liquid-immersed transformers, improved tank steel (stainless) or biodegradable immersion oil are potential upgrades outside electrical performance which NEMA members have had requested by customers. (NEMA, No. 50 at pp. 13–14)

DOE acknowledges that customers of distribution transformers will specify design aspects, or other criteria that will impact the cost of a transformer when making a purchasing decision that is not related to distribution transformer efficiency. As mentioned by NEMA in their comment, customers may have additional criteria when purchasing a distribution transformer that would be considered either an equipment upgrade outside of the equipment's electrical performance, or operational considerations that would affect the first costs. The analysis conducted by the Department in support of its energy saving mission are limited to design aspects that affect the quantification of increased energy efficiency of the equipment in question, in this case, distribution transformers. These design aspects are defined in the current test procedure and quantified in the engineering analysis. Since the aspects listed by NEMA are outside of the electrical, and efficiency performance of distribution transformers, therefore they are not considered in this analysis.

4. Installation Costs

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.[76] In the August 2021 Preliminary Analysis 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.

DOE received comments from GEUS, Carte, and NEMA of the subject of installing distribution transformers.

GEUS expressed concern that higher standards may increase transformer weights such that 50 kVA transformers can no longer be handled with standard bucket trucks and would require a larger truck to preform installations. (GEUS, No. 58 at p. 1)

The load bearing capacity of vehicles classified as a bucket truck typically accommodate a wide range of lifting capacity depending on each individual truck. The analysis conducted for this NOPR shows a maximum of weight for a 50 kVA pole mounted liquid-immersed distribution of 1440 lbs. at the maximum technology case. Without knowing the specifics regarding the equipment used by GEUS, DOE cannot definitively say whether their existing bucket trucks will be sufficient.

Transformers are typically installed using a bucket truck, or crane truck. DOE requests comment on the typical maximum lifting capacity, and the typical transformer capacity being installed.

Additionally, Carte and NEMA expressed concern over the increasing of distribution transformer size in order to meet a potential revised standard. Carte commented that utilities are concerned with the increase in size and weight associated with efficiency standards, with potential issues for pole replacement, concrete load limits, and vaults. (Carte, No. 54 at p. 2–3) NEMA commented that when designing a new transformer to fit an existing pad footprint, the only way to add more active material to raise efficiency is to increase the height of the unit. This may not be feasible in situations where cables run underground. There may not be sufficient length remaining in those cables to reach a higher set of bushings to connect the unit to the network. (NEMA, No. 50 at p. 14)

As in the August 2021 Preliminary Analysis TSD, DOE acknowledges that there may be issues when installing a replacement distribution transformer on an existing pad, or underground enclosure. However, as discussed in appendix 7D of the August 2021 Preliminary Analysis TSD, many of these issues can be avoided through proper equipment specification at the time of purchase. The issues that both Carte and NEMA reference, apart from vault replacement/renovation, can be addressed during purchasing with proper specifications. Given that no new information has been put forward in response to the August 2021 Preliminary Analysis TSD, DOE will maintain its assumptions and approach where increased installation costs over the no-new standards case are considered atypical and applied at a rate of 5 percent of installations occurrences.

For this NOPR, DOE reiterates its request for the following information. DOE requests data and feedback on the size limitations of pad-mounted distribution transformers. Specifically, what sizes, voltages, or other features are currently unable to fit on current pads, and the dimension of these pads. DOE seeks data on the typical concrete pad dimensions for 50 and 500 kVA single-; and 500, and 1500 kVA three-phase distribution transformers. DOE seeks data on the typical service lifetimes of supporting concrete pads.

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. Electricity 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 costs model. For low- and medium-voltage dry-type, which are primarily owned and operated by C&I entities, DOE developed a monthly electricity cost model.

a. Hourly Electricity Costs

To evaluate the electricity costs associated with liquid-immersed distribution transformers, DOE used marginal electricity prices. Marginal prices are those utilities pay for the last kilowatt-hour of electricity produced that may be higher or lower than the average price, depending on the relationships among capacity, generation, transmission, and distribution costs. The general structure of the hourly marginal cost methodology divides the costs of electricity into capacity components and energy cost components. For each component, the economic value for both no-load losses and load losses is estimated. The capacity components include generation and transmission capacity; they also include a reserve margin for ensuring system reliability, with factors that account for system losses. Energy cost components include a marginal cost of supply that varies by the hour.

The marginal costs methodology was developed for each regional Balancing Authority listed in EIA's Form EIA–861 database (based on ''Annual Electric Power Industry Report'').[77] To calculate the hourly price of electricity, DOE used the day-ahead market clearing price for regions having wholesale electricity markets, and system lambda values for all other regions. System lambda values, which are roughly equal to the operating cost of the next unit in line for dispatch, are filed by control area operators under FERC Form 714.[78]

EEI commented that the utilization of 2015 data and ''scaling it'' to the year of analysis was misguided given the clean energy progress the electric sector has made in the intervening years. The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly cleaner. EEI commented that, starting in 2016, natural gas surpassed coal as the main source of electricity generation in the United States, and in 2020 natural gas-based generation powered 40 percent of the country's electricity, compared to coal-based generation at 19 percent.

In response to EEI, DOE notes that it scaled the cost of electricity from 2015 to the present using *AEO2022* electricity price trend, and that this trend accounts for changes in the electricity supply mix over this period.[79] Additionally, DOE captures the advances in reducing GHG and other pollutants from the Nation's electricity generators in its Emissions

[76] Gordian, RSMeans Online, *https://www.rsmeans.com/products/online* (Last accessed: March 2022).

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

[78] *https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/overview.*

[79] U.S. Energy Information Administration, Annual Energy Outlook 2022, Table 3. Energy Prices by Sector and Source Case: AEO2022 Reference case | Region: United States, 2022 (Available at: *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2022&region=1-0&cases=ref2022&start=2020&end=2050&f=A&linechart=ref2022-d011222a.3-3-AEO2022.1-0~ref2022-d011222a.55-3-AEO2022.1-0&map=ref2022-d011222a.4-3-AEO2022.1-0&ctype=linechart&sourcekey=0,* Last access: June 1, 2022).

Analysis, described in section IV.K. This analysis captures both shift in generation, and the reduction in coal-based generation, and resulting emissions referenced by EEI, from 2027 through the end of this this NOPR's analysis period.

DOE received no further comment regarding it electricity costs analysis and maintained the approach used in the August 2021 Preliminary Analysis TSD for this NOPR.

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 August 2021 Preliminary Analysis TSD, DOE asserted that maintenance and repair costs do not increase with transformer efficiency. NEMA responded that they agree with these assumptions. (NEMA, No. 50 at p. 16)

Based on this response DOE continued its assumptions that maintenance and repair costs do not increase with transformer efficiency for this NOPR analysis.

8. Equipment Lifetime

For distribution transformers, DOE used a distribution of lifetimes, with an estimated average of 32 years and maximum 60 years.

NEMA commented that they have no alternative lifetimes to suggest, and the equipment lifetimes are suitably representative. (NEMA, No. 50 at p. 16) However, NEMA postulated that, logically, increased (equipment) prices will create pressure on some customers to rebuild existing property. NEMA did not provide the additional service life that would be extended to rebuilt equipment in this event, or to what extent the average service lifetime of a distribution transformer would increase. As the average lifetime presented in the August 2021 Preliminary Analysis TSD, at 32 years, is quite long, for this NOPR, DOE maintained the lifetime estimates presented in the August 2021 Preliminary Analysis TSD.

DOE request the average extension of distribution transformer service life that can be achieved through rebuilding. Additionally, DOE requests comment on the fraction of transformer that are repaired by their original purchasing entity and returned to service, thereby extending the transformer's service lifetime beyond the estimated lifetimes of 32 years with a maximum of 60 years.

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 NOPR, DOE estimated a statistical distribution of commercial customer discount rates that varied by distribution transformer type, by calculating the cost of capital for the different types 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.[80] 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.

EEI commented that DOE should utilize up to date information to apply an appropriate discount rate for electric companies. (EEI, No. 56 at p. 4) DOE understands that this comment is in reference to DOE applying the Federal Government discount rate to local Municipal Utilities (MUNIs) consumers in the LCC analysis in the August 2021 Preliminary Analysis TSD. This was in error and has been corrected in this NOPR; consumer impacts for MUNIs are now calculated using the distribution of state/local government discount rates shown in Table IV.11. The mean WACC for this distribution is 2.67 percent.[81]

TABLE IV.11—APPLIED DISCOUNT RATES FOR PUBLICLY OWNED UTILITIES

Rate bin	Rates (%)	Weight (%)	Observations (quarters)
<0%	−1.9	3.0	4
0–1%	0.9	2.3	3
1–2%	1.6	23.3	31
2–3%	2.5	25.6	34
3–4%	3.5	35.3	47
4–5%	4.2	10.5	14

DOE received no further comments on its discount rate analysis and maintained its approach for this NOPR. 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

[80] 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.

[81] Sources: For values through Q2 2016, Federal Reserve Bank of Saint Louis, ''State and Local Bonds—Bond Buyer Go 20-Bond Municipal Bond Index—Discontinued Series,'' *https://fred.stlouisfed.org/series/WSLB20* (Last accessed February 2022). For Q3 2016 through 2021, Bartel Associates LLC, ''20 Year AA Municipal Bond Quarterly Rates,'' updated January 5, 2022, *https://bartel-associates.com/resources/select-gasb-67-68-discount-rate-indices* (Last accessed February 2022).

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). 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, where distribution transformers are purchased based on either lowest first cost, or, on lowest TOC. 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. This selection is constrained only by purchase-price in the majority of cases (90 percent, and 100 percent for liquid-immerses, and all dry-type transformers, respectively), and reflect the MSPs of the available designs determined in the engineering analysis in section IV.C.1 of this document. The resulting distribution of transformer efficiency in the No-New-Standards Case is shown in Table IV.12.

Comments received regarding the energy efficiency distribution in the no-new-standards case are addressed in the discussion regarding the modeling of distribution transformer purchase decisions, in section IV.F.2 of this document.

See chapter 8 of the NOPR TSD for further information on the derivation of the efficiency distributions.

TABLE IV.12—APPLIED DISTRIBUTION OF EQUIPMENT EFFICIENCIES IN THE NO-NEW STANDARDS CASE, FRACTION OF UNITS AT EACH EL (%)

EC	Rep unit	Efficiency level					
		0	1	2	3	4	5
1	1	90.6	6.1	0.3	0.9	1.6	0.4
1	2	99.1	0.3	0.4	0.1	0.0	0.0
1	3	96.5	1.0	2.2	0.1	0.2	0.1
2	4	65.0	30.7	1.2	0.1	2.1	0.9
2	5	93.5	4.2	1.7	0.6	0.0	0.0
2	17	97.7	0.2	0.3	0.8	0.8	0.2
12	15	64.8	31.4	0.8	0.0	2.1	0.9
12	16	93.9	3.9	1.6	0.4	0.0	0.0
3	6	31.4	46.4	21.3	0.9	0.0	0.0
4	7	83.4	15.1	1.5	0.0	0.0	0.0
4	8	49.0	45.1	6.0	0.0	0.0	0.0
6	9	28.0	50.0	22.0	0.0	0.0	0.0
6	10	87.5	12.5	0.0	0.0	0.0	0.0
8	11	76.2	23.8	0.0	0.0	0.0	0.0
8	12	90.6	9.4	0.0	0.0	0.0	0.0
8	18	100.0	0.0	0.0	0.0	0.0	0.0
10	13	90.4	9.7	0.0	0.0	0.0	0.0
10	14	100.0	0.0	0.0	0.0	0.0	0.0
10	19	100.0	0.0	0.0	0.0	0.0	0.0

Note: may not sum to 100 due to rounding.

11. Payback Period Analysis

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

The inputs to the PBP calculation 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. The PBP calculation uses the same inputs as the LCC analysis, except that discount rates are not needed.

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. The results of this analysis provide an important element of 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 V.B.1.c 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.[82] 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.

DOE projected distribution transformer shipments for the no-new standards case by assuming that long-

[82] 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.

term growth in distribution transformer shipments will be driven by long-term growth in electricity consumption. DOE developed its initial shipments inputs based on data from the previous final rule, and data submitted to DOE from interested parties; these initial shipments are shown for the assumed compliance year, by distribution transformer type, in Table IV.13 through Table IV.15. For this NOPR, DOE received additional data from manufacturers via confidential interviews, resulting in revised shipments estimates for liquid-immersed distribution transformers. DOE developed the shipments projection for liquid-immersed distribution transformers by assuming that annual shipments growth is equal to growth in electricity consumption for all sectors, as given by the *AEO2022* 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.

TABLE IV.13—ESTIMATED LIQUID-IMMERSED SHIPMENTS FOR 2027 (UNITS)

Capacity (kVA)	Single-phase		Three-phase		
	Pad	OH	Pad	OH	NVS
10	677	71,325	0	0	0
15	4,679	147,344	0	0	0
25	44,873	329,589	0	0	0
30	0	0	10	68	0
38	8,184	45,629	0	0	0
45	0	0	714	692	0
50	79,074	149,710	0	0	0
75	42,684	24,149	6,523	661	0
100	32,830	20,537	0	0	0
113	0	0	1,773	95	0
150	0	0	13,066	787	0
167	8,272	5,926	0	0	0
225	0	0	2,972	16	0
250	134	508	0	0	0
300	0	0	13,061	268	0
333	4	890	0	0	0
500	3	488	9,867	0	3
667	6	0	13	0	13
750	0	0	6,057	0	49
833	70	21	39	0	39
1,000	0	0	5,426	0	127
1,500	0	0	5,886	0	150
2,000	0	0	2,349	0	103
2,500	0	0	3,701	0	359
3,750	0	0	286	0	0
5,000	0	0	95	0	0
Total	221,490	796,116	71,838	2,587	843

TABLE IV.14—ESTIMATED LOW-VOLTAGE DRY-TYPE SHIPMENTS FOR 2027 (UNITS)

Capacity (kVA)	Single-phase	Three-phase
10	3	
15	2,792	18,398
25	6,215	
30		44,689
37.5	3,777	
45		47,106
50	5,821	
75	3,508	62,205
100	2,200	
112.3		27,858
150		22,062
167		
225		7,828
250	28	
300		4,109
333		
500		2,527
667		
750		614
833		
1,000		17

TABLE IV.14—ESTIMATED LOW-VOLTAGE DRY-TYPE SHIPMENTS FOR 2027 (UNITS)—Continued

Capacity (kVA)	Single-phase	Three-phase
1,500		11
2,000		
2,500		
Total	24,344	237,423

TABLE IV.15—ESTIMATED MEDIUM-VOLTAGE DRY-TYPE SHIPMENTS FOR 2027 (UNITS)

Capacity (kVA)	Single-phase			Three-phase		
	20–45 kV BIL	46–95 kV BIL	≥96 kV BIL	20–45 kV BIL	46–95 kV BIL	≥96 kV BIL
10	250	180	60	0	0	0
15	250	180	60	5	0	0
25	60	40	20	0	0	0
30	0	0	0	10	0	0
38	60	40	20	0	0	0
45	0	0	0	10	0	0
50	30	20	10	0	0	0
75	30	20	10	4	2	0
100	12	20	6	0	0	0
113	0	0	0	30	4	0
150	0	0	0	35	5	0
167	7	10	3	0	0	0
225	0	0	0	29	12	0
250	15	20	3	0	0	0
300	15	0	0	91	30	25
333	12	20	4	0	0	0
500	0	0	0	177	85	74
667	0	0	0	0	0	0
750	0	0	0	72	121	75
833	0	0	0	0	0	0
1,000	0	0	0	45	242	194
1,500	0	0	0	0	363	244
2,000	0	0	0	0	605	280
2,500	0	0	0	0	605	394
3,750	0	0	0	0	12	8
5,000	0	0	0	0	4	3
Total	741	550	196	508	2,074	1,297

1. Equipment Switching

In response to the shipments analysis presented in the August 2021 Preliminary Analysis TSD, NEMA commented that manufacturers have had customers avoid liquid-immersed entirely and use dry-type designs due to local purchasing restrictions or policies. (NEMA, No. 50 at p. 14)

DOE understands that medium-voltage dry-type distribution transformers (MVDT) can be used as replacement for liquid-immersed distribution transformers but DOE has always considered it as an edge case due to the differences in purchase price, and consumer sensitivity to first costs. DOE does not have sufficient data to model the substitution of liquid-immersed distribution transformers with MVDT.

DOE requests comment on which liquid-immersed distribution transformers capacities are typically replaced with MVDT. DOE further requests data that would indicate a trend in these substitutions. DOE further requests data that would help it determine which types of customers are preforming these substitutions, *e.g.,* industrial customers, invertor owned utilities, MUNIs, *etc.*

2. Trends in Distribution Transformer Capacity (kVA)

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 will cause changes to transformer shipments, unit sizes and selections, and, that DOE should examine non-static capacity scenarios, where kVA of units by type 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. (NEMA, No. 50 at pp. 16–17)

DOE has limited data available to conduct the sensitivity requested by NEMA at this time. To do so DOE would require the current average kVA capacity for each of the representative units analyzed in the engineering analysis, section IV.C.1 of this document. If DOE were to apply a shift in growing capacity without input data from stakeholders, it would have the effect on inflating the energy savings estimates. In response to NEMA's comment DOE requests data to inform a shift in the capacity distribution to larger capacity distribution transformers. Additionally, DOE requests information on the extent that this increasing trend in capacity would affect all types of distribution transformers, or only medium-voltage distribution transformers.

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.[83] (''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 2027 through 2056.

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 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 model. The NIA model uses typical values (as opposed to probability distributions) as inputs.

Table IV.16 summarizes the inputs and methods DOE used for the NIA analysis for the NOPR. Discussion of these inputs and methods follows the table. See chapter 10 of the NOPR TSD for further details.

TABLE IV.16—SUMMARY OF INPUTS AND METHODS FOR THE NATIONAL IMPACT ANALYSIS

Inputs	Method
Shipments	Annual shipments from shipments model. *Initial Shipments:* Market reports from HVOLT, stakeholder data, confidential manufacturer data. *Future Shipments:* Projection based on trends from AEO2022: *Liquid-immersed:* Future electricity sales trends. *Low-, Medium-voltage* Dry-type: Future commercial floor space and industrial output trends.
Compliance Date of Standard	2027.
Efficiency Trends	No-new-standards case: constant efficiency over time. Standards cases: constant efficiency 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	*AEO2022* projections (to 2050) and constant 2050 thereafter.
Energy Site-to-Primary and FFC Conversion	A time-series conversion factor based on *AEO2022.*
Discount Rate	3 percent and 7 percent.
Present Year	2022.

DOE projected the energy savings, operating cost savings, product costs, and NPV of consumer benefits over the lifetime of distribution transformers sold from 2027 through 2056 Given the extremely durable nature of distribution transformers, this creates an analytical timeframe from 2027 through 2115. DOE seeks comment on the current analytical timeline, and potential alternative analytical timeframes.

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 standards cases. Section IV.F.3of 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, 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 to establish the shipment-weighted efficiency for the year of potential standards are assumed to become effective (2027). For this NOPR, 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 potential standards case (''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

[83] The NIA accounts for impacts in the 50 states and U.S. territories.

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 *AEO2022.* 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 per-unit load (PUL) on the distribution transformer. Any increase in distribution transformer PUL is coincidental, and not related to rebound effect.

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 IV.E.3 for more details on DOE approach to load growth.

Because DOE did not find any data to support the inclusion of a rebound effect specific to distribution transformers, did not include a rebound effect in this NOPR.

DOE requests comment on its assumption that including a rebound effect is inappropriate for distribution transformers.

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 [84] 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 NOPR 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 2056. 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 2003–2019 and (2) a low price decline case based on the years between 1967–2002. 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 *AEO2022,* 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 *AEO2022* 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 NOPR TSD.

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. For this NOPR, 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.[85] 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

[84] For more information on NEMS, refer to *The National Energy Modeling System: An Overview 2009,* DOE/EIA–0581(2009), October 2009. Available at *www.eia.gov/forecasts/aeo/index.cfm* (last accessed April 1, 2022).

[85] United States Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. Section E. Available at *www.whitehouse.gov/omb/memoranda/m03-21.html* (last accessed April 1, 2022).

subgroups. Chapter 11 in the NOPR TSD describes the consumer subgroup analysis.

1. Utilities Serving Low Customer Populations

In rural areas, mostly served by municipal utilities (MUNIs) the number of customers per distribution transformer is lower than in metropolitan areas and may result in lower PULs. For this NOPR, as in the April 2013 Standards Final Rule, DOE reduced the PUL by adjusting the distribution of *IPLs*, as discussed in section IV.E.1.a resulting in the PULs shown below in Table IV.17. Further, DOE altered the customer sample to limit the distribution of discount rates to those observed by State and local governments discussed in IV.F.9. DOE notes that while MUNIs deploy a range of distribution transformers to serve their customers, in low population densities the most common unit is a 25 kVA pole overheard liquid-immersed distribution transformer, which is represented in this analysis as representative unit 2.

TABLE IV.17—DISTRIBUTION OF PER-UNIT-LOAD FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS OWNED BY UTILITIES SERVING LOW POPULATIONS

Rep. unit	Mean RMS	Mean IPL	Mean PUL
1	0.29	0.60	0.18
2	0.27	0.60	0.16
3	0.32	0.60	0.19
4	0.26	0.60	0.15
5	0.31	0.60	0.19

DOE requests comment on the mean PUL applied to distribution transformers owned and operated by utilities serving low customer populations.

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 structure, referred to as vaults. At issue in the potential amended standards case is that as 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).

NEMA commented that they agree with the proposed approach to examine utility costs regarding replacement of existing vault and subsurface transformers. (NEMA No 18 at p. 17).

DOE has not received any data from stakeholders regarding the costs associated with vault replacement due increased distribution transformer volume. For this subgroups analysis DOE examined the National average price of concrete vault construction with 6-inch-thick walls for variously sized vaults from RSMeans.[86] DOE notes that the costs required to install a new vault can vary above the cost of the prefabricated concrete vault. These additional costs would include but are not limited to, excavation and disposal of the original vault, and backfilling. While stakeholders have discussed that these costs can be prohibitive, they have not to date provided examples of such costs, or itemized cost breakdowns associated with vault replacement. Due to this lack of information DOE has taken a simple approach and multiplied the costs from RSMeans by three to provide a gross vault installation estimate. This gross vault installation estimate represents the labor time and material costs associated with excavation, vault installation, and backfilling when replacing the no-new-standards vault with a new structure. DOE applied the following simple linear fit relating the cost of vault replacement to transformer volume.

$$VaultReplacement = 24.201 \times DTVolume + 4{,}930.8$$

TABLE IV.18—VAULT REPLACEMENT COSTS

[2021$]

Vault dimensions (ft)	Volume (ft^3)	Replacement cost (2021$)
5′ × 10′ × 6′ high	300	12,450
5′ × 12′ × 6′ high	360	13,050
6′ × 10′ × 6′ high	360	13,050
6′ × 12′ × 6′ high	360	14,625
6′ × 13′ × 6′ high	468	18,300
8′ × 14′ × 7′ high	784	23,550

DOE requests comment on its assumed vault replacement costs methodology. DOE seeks comment or data regarding the installation procedures associated with vault replacement. vault expansion (renovation), and vault transformer installation and their respective costs for replacement transformers. Additionally, DOE seeks information on the typical expected lifetime of underground concrete vaults.

[86] RSMeans, Series: 330563130050, 330563130150, 330563130100, 330563130200, 330563130250, 330563130300, *https://www.rsmeans.com/* (Last access: March 15, 2022).

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, product 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 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 NOPR 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 information from the April 2013 Standards Final Rule, individual company filings of form 10–K from the SEC,[87] corporate annual reports, the U.S. Census Bureau's *Economic Census,*[88] and reports from D&B Hoovers.[89]

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, industry consolidation, and manufacturer subgroup impacts.

In Phase 3 of the MIA, DOE conducted structured, detailed interviews with representative 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. See section IV.J.3 of this document for a description of the key issues raised by manufacturers during the interviews. 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 NOPR 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, 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 2022 (the reference year of the analysis) and continuing to 2056. 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 low-voltage dry-type distribution transformers, and 9.0 percent for medium-voltage dry-type distribution transformers, which was derived from the April 2013 Standards Final Rule and then modified according to feedback received during manufacturer interviews.[90]

[87] *www.sec.gov/edgar.shtml.*

[88] *www.census.gov/programs-surveys/asm.html.*

[89] *www.app.avention.com.*

[90] See Chapter 12 of the April 2013 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 Final Rule, DOE initially calculated a 9.1 percent discount rate,

DOE requests comment on the real discount rates used in this NOPR. Specifically, if 7.4 percent for liquid-immersed distribution transformer manufacturers, 11.1 percent for low-voltage dry-type distribution transformer manufacturers, and 9.0 percent for medium-voltage dry-type distribution transformer manufacturers are appropriate discount rates to use in the GRIM.

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 shipments analysis, and information gathered from industry stakeholders during the course of manufacturer interviews. The GRIM results are presented in section V.B.2. Additional details about the GRIM, the discount rate, and other financial parameters can be found in chapter 12 of the NOPR 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 products 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 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 NOPR 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 2022 (the reference year) to 2056 (the end year of the analysis period). See chapter 9 of the NOPR 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 product designs comply with amended energy conservation standards. Capital conversion costs are investments in property, plant, 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 amended standards at each TSL for each representative unit. To do this, DOE used equipment cost estimates from the April 2013 Standards Final Rule and from information provided by manufacturers and equipment suppliers, an understanding of the manufacturing processes at distribution transformer manufacturing facilities developed during interviews and in consultation with subject matter experts, and the properties associated with different core and winding materials. Major drivers of capital conversion costs include changes in core steel type (and thickness), core weight, and core stack height, all of which are interdependent and can vary by efficiency level. DOE uses estimates of the core steel quantities needed by steel type for each TSL to model the additional equipment the industry would need to meet each TSL.

Capital conversion costs are primarily driven at each TSL by the potential need for the industry to expand capacity for amorphous production. Based on interviews with manufacturers and equipment suppliers, based on the responses, DOE's model assumed an amorphous production line capable of producing 1,200 tons annual of amorphous cores would cost approximately $1,000,000 in capital investments. This includes costs associated with purchasing annealing ovens, core cutting machines, lacing tables, and other miscellaneous equipment. The quantity of amorphous steel are outputs of the engineering analysis and the LCC. At higher TSLs, the percent of distribution transformers selected in the LCC consumer choice model that have amorphous cores increases. Additionally, at the highest TSLs, the quantity of amorphous steel per distribution transformer also increases. As the increasing stringency of the TSLs drive the use of amorphous cores in distribution transformers, capital conversion costs increase.

For product conversion costs, DOE understands the production of amorphous cores requires unique expertise and equipment. For manufacturers without experience with amorphous steel, a standard that would likely be met using amorphous cores would require the development or the procurement of the technical knowledge to produce cores. Because amorphous steel is thinner and more brittle after annealing, materials management, safety measures, and design considerations that are not associated with non-amorphous steels would need to be implemented.

DOE estimated product conversion costs would be equal to the annual industry R&D expenses for those TSLs 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, and other R&D efforts the industry would have to undertake to move to a predominately amorphous market. For TSLs that would

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 this NOPR, manufacturers continued to agree that using different discount rates for each equipment class group is appropriate.

not require the use of amorphous cores, but would still require distribution transformer models to be redesigned to meet higher efficiency levels, DOE estimated product conversion costs would be equal to 50 percent the 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.

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 the 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 of this document. For additional information on the estimated capital and product conversion costs, see chapter 12 of the NOPR 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 manufacturer markups to the MPCs estimated in the engineering analysis for each equipment class and efficiency level. Modifying these margins in the standards case yields different sets of impacts on manufacturers. For the MIA, DOE modeled two standards-case 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 percentage markup scenario; and (2) a preservation of operating profit scenario. These scenarios lead to different margins that, when applied to the MPCs, result in varying revenue and cash flow impacts on distribution transformer manufacturers.

Under the preservation of gross margin percentage scenario, DOE applied the same single uniform ''gross margin percentage'' that is used in the no-new-standards case across all efficiency levels in the standards cases. 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.[91] 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 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 cost of production (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 scenarios is presented in section V.B.2.a of this document.

3. Manufacturer Interviews

DOE interviewed manufacturers representing approximately 60 percent of the liquid-immersed distribution transformer industry; approximately 50 percent of the LVDT distribution transformer industry; and approximately 60 percent of the MVDT distribution transformer industry.

In interviews, DOE asked manufacturers to describe their major concerns regarding this rulemaking. The following section highlights manufacturer concerns that helped inform the projected potential impacts of an amended standard on the industry.

[91] The gross margin percentage of 20 percent is based on a manufacturer markup of 1.25.

Manufacturer interviews are conducted under non-disclosure agreements (''NDAs''), so DOE does not document these discussions in the same way that it does public comments in the comment summaries and DOE's responses throughout the rest of this document.

a. Material Shortages and Prices

Throughout interviews and comments, manufacturers noted substantial material shortages leading to both higher, more volatile prices and, at points, an inability to procure certain materials—particularly electrical steel. Manufacturers noted that these shortages reflect rising demand for electrical steel domestically and internationally as well as more general supply chain issues caused by the COVID–19 pandemic. Demand for steel, according to manufacturers, appears to be driven by the growing electric vehicles and electric motors sectors (prompting some steel producers to shift production away from GOES suited for core manufacturing to non-grain-oriented steels suited for electric vehicle production) as well as more general rising demand for electrical steel abroad (leading to foreign steel producers reducing exports to the United States). Manufacturers also noted that prices for copper and aluminum have risen substantially, though have not been subject to allocations as electrical steel has.

Manufacturers stated that higher energy conservation standards will most likely lead to greater demand for materials necessary to build more efficient transformers—potentially leading to less material availability and greater cost concerns, particularly for manufacturers without long-term relationships with suppliers. Further, several manufacturers argued that establishing more stringent energy conservation standards during a period of material price volatility may undermine DOE's analysis as it relates to the short-term and long-term economic impact of such a standard.

b. Use of Amorphous Materials

Manufacturers raised concerns about energy conservation standards that would require the use of amorphous steel cores. Manufacturers who currently make their own cores stated that amorphous core production requires a different manufacturing process that would require a substantial amount of new capital equipment and retrofits of existing equipment that could, additionally, require more facility floor space. Some manufacturers noted that they may need to switch to purchasing cores for products covered by energy conservation standards. Moving from a lower to a higher grade of non-amorphous steel would result in significantly less costs and most manufacturers could continue to use the same core production equipment. Manufacturers that currently purchase cores noted less capital conversion costs associated with such an increase in standards but did note that there is a limited number of suppliers of amorphous steel grades both in North America and globally—potentially meaning a limited supply of amorphous steel in a market with relatively little competition.

c. Larger Distribution Transformers

Manufacturers noted that energy conservation standard increases, short of requiring amorphous core usage, would likely lead to larger distribution transformers. Manufacturers stated that larger transformer sizes could complicate efforts to design transformers to replace existing transformers where space is limited. Utilities, for example, have built vaults, where distribution transformers are placed, of a certain size. If a replacement distribution transformer cannot be designed to fit the current vault space, then utilities will need to build new vaults, increasing costs and construction-related disruption significantly. Manufacturers indicated that this was not a significant issue with new construction projects, where infrastructure can be built around the size of the distribution transformer.

4. Discussion of MIA Comments

In response to the August 2021 Preliminary Analysis TSD, a few interested parties made comments regarding the MIA, including comments on small businesses and capital equipment. DOE addresses these comments in this section.

a. Small Businesses

Powersmiths commented that large manufacturers are likely to be able to meet higher efficiency standards given they will likely have the resources to make the necessary capital investments to comply with standards and would likely gain additional revenue from the higher per transformer prices. However, if energy conservation standards require large capital investments, these costs could put small businesses out of business. (Powersmiths, No.46 at p. 6) While Schneider commented that there is an increase in the number of companies that produce assembled cores for distribution transformer manufacturers (as opposed to distribution transformer manufacturers being required to fabricate their own cores internally). Schneider continued stating that the availability to purchase assembled cores would not place a disproportionate burden on small businesses. (Schneider, No. 49 at p. 15)

DOE agrees that large capital and production conversion costs could put additional strains on all distribution transformer manufacturers, and especially small business. As part of the MIA DOE calculates the expected conversion costs (capital and product conversion costs). The methodology for calculating these conversion costs are described in section IV.J.2.c and these cost estimates are presented in section V.B.2.a. Additionally, DOE specifically examines the potential impact of small businesses in section VI.B of this document.

As stated in section IV.J.2.c, conversion costs are primarily driven by the costs associated with the production of amorphous cores, and to a lesser extent larger and more efficient GOES cores. DOE agrees with Schneider's comment that small businesses could mitigate larger conversion costs by purchasing assembled cores as opposed to making the investments to produce more efficient GOES cores or amorphous cores, in order to comply with the analyzed standards.

b. Capital Equipment

ERMCO comments that larger cores may require new or different manufacturing equipment. (ERMCO, No. 45 at p. 1) DOE agrees that while capital conversion costs are primarily driven by the costs associated with the production of amorphous cores, there are capital conversion costs associated with production of larger cores. DOE accounts for the need for manufacturers to purchase new or different equipment in the capital conversion cost estimates described in section IV.J.2.c, with these cost estimates 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 to 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 factors 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 NOPR TSD. The analysis presented in this notice uses projections from *AEO2022*. 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).[92]

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 NOPR 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. *AEO2022* generally represents current legislation and environmental regulations, including recent government actions, that were in place at the time of preparation of *AEO2022,* including the emissions control programs discussed in the following paragraphs.[93]

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

[92] Available at *www.epa.gov/sites/production/files/2021-04/documents/emission-factors_apr2021.pdf* (last accessed July 12, 2021).

[93] For further information, see the Assumptions to *AEO2022* 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 June, 2022).

cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (DC). (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.[94] *AEO2022* 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).[95] 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, 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. 77 FR 9304 (Feb. 16, 2012). In the MATS final rule, EPA established a standard for hydrogen chloride as a surrogate for acid gas hazardous air pollutants (''HAP''), and also established a standard for SO_2 (a non-HAP acid gas) as an alternative equivalent surrogate standard for acid gas HAP. The same controls are used to reduce HAP and non-HAP acid gas; thus, SO_2 emissions are being reduced as a result of the control technologies installed on coal-fired power plants to comply with the MATS requirements for acid gas. 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. 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 would generally reduce SO_2 emissions. DOE estimated SO_2 emissions reduction using emissions factors based on *AEO2022*.

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 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. A different case could possibly result, depending on the configuration of the power sector in the different regions and the need for allowances, such that NO_X emissions might not remain at the limit in the case of lower electricity demand. In this case, energy conservation 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. Energy conservation standards would be expected to reduce NO_X emissions in the States not covered by CSAPR. DOE used *AEO2022* 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 *AEO2022,* which incorporates the MATS.

L. Monetizing Emissions Impacts

As part of the development of this proposed 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 NOPR.

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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and presents monetized greenhouse gas abatement benefits where appropriate and permissible under law. DOE requests comment on how to address the climate benefits and non-monetized effects of the proposal.

1. Monetization of Greenhouse Gas Emissions

For the purpose of complying with the requirements of Executive Order 12866, DOE estimates the monetized benefits of the reductions in emissions of CO_2, CH_4, and N_2O by using a measure of the social cost (''SC'') of each pollutant (*e.g.,* SC–GHGs). 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

[94] 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).

[95] In Sept. 2019, the D.C. Court of Appeals remanded the 2016 CSAPR Update to EPA. In April 2021, EPA finalized the 2021 CSAPR Update which resolved the interstate transport obligations of 21 states for the 2008 ozone NAAQS. 86 FR 23054 (April 30, 2021); *see also,* 86 FR 29948 (June 4, 2021) (correction to preamble). The 2021 CSAPR Update became effective on June 29, 2021. The release of AEO 2021 in February 2021 predated the 2021 CSAPR Update.

Executive orders and guidance, and DOE would reach the same conclusion presented in this proposed rulemaking in the absence of the social cost of greenhouse gases, including the February 2021 Interim Estimates presented by the Interagency Working Group on the Social Cost of Greenhouse Gases.

DOE estimated the global social benefits of CO_2, CH_4, and N_2O reductions (*i.e.,* SC–GHGs) using the 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 Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) (IWG, 2021). The SC–GHGs 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, SC–GHGs 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–GHGs therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC–GHGs 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), the 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.

The SC–GHGs estimates presented here were developed over many years, using transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the 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 social cost of carbon (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 (ECS)—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 social cost of methane (SC–CH_4) and nitrous oxide (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. (2015) 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 (National Academies, 2017). 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 of the National Academies (2017). 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 proposed rulemaking. The E.O. instructs the IWG to undertake a fuller update of the SC–GHG estimates by January 2022 that takes into consideration the advice of the National Academies (2017) 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 effects omitted 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, and 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 proposed 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 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue only 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 (7 percent under current OMB 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 (2017) 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 (IWG 2010, 2013, 2016a, 2016b), and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates. As a member of the IWG involved in the development of the February 2021 SC–GHG TSD, DOE agrees with this assessment and will continue to follow developments in the literature pertaining to this issue.

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 Circular A–4, as published in 2003, recommends using 3% and 7% 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% discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this analysis. 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 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.''

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 to 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 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. 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–CO2 estimates. However, as discussed in the February 2021 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–GHG (*i.e.,* 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 pollutants are presented in section V.B.6 of this document.

a. Social Cost of Carbon

The SC–CO_2 values used for this NOPR were generated using the values presented in the 2021 update from the IWG's February 2021 TSD. Table IV.19 shows the updated sets of SC–CO_2 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 NOPR TSD. For purposes of capturing the uncertainties involved in regulatory impact analysis, DOE has determined it is appropriate to include all four sets of SC–CO_2 values, as recommended by the IWG.[96]

TABLE IV.19—ANNUAL SC–CO_2 VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2070

[2020$ per metric ton CO_2]

Emissions year	Discount rate and statistics: 5%, average	3%, average	2.5%, average	3%, 95th percentile
2020	14	51	76	151
2025	17	56	83	169
2030	19	62	89	186
2035	22	67	96	205
2040	25	73	103	224
2045	28	79	109	242
2050	32	84	116	259
2055	35	89	122	265
2060	38	93	128	275
2065	44	100	135	300
2070	49	108	143	326

The SC–CO_2 values used for this NOPR were based on the values presented in the 2021 update from the IWG's February 2021 SC–GHG TSD. For 2051 to 2070, DOE used estimates published by EPA, adjusted to 2021$.[97] These estimates are based on methods, assumptions, and parameters identical to the 2020–2050 estimates published by the IWG. DOE expects additional climate benefits to accrue for any longer-life transformers post 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. If further analysis of monetized climate benefits beyond 2070 becomes available prior to the publication of the final rule, DOE will include that analysis in the final rule. 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. 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 NOPR were generated using the values presented in the February 2021 TSD. Table IV.20 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 NOPR 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.

TABLE IV.20—ANNUAL SC–CH_4 AND SC–N_2O VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2070

[2020$ per metric ton]

Year	SC–CH_4—discount rate and statistic				SC–N_2O—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	663	1,480	1,946	3,893	5,760	18,342	27,037	48,090

[96] For example, the February 2021 TSD discusses how the understanding of discounting approaches suggests that discount rates appropriate for intergenerational analysis in the context of climate change may be lower than 3 percent.

[97] See EPA, *Revised 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards: Regulatory Impact Analysis,* Washington, DC, December 2021. Available at: *www.epa.gov/system/files/documents/2021-12/420r21028.pdf* (last accessed January 13, 2022).

TABLE IV.20—ANNUAL SC–CH_4 AND SC–N_2O VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2070—Continued

[2020$ per metric ton]

Year	SC–CH_4—discount rate and statistic				SC–N_2O—discount rate and statistic			
	5%	3%	2.5%	3%	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile	Average	Average	Average	95th percentile
2025	799	1,714	2,223	4,533	6,766	20,520	29,811	54,108
2030	935	1,948	2,499	5,173	7,772	22,698	32,585	60,125
2035	1,106	2,224	2,817	5,939	9,007	25,149	35,632	66,898
2040	1,277	2,500	3,136	6,705	10,241	27,600	38,678	73,670
2045	1,464	2,778	3,450	7,426	11,687	30,238	41,888	80,766
2050	1,651	3,057	3,763	8,147	13,133	32,875	45,098	87,863
2055	1,772	3,221	3,942	8,332	14,758	35,539	48,236	94,117
2060	1,899	3,395	4,130	8,539	16,424	38,300	51,507	100,845
2065	2,508	4,163	4,960	11,177	19,687	42,625	56,397	115,590
2070	3,130	4,976	5,867	14,079	23,018	47,072	61,428	130,928

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. 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.

2. Monetization of Other Emissions Impacts

For the NOPR, DOE estimated the monetized value of NO_X and SO_2 emissions reductions from electricity generation using the latest benefit per ton estimates for that sector from the EPA's Benefits Mapping and Analysis Program.[98] 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 2030, 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. DOE derived values specific to the sector for distribution transformer using a method described in appendix 14B of the NOPR TSD.

DOE multiplied the site emissions reduction (in tons) in each year by the associated $/ton values, and then discounted each series using discount rates of 3 percent and 7 percent as appropriate.

M. Utility Impact Analysis

The utility impact analysis estimates several effects on the electric power generation industry that would result from the adoption of new or amended energy conservation standards. The utility impact analysis estimates the changes in installed electrical capacity and generation that would result for each TSL. The analysis is based on published output from the NEMS associated with *AEO2022*. 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 *AEO2022* Reference case and various side cases. Details of the methodology are provided in the appendices to chapters 13 and 15 of the NOPR 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 proposed 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.[99] 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

[98] *Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 21 Sectors. www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-21-sectors.*

[99] See U.S. Department of Commerce–Bureau of Economic Analysis. *Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II).* 1997. U.S. Government Printing Office: Washington, DC. Available at *apps.bea.gov/scb/pdf/regional/perinc/meth/rims2.pdf (last accessed June 1, 2022).*

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 NOPR using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 4 (''ImSET'').[100] ImSET is a special-purpose version of the ''U.S. Benchmark National Input-Output'' (''I–O'') model, which was designed to estimate the national employment and income effects of energy-saving technologies. The ImSET software includes a computer-based I–O model having structural coefficients that characterize economic flows among 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 the uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Because ImSET does not incorporate price changes, the employment effects predicted by ImSET may over-estimate actual job impacts over the long run for this rule. Therefore, DOE used ImSET only to generate results for near-term timeframes (2031), where these uncertainties are reduced. For more details on the employment impact analysis, see chapter 16 of the NOPR 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 proposing to adopt in this NOPR. Additional details regarding DOE's analyses are contained in the NOPR TSD supporting this document.

A. Trial Standard Levels

In general, DOE typically evaluates potential 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 market cross elasticity from consumer purchasing decisions that may change when different standard levels are set. DOE presents the results for the TSLs in this document, while the results for all efficiency levels that DOE analyzed are in the NOPR TSD.

In the analysis conducted for this NOPR, DOE analyzed the benefits and burdens of five TSLs for distribution transformers. DOE developed TSLs that combine efficiency levels for each analyzed representative unit and their respective equipment classes. For this NOPR, DOE defined its efficiency levels as a percentage reduction in baseline losses (see section IV.F.2). To create TSLs, DOE maintained this approach and directly mapped ELs to TSLs, with the exception of liquid-immersed submersible distribution transformers which remain at baseline for all TSLs except max-tech. For submersible distribution transformers, being able to fit in an existing vault is a consumer feature of significant 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 NOPR TSD.

Table V.1 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 10 percent for 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.1—EFFICIENCY LEVEL TO TRIAL STANDARD LEVEL MAPPING FOR DISTRIBUTION TRANSFORMERS

Equipment type	EC	RU	Phases	BIL	Trial standard level				
					1	2	3	4	5
Liquid-immersed	1	1	1	*All*	1	2	3	4	5
	1	2	1	*All*	1	2	3	4	5
	1	3	1	*All*	1	2	3	4	5
	2	4	3	*All*	1	2	3	4	5

[100] 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 Guide.* 2015. Pacific Northwest National Laboratory: Richland, WA. PNNL–24563.

TABLE V.1—EFFICIENCY LEVEL TO TRIAL STANDARD LEVEL MAPPING FOR DISTRIBUTION TRANSFORMERS—Continued

Equipment type	EC	RU	Phases	BIL	Trial standard level				
					1	2	3	4	5
	2	5	3	*All*	1	2	3	4	5
	2	17	3	*All*	1	2	3	4	5
	12	15	3	*All*	0	0	0	0	5
	12	16	3	*All*	0	0	0	0	5
Low-voltage Dry-type	3	6	1	*All*	1	2	3	4	5
	4	7	3	*All*	1	2	3	4	5
	4	8	3	*All*	1	2	3	4	5
Medium-voltage Dry-type	5	*9V	1	<46 kV	1	2	3	4	5
	5	10V	1	<46 kV	1	2	3	4	5
	6	9	3	<46 kV	1	2	3	4	5
	6	10	3	<46 kV	1	2	3	4	5
	7	11V	1	≥46 and <96 kV	1	2	3	4	5
	7	12V	1	≥46 and <96 kV	1	2	3	4	5
	8	11	3	≥46 and <96 kV	1	2	3	4	5
	8	12	3	≥46 and <96 kV	1	2	3	4	5
	8	18	3	≥46 and <96 kV	1	2	3	4	5
	9	13V	1	≥96 kV	1	2	3	4	5
	9	14V	1	≥96 kV	1	2	3	4	5
	10	13	3	≥96 kV	1	2	3	4	5
	10	14	3	≥96 kV	1	2	3	4	5
	10	19	3	≥96 kV	1	2	3	4	5

DOE constructed the TSLs for this NOPR to include ELs representative of ELs with similar characteristics (*i.e.,* using similar technologies and/or efficiencies, and having roughly comparable equipment availability). 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.[101]

B. Economic Justification and Energy Savings

1. Economic Impacts on Individual Consumers

DOE analyzed the economic impacts on distribution transformers 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. 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. Chapter 8 of the NOPR TSD provides detailed information on the LCC and PBP analyses.

Liquid-Immersed Distribution Transformers

TABLE V.2—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 1

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	2,917	67	1,346	4,263		31.9
1	2,983	66	1,328	4,311	86.7	31.9
2	3,073	65	1,299	4,373	73.0	31.9
3	3,294	48	969	4,263	19.2	31.9
4	3,279	45	913	4,192	16.0	31.9
5	4,080	39	778	4,859	40.9	31.9

Rep unit 1 represents 20.3 percent of liquid-immersed distribution transformers units shipped, and 21.8 percent of shipments for equipment class 1 (single phase liquid-immersed).

[101] Efficiency levels that were analyzed for this NOPR are discussed in section IV.F.2 of this document. Results by efficiency level are presented in TSD chapters 8, 10, and 12.

TABLE V.3—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 1

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	68.8	−53
2	85.5	−114
3	47.4	0
4	33.7	72
5	95.6	−599

Rep unit 1 represents 20.3 percent of liquid-immersed distribution transformers units shipped, and 21.8 percent of shipments for equipment class 1 (single phase liquid-immersed).
* The savings represent the average LCC for affected consumers.

TABLE V.4—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 2

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	1,805	41	818	2,623		31.9
1	1,805	33	673	2,478	0.1	31.9
2	1,810	30	613	2,423	0.5	31.9
3	1,857	29	580	2,437	4.1	31.9
4	1,951	27	541	2,492	10.1	31.9
5	2,347	23	452	2,799	29.1	31.9

Rep unit 2 represents 72.7 percent of liquid-immersed distribution transformers units shipped, and 78.0 percent of shipments for equipment class 1 (single phase liquid-immersed).

TABLE V.5—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 2

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	21.9	146
2	9.6	201
3	9.3	186
4	13.3	131
5	84.3	−176

Rep unit 2 represents 72.7 percent of liquid-immersed distribution transformers units shipped, and 78.0 percent of shipments for equipment class 1 (single phase liquid-immersed).
* The savings represent the average LCC for affected consumers.

TABLE V.6—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 3

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	10,728	427	8,523	19,251		31.8
1	11,269	335	6,900	18,169	5.9	31.8
2	11,304	323	6,668	17,972	5.6	31.8
3	11,754	305	6,284	18,038	8.4	31.8
4	12,568	275	5,656	18,225	12.2	31.8
5	14,920	234	4,744	19,664	21.8	31.8

Rep unit 3 represents 0.2 percent of liquid-immersed distribution transformers units shipped, and 0.2 percent of shipments for equipment class 1 (single phase liquid-immersed).

TABLE V.7—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 3

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	27.9	1,121
2	22.2	1,312
3	23.3	1,216

TABLE V.7—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 3—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
4	22.5	1,029
5	64.5	−414

Rep unit 3 represents 0.2 percent of liquid-immersed distribution transformers units shipped, and 0.2 percent of shipments for equipment class 1 (single phase liquid-immersed).
* The savings represent the average LCC for affected consumers.

TABLE V.8—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 4

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	10,319	196	3,913	14,232		32.0
1	10,403	193	3,846	14,249	25.8	32.0
2	10,596	184	3,689	14,285	24.1	32.0
3	11,095	137	2,768	13,863	13.1	32.0
4	11,120	129	2,616	13,736	11.9	32.0
5	11,798	117	2,359	14,156	18.7	32.0

Rep unit 4 represents 4.6 percent of liquid-immersed distribution transformers units shipped, and 68.0 percent of shipments for equipment class 2 (three phase liquid-immersed).

TABLE V.9—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 4

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	38.2	−26
2	66.6	−55
3	24.8	381
4	12.9	511
5	48.9	77

Rep unit 4 represents 4.6 percent of liquid-immersed distribution transformers units shipped, and 68.0 percent of shipments for equipment class 2 (three phase liquid-immersed).
* The savings represent the average LCC for affected consumers.

TABLE V.10—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 5

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	35,245	1,195	23,754	58,999		31.7
1	36,431	1,079	21,647	58,078	10.2	31.7
2	36,603	1,006	20,349	56,952	7.2	31.7
3	37,550	966	19,573	57,123	10.0	31.7
4	39,455	891	18,002	57,457	13.8	31.7
5	52,032	744	14,880	66,912	37.2	31.7

Rep unit 5 represents 2.1 percent of liquid-immersed distribution transformers units shipped, and 31.5 percent of shipments for equipment class 2 (three phase liquid-immersed).

TABLE V.11—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 5

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	41.0	986
2	26.7	2,095
3	28.7	1,888
4	28.5	1,543

TABLE V.11—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 5—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
5	95.8	−7,913

Rep unit 5 represents 2.1 percent of liquid-immersed distribution transformers units shipped, and 31.5 percent of shipments for equipment class 2 (three phase liquid-immersed).
* The savings represent the average LCC for affected consumers.

TABLE V.12—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 15

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	10,749	196	3,919	14,668		32.0
1	10,833	193	3,855	14,687	26.3	32.0
2	11,026	185	3,700	14,727	24.5	32.0
3	11,523	137	2,778	14,301	13.1	32.0
4	11,548	129	2,628	14,176	12.0	32.0
5	12,228	117	2,367	14,595	18.8	32.0

Rep unit 15 represents <0.1 percent of liquid-immersed distribution transformers units shipped, and 0.4 percent of equipment class 12 shipments.

TABLE V.13—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 15

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	38.3	−30
2	67.3	−61
3	24.5	379
4	12.8	507
5	49.4	74

Rep unit 15 represents <0.1 percent of liquid-immersed distribution transformers units shipped, and 0.4 percent of shipments for equipment class 12 (three phase liquid-immersed submersible).
* The savings represent the average LCC for affected consumers.

TABLE V.14—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 16

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	35,814	1,255	25,345	61,159		32.1
1	37,015	1,146	23,365	60,380	11.0	32.1
2	37,183	1,085	22,313	59,496	8.0	32.1
3	38,135	1,045	21,549	59,684	11.1	32.1
4	40,044	961	19,748	59,791	14.4	32.1
5	52,622	789	16,044	68,666	36.1	32.1

Rep unit 16 represents 0.1 percent of liquid-immersed distribution transformers units shipped, and 99.6 percent of shipments for equipment class 12 (three phase liquid-immersed submersible).

TABLE V.15—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 16

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	42.0	829
2	28.9	1,700
3	32.3	1,482
4	29.5	1,368

TABLE V.15—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 16—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
5	95.1	−7,509

Rep unit 16 represents 0.1 percent of liquid-immersed distribution transformers units shipped, and 99.6 percent of shipments for equipment class 12 (three phase liquid-immersed submersible).
* The savings represent the average LCC for affected consumers.

TABLE V.16—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 17

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	55,256	3,485	71,294	126,550		32.1
1	70,709	2,485	50,618	121,327	15.5	32.1
2	72,775	2,283	47,047	119,822	14.6	32.1
3	74,623	2,208	45,574	120,197	15.2	32.1
4	78,307	2,028	41,715	120,023	15.8	32.1
5	102,728	1,650	33,556	136,283	25.9	32.1

Rep unit 17 represents <0.1 percent of liquid-immersed distribution transformers units shipped, and 0.5 percent of shipments for equipment class 2 (three phase liquid-immersed).

TABLE V.17—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 17

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	42.8	5,346
2	34.2	6,873
3	36.8	6,472
4	41.5	6,594
5	73.9	−9,755

Rep unit 17 represents <0.1 percent of liquid-immersed distribution transformers units shipped, and 0.5 percent of shipments for equipment class 2 (three phase liquid-immersed).
* The savings represent the average LCC for affected consumers.

Low-Voltage Dry-Type Distribution Transformers

TABLE V.18—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 6

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	1,737	97	1,424	3,161		31.9
1	1,735	90	1,327	3,063	0.0	31.9
2	1,783	83	1,220	3,003	3.3	31.9
3	1,890	77	1,127	3,017	7.6	31.9
4	2,144	62	908	3,053	11.7	31.9
5	2,311	48	703	3,014	11.7	31.9

Rep unit 6 represents 9.3 percent of low-voltage dry-type distribution transformers units shipped, and 100.0 percent of shipments for equipment class 3 (single phase low-voltage dry-type).

TABLE V.19—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 6

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	1	312

TABLE V.19—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 6—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
2	17	203
3	33	146
4	43	108
5	40	147

* The savings represent the average LCC for affected consumers.
Rep unit 6 represents 9.3 percent of low-voltage dry-type distribution transformers units shipped, and 100.0 percent of shipments for equipment class 3 (single phase low-voltage dry-type).

TABLE V.20—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 7

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	3,974	228	3,366	7,340	....	32.1
1	3,929	211	3,114	7,043	0.0	32.1
2	3,920	206	3,029	6,950	0.0	32.1
3	4,266	193	2,842	7,108	8.2	32.1
4	4,621	143	2,102	6,723	7.5	32.1
5	4,829	132	1,947	6,776	8.9	32.1

Rep unit 7 represents 84.9 percent of low-voltage dry-type distribution transformers units shipped, and 93.6 percent of shipments for equipment class 4 (three phase low-voltage dry-type).

TABLE V.21—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 7

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	8	357
2	7	397
3	28	233
4	9	617
5	15	564

* The savings represent the average LCC for affected consumers.
Rep unit 7 represents 84.9 percent of low-voltage dry-type distribution transformers units shipped, and 93.6 percent of shipments for equipment class 4 (three phase low-voltage dry-type).

TABLE V.22—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 8

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	9,252	632	9,207	18,459	....	32.0
1	9,348	613	8,937	18,285	5.2	32.0
2	9,746	588	8,570	18,316	11.3	32.0
3	10,620	542	7,898	18,517	15.2	32.0
4	12,297	373	5,439	17,737	11.8	32.0
5	12,297	373	5,439	17,737	11.8	32.0

Rep unit 8 represents 5.8 percent of low-voltage dry-type distribution transformers units shipped, and 6.4 percent of shipments for equipment class 4 (three phase low-voltage dry-type).

TABLE V.23—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 8

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$ *
1	12	355
2	41	152

TABLE V.23—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 8—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
3	57	−58
4	31	722
5	31	722

* The savings represent the average LCC for affected consumers.
Rep unit 8 represents 5.8 percent of low-voltage dry-type distribution transformers units shipped, and 6.4 percent of shipments for equipment class 4 (three phase low-voltage dry-type).

Medium-Voltage Dry-Type Distribution Transformers

TABLE V.24—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 9

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	14,830	918	13,450	28,281	....	32.1
1	14,874	895	13,115	27,990	2.0	32.1
2	14,961	862	12,628	27,589	2.4	32.1
3	15,984	800	11,725	27,709	9.8	32.1
4	17,981	726	10,639	28,620	16.4	32.1
5	19,047	602	8,823	27,870	13.4	32.1

Rep unit 9 represents 7.3 percent of medium-voltage dry-type distribution transformers units shipped, and 77.0 percent of shipments for equipment class 6 (three phase medium-voltage dry-type, 20–45 kV BIL).

TABLE V.25—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 9

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	4	1,039
2	10	887
3	39	571
4	64	−339
5	49	410

* The savings represent the average LCC for affected consumers.
Rep unit 9 represents 7.3 percent of medium-voltage dry-type distribution transformers units shipped, and 77.0 percent of shipments for equipment class 6 (three phase medium-voltage dry-type, 20–45 kV BIL).

TABLE V.26—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 10

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	45,167	2,799	41,003	86,169	....	32.0
1	45,363	2,674	39,185	84,548	1.6	32.0
2	47,461	2,597	38,056	85,516	11.4	32.0
3	55,429	2,276	33,366	88,794	19.7	32.0
4	59,426	2,039	29,887	89,313	18.8	32.0
5	67,353	1,838	26,950	94,303	23.1	32.0

Rep unit 10 represents 2.2 percent of medium-voltage dry-type distribution transformers units shipped, and 23.0 percent of shipments for equipment class 6 (three phase medium-voltage dry-type, 20–45 kV BIL).

TABLE V.27—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 10

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	15	1,854
2	38	653
3	78	−2,625
4	81	−3,144
5	91	−8,133

* The savings represent the average LCC for affected consumers.
Rep unit 10 represents 2.2 percent of medium-voltage dry-type distribution transformers units shipped, and 23.0 percent of shipments for equipment class 6 (three phase medium-voltage dry-type, 20–45 kV BIL).

TABLE V.28—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 11

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	20,788	1,190	17,353	38,141	....	32.0
1	20,948	1,156	16,859	37,807	4.7	32.0
2	21,792	1,106	16,123	37,915	11.9	32.0
3	23,458	951	13,870	37,328	11.2	32.0
4	23,880	859	12,516	36,396	9.3	32.0
5	25,903	769	11,216	37,119	12.2	32.0

Rep unit 11 represents 2.6 percent of medium-voltage dry-type distribution transformers units shipped, and 6.6 percent of shipments for equipment class 8 (three phase medium-voltage dry-type, 45–95 kV BIL).

TABLE V.29—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 11

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	26	438
2	46	226
3	35	813
4	15	1,744
5	38	1,021

* The savings represent the average LCC for affected consumers.
Rep unit 11 represents 2.6 percent of medium-voltage dry-type distribution transformers units shipped, and 6.6 percent of shipments for equipment class 8 (three phase medium-voltage dry-type, 45–95 kV BIL).

TABLE V.30—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 12

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	54,830	3,290	47,795	102,625	....	32.0
1	52,818	3,138	45,595	98,413	0.0	32.0
2	55,069	3,063	44,505	99,574	1.1	32.0
3	63,490	2,659	38,639	102,129	13.7	32.0
4	67,333	2,430	35,311	102,644	14.5	32.0
5	74,722	2,206	32,055	106,777	18.4	32.0

Rep unit 12 represents 36.0 percent of medium-voltage dry-type distribution transformers units shipped, and 92.6 percent of shipments for equipment class 8 (three phase medium-voltage dry-type, 45–95 kV BIL).

TABLE V.31—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 12

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	1	4,649
2	9	3,051
3	49	496

TABLE V.31—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 12—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
4	54	−19
5	80	−4,152

* The savings represent the average LCC for affected consumers.
Rep unit 12 represents 36.0 percent of medium-voltage dry-type distribution transformers units shipped, and 92.6 percent of shipments for equipment class 8 (three phase medium-voltage dry-type, 45–95 kV BIL).

TABLE V.32—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 18

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	85,302	9,986	145,749	231,051		32.2
1	103,468	6,764	98,728	202,196	5.6	32.2
2	113,456	6,493	94,798	208,254	8.1	32.2
3	134,347	5,429	79,221	213,567	10.8	32.2
4	137,299	5,289	77,183	214,481	11.1	32.2
5	153,330	4,864	71,007	224,338	13.3	32.2

Rep unit 18 represents 0.3 percent of medium-voltage dry-type distribution transformers units shipped, and 0.8 percent of shipments for equipment class 8 (three phase medium-voltage dry-type, 45–95 kV BIL).

TABLE V.33—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 18

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	5	28,855
2	12	22,797
3	24	17,483
4	26	16,570
5	44	6,713

* The savings represent the average LCC for affected consumers.
Rep unit 18 represents 0.3 percent of medium-voltage dry-type distribution transformers units shipped, and 0.8 percent of shipments for equipment class 8 (three phase medium-voltage dry-type, 45–95 kV BIL).

TABLE V.34—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 13

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	24,894	1,316	19,168	44,062		31.9
1	25,304	1,256	18,292	43,597	6.8	31.9
2	26,181	1,212	17,653	43,835	12.4	31.9
3	28,454	1,111	16,176	44,630	17.3	31.9
4	31,436	986	14,364	45,801	19.8	31.9
5	31,983	936	13,636	45,619	18.7	31.9

Rep unit 13 represents 1.8 percent of medium-voltage dry-type distribution transformers units shipped, and 7.6 percent of shipments for equipment class 10 (three phase medium-voltage dry-type, ≥96 kV BIL).

TABLE V.35—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 13

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	24	515
2	44	228
3	72	−568
4	81	−1,739

TABLE V.35—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 13—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
5	80	−1,557

* The savings represent the average LCC for affected consumers.
Rep unit 13 represents 1.8 percent of medium-voltage dry-type distribution transformers units shipped, and 7.6 percent of shipments for equipment class 10 (three phase medium-voltage dry-type, ≥96 kV BIL).

TABLE V.36—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 14

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	63,684	4,386	63,615	127,299		32.0
1	66,945	4,263	61,834	128,779	26.6	32.0
2	70,089	4,140	60,066	130,155	26.1	32.0
3	80,939	3,629	52,588	133,527	22.8	32.0
4	85,714	3,281	47,555	133,268	19.9	32.0
5	93,684	3,027	43,893	137,577	22.1	32.0

Rep unit 14 represents 22.1 percent of medium-voltage dry-type distribution transformers units shipped, and 91.5 percent of shipments for equipment class 10 (three phase medium-voltage dry-type, ≥96 kV BIL).

TABLE V.37—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 14

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021$) *
1	88	−1,480
2	87	−2,856
3	78	−6,228
4	82	−5,969
5	93	−10,278

* The savings represent the average LCC for affected consumers.
Rep unit 14 represents 22.1 percent of medium-voltage dry-type distribution transformers units shipped, and 91.5 percent of shipments for equipment class 10 (three phase medium-voltage dry-type, ≥96 kV BIL).

TABLE V.38—AVERAGE LCC AND PBP RESULTS FOR REPRESENTATIVE UNIT 19

Standard level	Average costs (2021$)				Simple payback period (years)	Average lifetime (years)
	Installed cost	First year's operating cost	Lifetime operating cost	LCC		
0	88,951	9,349	136,177	225,128		31.9
1	107,573	7,209	105,019	212,591	8.7	31.9
2	117,299	6,845	99,747	217,046	11.3	31.9
3	137,304	5,717	83,212	220,516	13.3	31.9
4	142,539	5,455	79,409	221,948	13.8	31.9
5	154,646	5,105	74,341	228,988	15.5	31.9

Rep unit 19 represents 0.2 percent of medium-voltage dry-type distribution transformers units shipped, and 0.8 percent of shipments for equipment class 10 (three phase medium-voltage dry-type, ≥96 kV BIL).

TABLE V.39—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 19

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
1	16	12,536
2	38	8,082
3	43	4,611
4	47	3,180

TABLE V.39—LCC SAVINGS RELATIVE TO THE BASE CASE EFFICIENCY DISTRIBUTION FOR REPRESENTATIVE UNIT 19—Continued

Standard level	% Consumers with net cost	Average savings—impacted consumers (2021)$ *
5	63	−3,860

* The savings represent the average LCC for affected consumers.
Rep unit 19 represents 0.2 percent of medium-voltage dry-type distribution transformers units shipped, and 0.8 percent of shipments for equipment class 10 (three phase medium-voltage dry-type, ≥96 kV BIL).

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. Table V.40 compares the average LCC savings and PBP at each efficiency level for the consumer subgroups with similar metrics for the entire consumer sample for equipment classes 1 and 2. Chapter 11 of the NOPR TSD presents the complete LCC and PBP results for the subgroups.

Utilities Serving Low Population Densities

TABLE V.40—COMPARISON OF LCC SAVINGS AND PBP FOR UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 1

TSL	All utilities	Serving low population densities
Average LCC Savings (2021$)		
1	−53	−55
2	−114	−112
3	0	90
4	72	178
5	−599	−497
Payback Period (years)		
1	78.6	120.6
2	69.2	86.0
3	19.3	19.0
4	16.2	15.8
5	40.5	42.2
Consumers with Net Cost (%)		
1	69	66
2	86	82
3	47	33
4	34	20
5	96	92

Rep unit 1 represents 20.3 percent of liquid-immersed distribution transformers units shipped, and 21.8 percent of shipments for equipment class 1 (single phase liquid-immersed).

TABLE V.41—COMPARISON OF LCC SAVINGS AND PBP FOR UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 2

TSL	All utilities	Serving low population densities
Average LCC Savings (2021$)		
1	146	189
2	201	267
3	186	253
4	131	199
5	−176	−107
Payback Period (years)		
1	0.0	0.0
2	0.4	0.3
3	4.1	3.9
4	10.1	9.9
5	29.3	30.2

TABLE V.41—COMPARISON OF LCC SAVINGS AND PBP FOR UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 2—Continued

TSL	All utilities	Serving low population densities
Consumers with Net Cost (%)		
1	22	21
2	10	7
3	9	7
4	13	10
5	84	72

Rep unit 2 represents 72.7 percent of liquid-immersed distribution transformers units shipped, and 78.0 percent of shipments for equipment class 1 (single phase liquid-immersed).

TABLE V.42—COMPARISON OF LCC SAVINGS AND PBP FOR UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 3

TSL	All utilities	Serving low population densities
Average LCC Savings (2021$)		
1	1,121	1,798
2	1,312	2,044
3	1,216	1,962
4	1,029	1,772
5	−414	308
Payback Period (years)		
1	5.9	5.3
2	5.6	5.1
3	8.4	7.8
4	12.3	11.9
5	21.8	22.3
Consumers with Net Cost (%)		
1	28	22
2	22	16
3	23	16
4	23	15
5	65	44

Rep unit 3 represents 0.2 percent of liquid-immersed distribution transformers units shipped, and 0.2 percent of shipments for equipment class 1 (single phase liquid-immersed).

TABLE V.43—COMPARISON OF LCC SAVINGS AND PBP UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 4

TSL	All utilities	Serving low population densities
Average LCC Savings (2021$)		
1	−26	−12
2	−55	−9
3	381	629
4	511	802
5	77	372
Payback Period (years)		
1	26.9	28.0
2	24.4	24.4
3	13.2	13.1
4	12.0	11.9
5	18.7	19.1
Consumers with Net Cost (%)		
1	38	37
2	67	58
3	25	21

TABLE V.43—COMPARISON OF LCC SAVINGS AND PBP UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 4—Continued

TSL	All utilities	Serving low population densities
4	13	9
5	49	32

Rep unit 4 represents 4.6 percent of liquid-immersed distribution transformers units shipped, and 68.0 percent of shipments for equipment class 2 (three phase liquid-immersed).

TABLE V.44—COMPARISON OF LCC SAVINGS AND PBP FOR UTILITIES SERVING LOW POPULATION DENSITIES SUBGROUP AND ALL UTILITIES; REPRESENTATIVE UNIT 5

TSL	All utilities	Serving low population densities
Average LCC Savings (2021$)		
1	986	1,498
2	2,095	2,876
3	1,888	2,839
4	1,543	2,830
5	−7,913	−5,881
Payback Period (years)		
1	11.0	10.1
2	8.0	7.1
3	11.0	9.9
4	14.2	13.8
5	35.8	37.3
Consumers with Net Cost (%)		
1	41	38
2	27	23
3	29	24
4	29	19
5	96	89

Rep unit 5 represents 2.1 percent of liquid-immersed distribution transformers units shipped, and 31.5 percent of shipments for equipment class 2 (three phase liquid-immersed).

Utilities That Deploy Distribution Transformers in Vaults or Other Space Constrained Areas

As noted in section IV.C.1, for this NOPR DOE considered submersible distribution transformers and their associated vault, or space constrained installation costs with individual representative units, 15 and 16. The consumer results for these equipment are presented in Table V.12 through Table V.15.

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 payback period for each of the considered standard level, DOE used discrete values, and as required by EPCA, based the energy use calculation on the DOE test procedure for distribution transformers. In contrast, the PBPs presented in section V.B.1.a were calculated using distributions that reflect the range of energy use in the field.

Table V.45 presents the rebuttable-presumption payback periods for the considered standard level for distribution transformers. While DOE examined the rebuttable-presumption criterion, it considered whether the standard levels considered for the NOPR 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.45—REBUTTABLE-PRESUMPTION PAYBACK PERIODS

EC	RU	Trial standard level				
		1	2	3	4	5
1	1	15.9	19.9	25.3	22.1	25.7
1	2	0.1	6.4	9.3	12.1	19.7
1	3	0	0	74.6	19.1	17.9

TABLE V.45—REBUTTABLE-PRESUMPTION PAYBACK PERIODS—Continued

EC	RU	Trial standard level				
		1	2	3	4	5
2	4	11.2	22.9	14.2	13.2	14.1
2	5	0	0	0	21.1	26.1
2	17	8.4	9.7	10.3	10.0	14.6
3	6	0	2.3	4.3	8.7	8.7
4	7	0	0	3.8	8.1	6.9
6	8	5.6	8.1	9.7	10.6	10.6
6	9	1.3	1.4	4.6	7.9	9.7
8	10	1.4	6.6	18.4	15.4	16.0
8	11	1.4	4.9	8.9	8.7	8.7
8	18	4.6	5.8	9.7	9.6	10.2
10	12	0	0.6	63.2	18.2	15.4
10	13	5.5	10.2	12.5	43.4	25.3
10	14	21.4	11.4	−67.7	39.4	24.4
10	19	5.6	6.5	12.7	12.0	12.0
12	15	n.a.	n.a.	n.a.	n.a.	14.1
12	16	n.a.	n.a.	n.a.	n.a.	26.2

2. Economic Impacts on Manufacturers

DOE performed an MIA to estimate the impact of amended energy conservation standards on manufacturers of distribution transformers. The following section describes the expected impacts on manufacturers at each considered TSL. Chapter 12 of the NOPR 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 a standard. 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 type of distribution transformer manufacturers: 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 percentage scenario and (2) the preservation of operating profit scenario. In the preservation of gross margin percentage 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 [102] is applied across all efficiency levels. 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 potential 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 type of distribution transformer manufacturers. 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 2022 through 2056. 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.46 and Table V.47; the range in INPV for LVDT distribution transformer manufacturers in Table V.48 and Table V.49; and the range in INPV for MVDT distribution transformer manufacturers in Table V.50 and Table V.51.

Liquid-Immersed Distribution Transformers

TABLE V.46—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE SCENARIO

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
INPV	*2021$ millions*	1,384	1,297	1,268	1,232	1,233	1,347
Change in INPV	*2021$ millions*		(87.1)	(116.5)	(152.1)	(151.0)	(37.2)
	%		(6.3)	(8.4)	(11.0)	(10.9)	(2.7)
Product Conversion Costs	*2021$ millions*		72.0	82.5	99.1	102.0	102.9
Capital Conversion Costs	*2021$ millions*		56.6	92.6	150.3	168.5	186.6

[102] The gross margin percentage of 20 percent is based on a manufacturer markup of 1.25.

TABLE V.46—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE SCENARIO—Continued

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
Total Conversion Costs	2021$ millions		128.6	175.2	249.4	270.6	289.4

* Numbers in parentheses "( )" are negative. Some numbers might not round due to rounding.

TABLE V.47—MANUFACTURER IMPACT ANALYSIS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT SCENARIO

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
INPV	2021$ millions	1,384	1,283	1,242	1,166	1,133	1,004
Change in INPV	2021$ millions		(101.1)	(142.1)	(218.3)	(251.3)	(380.7)
	%		(7.3)	(10.3)	(15.8)	(18.1)	(27.5)
Product Conversion Costs	2021$ millions		72.0	82.5	99.1	102.0	102.9
Capital Conversion Costs	2021$ millions		56.6	92.6	150.3	168.5	186.6
Total Conversion Costs	2021$ millions		128.6	175.2	249.4	270.6	289.4

* Numbers in parentheses "( )" are negative. Some numbers might not round due to rounding.

At TSL 1, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$101.1 million to −$87.1 million, corresponding to a change in INPV of −7.3 percent to −6.3 percent. At TSL 1, industry free cash flow is estimated to decrease by approximately 56.0 percent to $40.2 million, compared to the no-new-standard case value of $91.2 million in 2026, the year before the estimated compliance date.

TSL 1 would set the energy conservation standard at EL 1 for all liquid-immersed distribution transformers except for submersible liquid-immersed transformers (Equipment Class 12, Rep. Unit 15 and 16), which would remain at baseline. DOE estimates that approximately 4.3 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $72.0 million in product conversion costs to redesign transformers and approximately $56.6 million in capital conversion costs as some liquid-immersed distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 1, the shipment-weighted average MPC for liquid-immersed distribution transformers increases by 0.6 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. In the gross margin percentage scenario, manufacturers can fully pass on this slight cost increase to customers. The slight increase in shipment-weighted average MPC is outweighed by the $128.6 million in conversion costs, causing a negative change in INPV at TSL 1 under the preservation of gross margin percentage 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 higher MPCs. In this scenario, the 0.6 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $128.6 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 1 under the preservation of operating profit scenario.

At TSL 2, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$142.1 million to −$116.5 million, corresponding to a change in INPV of −10.3 percent to −8.4 percent. At TSL 2, industry free cash flow is estimated to decrease by approximately 77.8 percent to $20.2 million, compared to the no-new-standard case value of $91.2 million in 2026, the year before the estimated compliance date.

TSL 2 would set the energy conservation standard at EL 2 for all liquid-immersed distribution transformers except for submersible liquid-immersed transformers (Equipment Class 12, Rep. Unit 15 and 16), which would remain at baseline. DOE estimates that approximately 1.4 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $82.5 million in product conversion costs to redesign transformers and approximately $92.6 million in capital conversion costs as many liquid-immersed distribution transformer cores manufactured are expected to use amorphous steel.

At TSL 2, the shipment-weighted average MPC for liquid-immersed distribution transformers increases by 1.7 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The increase in shipment-weighted average MPC is outweighed by the $175.2 million in conversion costs, causing a negative change in INPV at TSL 2 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 1.7 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $175.2 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 2 under the preservation of operating profit scenario.

At TSL 3, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$218.3 million to −$152.1 million, corresponding to a change in INPV of −15.8 percent to

−11.0 percent. At TSL 3, industry free cash flow is estimated to decrease by approximately 112.8 percent to −$11.6 million, compared to the no-new-standard case value of $91.2 million in 2026, the year before the estimated compliance date.

TSL 3 would set the energy conservation standard at EL 3 for all liquid-immersed distribution transformers except for submersible liquid-immersed transformers (Equipment Class 12, Rep. Unit 15 and 16), which would remain at baseline. DOE estimates that approximately 0.9 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $99.1 million in product conversion costs to redesign transformers and approximately $150.3 million in capital conversion costs as most 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 5.6 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The moderate increase in shipment-weighted average MPC is outweighed by the $249.4 million in conversion costs, causing a negative change in INPV at TSL 3 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 5.6 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $249.4 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 3 under the preservation of operating profit scenario.

At TSL 4, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$251.3 million to −$151.0 million, corresponding to a change in INPV of −18.1 percent to −10.9 percent. At TSL 4, industry free cash flow is estimated to decrease by approximately 122.9 percent to −$20.9 million, compared to the no-new-standard case value of $91.2 million in 2026, the year before the estimated compliance date.

TSL 4 would set the energy conservation standard at EL 4 for all liquid-immersed distribution transformers except for submersible liquid-immersed transformers (Equipment Class 12, Rep. Unit 15 and 16), which would remain at baseline. DOE estimates that approximately 0.7 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $102.0 million in product conversion costs to redesign transformers and approximately $168.5 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 8.9 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The moderate increase in shipment-weighted average MPC is outweighed by the $270.6 million in conversion costs, causing a negative change in INPV at TSL 4 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 8.9 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $270.6 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 4 under the preservation of operating profit scenario.

At TSL 5, DOE estimates the impacts on INPV for liquid-immersed distribution transformer manufacturers to range from −$380.7 million to −$37.2 million, corresponding to a change in INPV of −27.5 percent to −2.7 percent. At TSL 5, industry free cash flow is estimated to decrease by approximately 132.1 percent to −$29.3 million, compared to the no-new-standard case value of $91.2 million in 2026, the year before the estimated compliance date.

TSL 5 would set the energy conservation standard at EL 5, max-tech, for all liquid-immersed distribution transformers. DOE estimates that approximately 0.2 percent of shipments would meet these energy conservation standards in the no-new-standards case in 2027. DOE estimates liquid-immersed distribution transformer manufacturers would spend approximately $102.9 million in product conversion costs to redesign transformers and approximately $186.6 million in capital conversion costs as almost 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 increases by 33.3 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The significant increase in shipment-weighted average MPC is outweighed by the $289.4 million in conversion costs, causing a negative change in INPV at TSL 5 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 33.3 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $289.4 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 5 under the preservation of operating profit scenario.

Low-Voltage Dry-Type Distribution Transformers

TABLE V.48—MANUFACTURER IMPACT ANALYSIS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE SCENARIO

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
INPV	*2021$ millions*	194	189	189	177	168	161
Change in INPV	*2021$ millions*		(5.4)	(4.9)	(16.9)	(26.3)	(33.5)
	%		(2.8)	(2.5)	(8.7)	(13.6)	(17.2)
Product Conversion Costs	*2021$ millions*		9.6	9.6	14.5	18.9	19.1
Capital Conversion Costs	*2021$ millions*		0.0	0.0	19.1	37.2	50.3

TABLE V.48—MANUFACTURER IMPACT ANALYSIS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE SCENARIO—Continued

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
Total Conversion Costs	2021$ millions		9.6	9.6	33.5	56.1	69.4

* Numbers in parentheses "( )" are negative. Some numbers might not round due to rounding.

TABLE V.49—MANUFACTURER IMPACT ANALYSIS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT SCENARIO

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
INPV	2021$ millions	194	189	188	167	145	133
Change in INPV	2021$ millions		(5.4)	(5.9)	(27.0)	(49.1)	(61.0)
	%		(2.8)	(3.0)	(13.9)	(25.3)	(31.4)
Product Conversion Costs	2021$ millions		9.6	9.6	14.5	18.9	19.1
Capital Conversion Costs	2021$ millions		0.0	0.0	19.1	37.2	50.3
Total Conversion Costs	2021$ millions		9.6	9.6	33.5	56.1	69.4

* Numbers in parentheses "( )" are negative. Some numbers might not round due to rounding.

At TSL 1, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to be approximately −$5.4 million, which corresponds to a change in INPV of –2.8 percent. At TSL 1, industry free cash flow is estimated to decrease by approximately 17.8 percent to $15.6 million, compared to the no-new-standard case value of $19.0 million in 2026, the year before the estimated compliance date.

TSL 1 would set the energy conservation standard at EL 1 for all LVDT distribution transformers. DOE estimates that approximately 22.7 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates LVDT distribution transformer manufacturers would spend approximately $9.6 million in product conversion costs to redesign transformers but would not have to make significant investments in capital conversion costs as no LVDT distribution transformer cores used are expected to use amorphous steel.

At TSL 1, the shipment-weighted average MPC for LVDT distribution transformers does not increases relative to the no-new-standards case shipment-weighted average MPC in 2027. The preservation of gross margin percentage scenario produces similar INPV results as the preservation of operating profit scenario due to the negligible change in MPC at TSL 1. The change in IPNV is driven exclusively by the $9.6 million in conversion costs, causing a negative change in INPV at TSL 1 under both scenarios.

At TSL 2, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$5.9 million to −$4.9 million, corresponding to a change in INPV of −2.8 percent to −2.5 percent. At TSL 2, industry free cash flow is estimated to decrease by approximately 17.8 percent to $15.6 million, compared to the no-new-standard case value of $19.0 million in 2026, the year before the estimated compliance date.

TSL 2 would set the energy conservation standard at EL 2 for all LVDT distribution transformers. DOE estimates that approximately 3.4 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates LVDT distribution transformer manufacturers would spend approximately $9.6 million in product conversion costs to redesign transformers but would not have to make significant investments in capital conversion costs as no LVDT distribution transformer cores used are expected to use amorphous steel.

At TSL 2, the shipment-weighted average MPC for LVDT distribution transformers increases by 0.8 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The increase in shipment-weighted average MPC is outweighed by the $9.6 million in conversion costs, causing a negative change in INPV at TSL 2 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 0.8 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $9.6 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 2 under the preservation of operating profit scenario.

At TSL 3, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$27.0 million to −$16.9 million, corresponding to a change in INPV of −13.9 percent to −8.7 percent. At TSL 3, industry free cash flow is estimated to decrease by approximately 72.1 percent to $5.3 million, compared to the no-new-standard case value of $19.0 million in 2026, the year before the estimated compliance date.

TSL 3 would set the energy conservation standard at EL 3 for all LVDT distribution transformers. DOE estimates that approximately 0.1 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates LVDT distribution transformer manufacturers would spend approximately $14.5 million in product conversion costs to redesign transformers and approximately $19.1 million in capital conversion costs as some LVDT distribution transformers cores manufactured are expected to use amorphous steel.

At TSL 3, the shipment-weighted average MPC for LVDT distribution transformers increases by 8.5 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The moderate increase in shipment-weighted average MPC is outweighed by the $33.5 million in conversion costs, causing a negative change in INPV at TSL 3 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 8.5 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $33.5 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 3 under the preservation of operating profit scenario.

At TSL 4, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$49.1 million to −$26.3 million, corresponding to a change in INPV of −25.3 percent to −13.6 percent. At TSL 4, industry free cash flow is estimated to decrease by approximately 123.2 percent to −$4.4 million, compared to the no-new-standard case value of $19.0 million in 2026, the year before the estimated 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 2027. DOE estimates LVDT distribution transformer manufacturers would spend approximately $18.9 million in product conversion costs to redesign all LVDT transformers and approximately $37.2 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 19.0 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The significant increase in shipment-weighted average MPC is outweighed by the $56.1 million in conversion costs, causing a negative change in INPV at TSL 4 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 19.0 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $56.1 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 4 under the preservation of operating profit scenario.

At TSL 5, DOE estimates the impacts on INPV for LVDT distribution transformer manufacturers to range from −$61.0 million to −$33.5 million, corresponding to a change in INPV of −31.4 percent to −17.2 percent. At TSL 5, industry free cash flow is estimated to decrease by approximately 154.4 percent to −$10.4 million, compared to the no-new-standard case value of $19.0 million in 2026, the year before the estimated 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 at TSL 5. DOE estimates LVDT distribution transformer manufacturers would spend approximately $19.1 million in product conversion costs to redesign all LVDT distribution transformers and approximately $37.2 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 23.0 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The significant increase in shipment-weighted average MPC is outweighed by the $69.4 million in conversion costs, causing a negative change in INPV at TSL 5 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 23.0 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $69.4 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 5 under the preservation of operating profit scenario.

Medium-Voltage Dry-Type Distribution Transformers

TABLE V.50—MANUFACTURER IMPACT ANALYSIS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF GROSS MARGIN PERCENTAGE MARKUP SCENARIO

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
INPV	*2021$ millions*	87	85	86	80	80	82
Change in INPV	*2021$ millions*		(1.8)	(0.8)	(7.7)	(6.8)	(5.2)
	%		(2.1)	(0.9)	(8.8)	(7.8)	(5.9)
Product Conversion Costs	*2021$ millions*		3.1	3.1	6.0	6.1	6.2
Capital Conversion Costs	*2021$ millions*		0.0	0.0	11.9	13.1	15.1
Total Conversion Costs	*2021$ millions*		3.1	3.1	17.9	19.2	21.2

* Numbers in parentheses “()” are negative. Some numbers might not round due to rounding.

TABLE V.51—MANUFACTURER IMPACT ANALYSIS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT SCENARIO

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
INPV	*2021$ millions*	87	85	85	71	69	65
Change in INPV	*2021$ millions*		(1.9)	(2.7)	(16.3)	(18.7)	(22.6)
	%		(2.1)	(3.0)	(18.7)	(21.4)	(25.9)
Product Conversion Costs	*2021$ millions*		3.1	3.1	6.0	6.1	6.2

TABLE V.51—MANUFACTURER IMPACT ANALYSIS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—PRESERVATION OF OPERATING PROFIT SCENARIO—Continued

	Units	No-new-standards case	Trial standard level				
			1	2	3	4	5
Capital Conversion Costs	*2021$ millions*		0.0	0.0	11.9	13.1	15.1
Total Conversion Costs	*2021$ millions*		3.1	3.1	17.9	19.2	21.2

* Numbers in parentheses "( )" are negative. Some numbers might not round due to rounding.

At TSL 1, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$1.9 million to −$1.8 million, which corresponds to a change in INPV of approximately –2.1 percent in both cases. At TSL 1, industry free cash flow is estimated to decrease by approximately 15.7 percent to $5.9 million, compared to the no-new-standard case value of $7.0 million in 2026, the year before the estimated compliance date.

TSL 1 would set the energy conservation standard at EL 1 for all MVDT distribution transformers. DOE estimates that approximately 21.2 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates MVDT distribution transformer manufacturers would spend approximately $3.1 million in product conversion costs to redesign transformers but would not have to make significant investments in capital conversion costs as no MVDT distribution transformer cores are expected to use amorphous steel.

At TSL 1, the shipment-weighted average MPC for MVDT distribution transformers does not increases relative to the no-new-standards case shipment-weighted average MPC in 2027. The preservation of gross margin percentage scenario produces similar INPV results as the preservation of operating profit scenario due to the negligible change in MPC at TSL 1. The change in INPV is almost exclusively driven by the $3.1 million in conversion costs, causing a negative change in INPV at TSL 1 under both scenarios.

At TSL 2, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$2.7 million to −$0.8 million, corresponding to a change in INPV of −3.0 percent to −0.9 percent. At TSL 2, industry free cash flow is estimated to decrease by approximately 15.7 percent to $5.9 million, compared to the no-new-standard case value of $7.0 million in 2026, the year before the estimated compliance date.

TSL 2 would set the energy conservation standard at EL 2 for all MVDT distribution transformers. DOE estimates that approximately 4.2 percent of shipments would meet or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates MVDT distribution transformer manufacturers would spend approximately $3.1 million in product conversion costs to redesign transformers but would not have to make significant investments in capital conversion costs as no MVDT distribution transformer cores are expected to use amorphous 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 2027. The increase in shipment-weighted average MPC is outweighed by the $3.1 million in conversion costs, causing a negative change in INPV at TSL 2 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 3.2 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $3.1 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 2 under the preservation of operating profit scenario.

At TSL 3, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$16.3 million to −$7.7 million, corresponding to a change in INPV of −18.7 percent to −8.8 percent. At TSL 3, industry free cash flow is estimated to decrease by approximately 107.1 percent to −$0.5 million, compared to the no-new-standard case value of $7.0 million in 2026, the year before the estimated 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 or exceed these energy conservation standards in the no-new-standards case in 2027. DOE estimates MVDT distribution transformer manufacturers would spend approximately $6.0 million in product conversion costs to redesign all MVDT distribution transformers and approximately $11.9 million in capital conversion costs as many 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 14.5 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The moderate increase in shipment-weighted average MPC is outweighed by the $17.9 million in conversion costs, causing a negative change in INPV at TSL 3 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 14.5 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $17.9 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 3 under the preservation of operating profit scenario.

At TSL 4, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$18.7 million to −$6.8 million, corresponding to a change in INPV of −21.4 percent to −7.8 percent. At TSL 4, industry free cash flow is estimated to decrease by approximately 115.3 percent to −$1.1 million, compared to the no-new-standard case value of $7.0 million in 2026, the year before the estimated 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 2027. DOE estimates MVDT distribution transformer manufacturers would spend approximately $6.1 million in product conversion costs to redesign all MVDT distribution transformers and approximately $13.1 million in capital conversion costs as most 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 20.0 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The significant increase in shipment-weighted average MPC is outweighed by the $19.2 million in conversion costs, causing a negative change in INPV at TSL 4 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 20.0 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $19.2 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 4 under the preservation of operating profit scenario.

At TSL 5, DOE estimates the impacts on INPV for MVDT distribution transformer manufacturers to range from −$22.6 million to −$5.2 million, corresponding to a change in INPV of –25.9 percent to −5.9 percent. At TSL 5, industry free cash flow is estimated to decrease by approximately 128.4 percent to −$2.0 million, compared to the no-new-standard case value of $7.0 million in 2026, the year before the estimated 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 at TSL 5. DOE estimates MVDT distribution transformer manufacturers would spend approximately $6.2 million in product conversion costs to redesign all MVDT distribution transformers and approximately $15.1 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 MVDT distribution transformers increases by 29.4 percent relative to the no-new-standards case shipment-weighted average MPC in 2027. The significant increase in shipment-weighted average MPC is outweighed by the $21.2 million in conversion costs, causing a negative change in INPV at TSL 5 under the preservation of gross margin percentage scenario.

Under the preservation of operating profit scenario, the 29.4 percent shipment-weighted average MPC increase results in a reduction in the margin after the analyzed compliance year. This reduction in the margin and the $21.2 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 5 under the preservation of operating profit scenario.

b. Direct Impacts on Employment

To quantitatively assess the potential impacts of amended energy conservation standards on direct employment in the distribution transformers 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 (TSLs) 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 2019 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.

Liquid-Immersed Distribution Transformers

TABLE V.52—DOMESTIC EMPLOYMENT FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS IN 2027

	No-new-standards case	Trial standard level				
		1	2	3	4	5
Domestic Production Workers in 2027	5,164	5,193	5,251	5,453	5,624	6,885
Domestic Non-Production Workers in 2027	1,830	1,840	1,861	1,932	1,993	2,440
Total Direct Employment in 2027	6,994	7,033	7,112	7,385	7,617	9,325
Potential Changes in Total Direct Employment in 2027		(874)–39	(1,180)–118	(1,506)–391	(1,549)–623	(1,549)–2,331

Using the estimated labor content from the GRIM combined with data from the 2019 ASM, DOE estimates that there would be approximately 5,164 domestic production workers, and 1,830 domestic non-production workers involved in liquid-immersed distribution transformer manufacturing in 2027 in the absence of amended energy conservation standards. Table V.52 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 Direct Employment in 2027'' displayed in Table V.52, 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 Direct Employment in 2027'' displayed in Table V.52, assumes that as more amorphous cores are used to meet higher energy conservation standards, either the amorphous core production is out-sourced 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 the energy conservation standard. 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.52 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.53—DOMESTIC EMPLOYMENT FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS IN 2027

	No-new-standards case	Trial standard level				
		1	2	3	4	5
Domestic Production Workers in 2027	169	169	170	183	201	208
Domestic Non-Production Workers in 2027	60	60	60	65	71	74
Total Direct Employment in 2027	229	229	230	248	272	282
Potential Changes in Total Direct Employment in 2027	....	0	0–1	(28)–19	(49)–43	(51)–53

Using the estimated labor content from the GRIM combined with data from the 2019 ASM, DOE estimates that there would be approximately 169 domestic production workers, and 60 domestic non-production workers involved in LVDT distribution transformer manufacturing in 2027 in the absence of amended energy conservation standards. Table V.53 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 Direct Employment in 2027'' displayed in Table V.53, assumes that all LVDT distribution transformer manufacturing remains in the U.S. The lower range of the ''Potential Change in Total Direct Employment in 2027'', 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.54—DOMESTIC EMPLOYMENT FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS IN 2027

	No-new-standards case	Trial standard level				
		1	2	3	4	5
Domestic Production Workers in 2027	275	275	284	315	330	356
Domestic Non-Production Workers in 2027	98	98	101	112	117	126
Total Direct Employment in 2027	373	373	385	427	447	482
Potential Changes in Total Direct Employment in 2027	....	0	0–12	(63)–54	(69)–74	(83)–109

Using the estimated labor content from the GRIM combined with data from the 2019 ASM, DOE estimates that there would be approximately 275 domestic production workers, and 98 domestic non-production workers involved in MVDT distribution transformer manufacturing in 2027 in the absence of amended energy conservation standards. Table V.54 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 Direct Employment in 2027'' displayed in Table V.54, assumes that all MVDT distribution transformer manufacturing remains in the U.S. The lower range of the ''Potential Change in Total Direct Employment in 2027'', 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.

DOE requests comment on the estimated potential domestic employment impacts on distribution transformer manufacturers presented in this NOPR.

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 IV.J.3.a, steel producers are shifting production away from GOES suited for distribution transformer core manufacturing to non-grain-oriented steels suited for electric vehicle production. However, amorphous steel has not seen the same significant increase in price as GOES since the beginning of 2021.

The availability of amorphous steel 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.

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 three-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 global supply of steel.

DOE requests comment on the potential availability of either amorphous steel, grain-oriented electrical steel, or any other materials that may be needed to meet any of the analyzed energy conservation standards in this rulemaking. More specifically, DOE requests comment on steel manufacturers' ability to increase supply of amorphous steel in reaction to increased demand for amorphous steel as a result of increased energy conservation standards for distribution transformers.

d. Impacts on Competition

EPCA directs DOE to consider any lessening of competition that is likely to result from imposition of standards. It further directs the Attorney General to determine the impacts, if any, of any lessening of competition. The competitive analysis includes an assessment of the impacts to smaller, yet significant, manufacturers. DOE bases its assessment on manufacturing cost data and on information collected from interviews with manufacturers. The manufacturer interviews focus on gathering information that would help in assessing asymmetrical cost increases to some manufacturers, increased proportion of fixed costs potentially increasing business risks, and potential barriers to market entry (*e.g.,* proprietary technologies).

As discussed in section IV.J.3, DOE interviewed a wide variety of distribution transformer manufacturers, including liquid-immersed distribution transformer manufacturers, LVDT distribution transformer manufacturers, MVDT distribution transformer manufacturers, small businesses, and steel suppliers. During these manufacturer interviews DOE asked manufacturers if energy conservation standards could result in a change in industry competition. Some manufacturers stated that there is a possibility that smaller manufacturers may exit the market or their market share may decrease, if these businesses are not able to make the investments to upgrade their production equipment or to create new equipment designs in order to comply with energy conservation standards. See section VI.B, for a complete discussion on the potential impacts to small businesses.

Based on the market and technology assessment conducted for this NOPR analysis, DOE identified 29 manufacturers of distribution transformers covered by this rulemaking. See chapter 3 of this NOPR TSD for a complete list of the distribution transformer manufacturers. The distribution transformer market has a handful of major manufacturers for each equipment type (*i.e.,* liquid-immersed, LVDT, MVDT). Transformer core sourcing is a major driver of transformer manufacturing strategy and competitiveness which may be impacted by the standards level. Typically, manufacturers with larger market shares produce most of their own cores and manufacturers with smaller market shares purchase the cores used in their distribution transformers. The Department does not believe the proposed standard will alter current core make-versus-buy decisions. The Department expects that manufacturers with larger market shares will make the large investments needed to convert their core production to amorphous steel. Manufacturers with smaller market shares that do not invest in amorphous core manufacturing will continue to have the option to source their cores. DOE does not anticipate a significant change in competition due to energy conservation standards as the business model and competitive position for most distribution transformer manufacturers will remain the same after compliance with energy conservation standards.

e. 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.

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 750 employees. The 750-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.

f. Cumulative Regulatory Burden

One aspect of assessing manufacturer burden involves looking at the cumulative impact of multiple DOE standards and the product-specific regulatory actions of other Federal agencies that affect the manufacturers of a covered product or equipment. While any one regulation may not impose a significant burden on manufacturers, the combined effects of several existing or impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency. DOE requests information regarding the impact of cumulative regulatory burden on manufacturers of distribution transformers associated with multiple DOE standards or product-specific regulatory actions of other Federal agencies.

DOE evaluates product-specific regulations that will take effect approximately 3 years before or after the estimated 2027 compliance date of any amended energy conservation standards for distribution transformers. This information is presented in Table V.55.

TABLE V.55—COMPLIANCE DATES AND EXPECTED CONVERSION EXPENSES OF FEDERAL ENERGY CONSERVATION STANDARDS AFFECTING DISTRIBUTION TRANSFORMER MANUFACTURERS

Federal energy conservation standard	Number of manufacturers *	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 (June 21, 2022)	5	1	2026	$46.2 (2020$)	2.8%

* 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.

In addition to the rulemaking listed in Table V.55, DOE has ongoing rulemakings for other products or equipment that distribution transformer manufacturers produce, including battery chargers; [103] external power supplies; [104] ceiling fan light kits; [105] electric motors; [106] residential conventional cooking products; [107] dishwashers; [108] dehumidifiers; [109] miscellaneous refrigeration products; [110] and residential clothes washers.[111] If DOE proposes or finalizes any energy conservation standards for these products or equipment prior to finalizing energy conservation standards for distribution transformers, DOE will include the energy conservation standards for these other products or equipment as part of the cumulative regulatory burden for the distribution transformers 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. Significance of 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

[103] *www.regulations.gov/docket/EERE-2008-BT-STD-0005.*

[104] *www.regulations.gov/docket/EERE-2020-BT-STD-0006.*

[105] *www.regulations.gov/docket/EERE-2019-BT-STD-0040.*

[106] *www.regulations.gov/docket/EERE-2020-BT-STD-0007.*

[107] *www.regulations.gov/docket/EERE-2014-BT-STD-0005.*

[108] *www.regulations.gov/docket/EERE-2019-BT-STD-0039.*

[109] *www.regulations.gov/docket/EERE-2019-BT-STD-0043.*

[110] *www.regulations.gov/docket/EERE-2020-BT-STD-0039.*

[111] *www.regulations.gov/docket/EERE-2017-BT-STD-0014.*

the 30-year period that begins in the first full year of anticipated compliance with amended standards (2027–2056). Table V.56 presents DOE's projections of the national energy savings for each TSL considered for distribution transformers, the results showing DOE's proposed standard are in bold. Savings are reported for each of the equipment classes as defined in Section IV.A.2. The savings were calculated using the approach described in section IV.H of this document.

TABLE V.56—CUMULATIVE NATIONAL ENERGY SOURCES FOR DISTRIBUTION TRANSFORMERS BY EQUIPMENT CLASS; 30 YEARS OF SHIPMENT, (2027–2056)

	Standard level				
	1	2	3	4	5
Primary Energy Savings (Quads)					
Liquid-Immersed:					
Equipment Class 1	2.16	3.16	4.45	**4.75**	4.89
Equipment Class 2	0.91	1.65	2.63	**2.97**	3.17
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	0.08
Liquid-Immersed Total	3.06	4.80	7.09	**7.72**	8.14
Low-Voltage Dry-Type:					
Equipment Class 3	0.02	0.03	0.05	0.09	**0.12**
Equipment Class 4	0.34	0.48	0.77	2.10	**2.25**
Low-Voltage Dry-Type Total	0.35	0.52	0.82	2.19	2.37
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	0.02	0.03
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.05	**0.07**	0.23	0.29	0.35
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.02	**0.04**	0.14	0.19	0.22
Medium-Voltage Dry-Type Total	0.08	**0.11**	0.39	0.51	0.61
FFC Energy Savings (Quads)					
Liquid-Immersed:					
Equipment Class 1	2.24	3.28	4.63	**4.94**	5.08
Equipment Class 2	0.94	1.71	2.73	**3.08**	3.29
Equipment Class 12	0.00	0.00	0.00	**0.00**	0.09
Liquid-Immersed Total	3.18	4.99	7.36	**8.02**	8.45
Low-Voltage Dry-Type:					
Equipment Class 3	0.02	0.03	0.05	0.09	**0.12**
Equipment Class 4	0.35	0.50	0.80	2.19	**2.34**
Low-Voltage Dry-Type Total	0.37	0.54	0.85	2.28	**2.47**
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	0.02	0.03
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.05	**0.07**	0.24	0.30	0.36
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.02	**0.04**	0.15	0.20	0.23
Medium-Voltage Dry-Type Total	0.08	**0.12**	0.40	0.53	0.63

OMB Circular A–4 [112] 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.[113] The review

[112] 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* (last accessed August 26, 2022).

[113] Section 325(m) of EPCA requires DOE to review its standards at least once every 6 years, and requires, for certain products, a 3-year period after any new standard is promulgated before compliance is required, except that in no case may any new standards be required within 6 years of the compliance date of the previous standards. While adding a 6-year review to the 3-year compliance

Continued

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.57. The impacts are counted over the lifetime of distribution transformers purchased in 2027–2036, the results showing DOE's proposed standard are in bold.

TABLE V.57—CUMULATIVE NATIONAL ENERGY SAVINGS FOR DISTRIBUTION TRANSFORMERS; 9 YEARS OF SHIPMENTS, (2027–2036)

	Standard level				
	1	2	3	4	5
Primary Energy Savings (Quads)					
Liquid-Immersed:					
Equipment Class 1	0.62	0.90	1.27	**1.36**	1.39
Equipment Class 2	0.26	0.47	0.75	**0.85**	0.90
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	0.02
Liquid-Immersed Total	0.87	1.37	2.02	**2.20**	2.32
Low-Voltage Dry-Type:					
Equipment Class 3	0.00	0.01	0.01	0.02	**0.03**
Equipment Class 4	0.10	0.14	0.22	0.60	**0.64**
Low-Voltage Dry-Type Total	0.10	0.15	0.23	0.63	**0.68**
Medium-Voltage Dry-Type:					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.00	**0.00**	0.00	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	0.08	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	0.02	**0.03**	0.11	0.14	0.17
FFC Energy Savings (Quads)					
Liquid-Immersed:					
Equipment Class 1	0.64	0.93	1.32	**1.41**	1.45
Equipment Class 2	0.27	0.49	0.78	**0.88**	0.94
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	0.03
Liquid-Immersed Total	0.91	1.42	2.10	**2.29**	2.41
Low-Voltage Dry-Type:					
Equipment Class 3	0.00	0.01	0.01	0.03	**0.04**
Equipment Class 4	0.10	0.14	0.23	0.62	**0.67**
Low-Voltage Dry-Type Total	0.11	0.15	0.24	0.65	**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**	0.00	0.01	0.01
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.02	**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	0.06	0.07
Medium-Voltage Dry-Type Total	0.02	**0.03**	0.12	0.15	0.18

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,[114] DOE calculated NPV using both a 7-percent and a 3-percent real discount rate. Table V.58 shows the consumer NPV results with impacts counted over the lifetime of products purchased in 2027–2056, the results showing DOE's proposed standard are in bold.

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.

[114] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *www.whitehouse.gov/omb/circulars_a004_a-4/* (last accessed April 15, 2022).

TABLE V.58—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR DISTRIBUTION TRANSFORMERS; 30 YEARS OF SHIPMENTS, BILLION 2021$, (2027–2056)

	Standard level				
	1	2	3	4	5
3 percent Discount Rate					
Liquid-Immersed:					
Equipment Class 1	2.55	3.34	4.00	**3.45**	−4.04
Equipment Class 2	0.43	0.81	1.50	**1.84**	−2.10
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	−0.10
Liquid-Immersed Total	2.98	4.15	5.50	**5.30**	−6.25
Low-Voltage Dry-Type:					
Equipment Class 3	0.07	0.13	0.15	0.31	**0.52**
Equipment Class 4	1.41	1.98	1.72	9.41	**9.11**
Low-Voltage Dry-Type Total	1.48	2.11	1.87	9.72	**9.63**
Medium-Voltage Dry-Type:					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.01
Equipment Class 6	0.01	**0.01**	0.02	0.02	0.04
Equipment Class 7	0.00	**0.00**	0.00	0.01	0.01
Equipment Class 8	0.25	**0.22**	0.76	0.77	0.54
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.00	**−0.02**	0.46	0.50	0.36
Medium-Voltage Dry-Type Total	0.26	**0.21**	1.25	1.30	0.96
7 percent Discount Rate					
Liquid-Immersed:					
Equipment Class 1	0.78	0.94	0.82	**0.24**	−4.41
Equipment Class 2	0.00	0.06	0.07	**0.01**	−2.60
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	−0.10
Liquid-Immersed Total	0.78	1.00	0.89	**0.26**	−7.11
Low-Voltage Dry-Type:					
Equipment Class 3	0.02	0.04	0.04	0.07	**0.13**
Equipment Class 4	0.50	0.70	0.35	2.72	**2.50**
Low-Voltage Dry-Type Total	0.53	0.74	0.39	2.79	**2.63**
Medium-Voltage Dry-Type:					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.10	**0.07**	0.18	0.15	0.01
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.01	**−0.04**	0.08	0.08	0.00
Medium-Voltage Dry-Type Total	0.09	**0.04**	0.27	0.23	0.00

The NPV results based on the aforementioned 9-year analytical period are presented in Table V.59. The impacts are counted over the lifetime of products purchased in 2027–2036. 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.59—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR DISTRIBUTION TRANSFORMERS; 9 YEARS OF SHIPMENTS, BILLION 2021$, (2027–2036)

	Standard level				
	1	2	3	4	5
3 percent Discount Rate					
Liquid-Immersed:					
Equipment Class 1	0.99	1.30	1.56	**1.36**	−1.50
Equipment Class 2	0.17	0.32	0.59	**0.73**	−0.78

TABLE V.59—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR DISTRIBUTION TRANSFORMERS; 9 YEARS OF SHIPMENTS, BILLION 2021$, (2027–2036)—Continued

	Standard level				
	1	2	3	4	5
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	−0.04
Liquid-Immersed Total	1.16	1.62	2.15	**2.09**	−2.32
Low-Voltage Dry-Type:					
Equipment Class 3	0.03	0.05	0.06	0.12	**0.20**
Equipment Class 4	0.55	0.77	0.68	3.69	**3.57**
Low-Voltage Dry-Type Total	0.58	0.82	0.74	3.81	**3.77**
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	0.02
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.10	**0.09**	0.30	0.30	0.22
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	0.00	**−0.01**	0.18	0.20	0.15
Medium-Voltage Dry-Type Total	0.10	**0.08**	0.49	0.51	0.39
7 percent Discount Rate					
Liquid-Immersed:					
Equipment Class 1	0.40	0.49	0.43	**0.14**	−2.24
Equipment Class 2	0.00	0.03	0.04	**0.02**	−1.32
Equipment Class 12	n.a.	n.a.	n.a.	n.a.	−0.05
Liquid-Immersed Total	0.41	0.52	0.48	0.15	−3.61
Low-Voltage Dry-Type:					
Equipment Class 3	0.01	0.02	0.02	0.04	**0.07**
Equipment Class 4	0.26	0.36	0.19	1.43	**1.32**
Low-Voltage Dry-Type Total	0.27	0.39	0.21	1.46	**1.38**
Medium-Voltage Dry-Type:					
Equipment Class 5	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 6	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 7	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 8	0.05	**0.04**	0.10	0.08	0.01
Equipment Class 9	0.00	**0.00**	0.00	0.00	0.00
Equipment Class 10	−0.01	**−0.02**	0.05	0.04	0.00
Medium-Voltage Dry-Type Total	0.04	**0.02**	0.14	0.12	0.01

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.F.1 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 NOPR 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

It is estimated that that amended energy conservation standards for distribution transformers would 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 (2027–2031), where these uncertainties are reduced.

The results suggest that the proposed standards would be 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 NOPR 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 tentatively concluded that the standards proposed in this NOPR would 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 proposed 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 part of this consideration, DOE weighed the effects on markets for both component parts (see IV.C.3.a) and distribution transformer equipment (see IV.A.6). DOE's preliminary finding is that this rule, if finalized as proposed, would not significantly affect competition in the market for distribution transformers. See section V.B.5 for a complete discussion on industry competition. As discussed in section III.E.1.e, the Attorney General determines the impact, if any, of any lessening of competition likely to result from a proposed standard, and transmits such determination in writing to the Secretary, together with an analysis of the nature and extent of such impact. To assist the Attorney General in making this determination, DOE has provided DOJ with copies of this NOPR and the accompanying TSD for review. DOE will consider DOJ's comments on the proposed rule in determining whether to proceed to a final rule. DOE will publish and respond to DOJ's comments in that document. DOE invites comment from the public regarding the competitive impacts that are likely to result from this proposed rule. In addition, stakeholders may also provide comments separately to DOJ regarding these potential impacts. See the **ADDRESSES** section for information to send comments to DOJ.

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 NOPR 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.60 through Table V.63 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. DOE reports annual emissions reductions for each TSL in chapter 13 of the NOPR TSD.

TABLE V.60—CUMULATIVE EMISSIONS REDUCTION FOR ALL DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056 AT PROPOSED STANDARD LEVELS

Power Sector Emissions	
CO_2 (*million metric tons*)	312.0
CH_4 (*thousand tons*)	21.3
N_2O (*thousand tons*)	2.9
NO_X (*thousand tons*)	146.0
SO_2 (*thousand tons*)	129.2
Hg (*tons*)	0.8
Upstream Emissions	
CO_2 (*million metric tons*)	25.5
CH_4 (*thousand tons*)	2419.9
N_2O (*thousand tons*)	0.1
NO_X (*thousand tons*)	386.9
SO_2 (*thousand tons*)	1.7
Hg (*tons*)	0.0
Total FFC Emissions	
CO_2 (*million metric tons*)	337.6
CH_4 (*thousand tons*)	2441.2
N_2O (*thousand tons*)	3.0
NO_X (*thousand tons*)	532.9
SO_2 (*thousand tons*)	130.9
Hg (*tons*)	0.9

Negative values refer to an increase in emissions.

TABLE V.61—CUMULATIVE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

	Trial standard level				
	1	2	3	4	5
Power Sector Emissions					
CO_2 (*million metric tons*)	94.2	147.8	217.7	**237.0**	249.4
CH_4 (*thousand tons*)	6.4	10.1	14.8	**16.2**	17.0
N_2O (*thousand tons*)	0.9	1.4	2.0	**2.2**	2.3
NO_X (*thousand tons*)	44.1	69.2	101.9	**110.9**	116.7
SO_2 (*thousand tons*)	39.1	61.4	90.5	**98.4**	103.5

TABLE V.61—CUMULATIVE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056—Continued

	Trial standard level				
	1	2	3	4	5
Hg (*tons*)	0.3	0.4	0.6	**0.6**	0.7
Upstream Emissions					
CO_2 (*million metric tons*)	7.7	12.0	17.7	**19.3**	20.3
CH_4 (*thousand tons*)	726.6	1139.8	1680.6	**1830.4**	1929.9
N_2O (*thousand tons*)	0.0	0.1	0.1	**0.1**	0.1
NO_X (*thousand tons*)	116.2	182.2	268.7	**292.7**	308.6
SO_2 (*thousand tons*)	0.5	0.8	1.2	**1.3**	1.3
Hg (*tons*)	0.0	0.0	0.0	**0.0**	0.0
Total FFC Emissions					
CO_2 (*million metric tons*)	101.9	159.8	235.4	**256.3**	269.7
CH_4 (*thousand tons*)	733.1	1149.8	1695.5	**1846.6**	1946.9
N_2O (*thousand tons*)	0.9	1.4	2.1	**2.3**	2.4
NO_X (*thousand tons*)	160.3	251.4	370.6	**403.6**	425.2
SO_2 (*thousand tons*)	39.7	62.2	91.6	**99.7**	104.8
Hg (*tons*)	0.3	0.4	0.6	**0.7**	0.7

Negative values refer to an increase in emissions.

TABLE V.62—CUMULATIVE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

	Trial standard level				
	1	2	3	4	5
Power Sector Emissions					
CO_2 (*million metric tons*)	10.7	15.6	24.8	66.1	**71.6**
CH_4 (*thousand tons*)	0.7	1.1	1.7	4.5	**4.9**
N_2O (*thousand tons*)	0.1	0.1	0.2	0.6	**0.7**
NO_X (*thousand tons*)	5.0	7.3	11.6	30.9	**33.5**
SO_2 (*thousand tons*)	4.4	6.4	10.2	27.1	**29.4**
Hg (*tons*)	0.0	0.0	0.1	0.2	**0.2**
Upstream Emissions					
CO_2 (*million metric tons*)	0.9	1.3	2.0	5.5	**5.9**
CH_4 (*thousand tons*)	84.0	122.4	194.5	519.1	**562.4**
N_2O (*thousand tons*)	0.0	0.0	0.0	0.0	**0.0**
NO_X (*thousand tons*)	13.4	19.6	31.1	83.0	**89.9**
SO_2 (*thousand tons*)	0.1	0.1	0.1	0.4	**0.4**
Hg (*tons*)	0.0	0.0	0.0	0.0	**0.0**
Total FFC Emissions					
CO_2 (*million metric tons*)	11.6	16.9	26.8	71.6	**77.6**
CH_4 (*thousand tons*)	84.8	123.4	196.2	523.5	**567.3**
N_2O (*thousand tons*)	0.1	0.2	0.2	0.6	**0.7**
NO_X (*thousand tons*)	18.4	26.9	42.7	113.9	**123.4**
SO_2 (*thousand tons*)	4.5	6.5	10.3	27.5	**29.8**
Hg (*tons*)	0.0	0.0	0.1	0.2	**0.2**

Negative values refer to an increase in emissions.

TABLE V.63—CUMULATIVE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

	Trial Standard Level				
	1	2	3	4	5
Power Sector Emissions					
CO_2 (*million metric tons*)	2.3	**3.4**	11.7	15.2	18.2
CH_4 (*thousand tons*)	0.2	**0.2**	0.8	1.0	1.2
N_2O (*thousand tons*)	0.0	**0.0**	0.1	0.1	0.2

TABLE V.63—CUMULATIVE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056—Continued

	Trial Standard Level				
	1	2	3	4	5
NO_X (*thousand tons*)	1.1	**1.6**	5.5	7.1	8.5
SO_2 (*thousand tons*)	1.0	**1.4**	4.8	6.2	7.5
Hg (*tons*)	0.0	**0.0**	0.0	0.0	0.0
Upstream Emissions					
CO_2 (*million metric tons*)	0.2	**0.3**	1.0	1.3	1.5
CH_4 (*thousand tons*)	18.4	**27.1**	92.3	120.0	143.7
N_2O (*thousand tons*)	0.0	**0.0**	0.0	0.0	0.0
NO_X (*thousand tons*)	2.9	**4.3**	14.8	19.2	23.0
SO_2 (*thousand tons*)	0.0	**0.0**	0.1	0.1	0.1
Hg (*tons*)	0.0	**0.0**	0.0	0.0	0.0
Total FFC Emissions					
CO_2 (*million metric tons*)	2.5	**3.7**	12.7	16.5	19.7
CH_4 (*thousand tons*)	18.6	**27.3**	93.1	121.1	144.9
N_2O (*thousand tons*)	0.0	**0.0**	0.1	0.1	0.2
NO_X (*thousand tons*)	4.0	**5.9**	20.2	26.3	31.5
SO_2 (*thousand tons*)	1.0	**1.4**	4.9	6.3	7.6
Hg (*tons*)	0.0	**0.0**	0.0	0.0	0.0

Negative values refer to an increase in emissions.

As part of the analysis for this rulemaking, 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 of this document discusses the SC–CO_2 values that DOE used. Table V.64 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 proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.64—PRESENT VALUE OF CO_2 EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

TSL	SC–CO_2 Case			
	Discount rate and statistics (million 2021$)			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
Liquid-immersed Distribution Transformers				
1	603.2	2,773.2	4,425.4	8,386.0
2	946.1	4,350.2	6,941.9	13,154.7
3	1,394.3	6,410.7	10,229.9	19,385.3
4	1,517.6	6,977.6	11,134.6	21,099.8
5	1,597.1	7,343.2	11,718.0	22,205.4
Low-voltage Dry Type Distribution Transformers				
1	72.9	333.0	530.3	1,007.4
2	106.1	484.8	772.1	1,466.7
3	168.6	770.4	1,227.0	2,330.8
4	450.3	2,056.9	3,276.0	6,223.1
5	487.9	2,228.8	3,549.8	6,743.2
Medium-voltage Distribution Transformers				
1	15.9	72.7	115.8	220.0
2	23.3	106.7	169.9	322.7
3	79.8	364.4	580.4	1,102.5
4	103.7	473.6	754.2	1,432.7
5	124.0	566.7	902.5	1,714.4

As discussed in section IV.L.2, 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.65 presents the value of the CH_4 emissions reduction at each TSL, and Table V.66 presents the value of the N_2O emissions reduction at each TSL. The time-series of annual values is presented for the proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.65—PRESENT VALUE OF METHANE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

TSL	SC–CH_4 Case			
	Discount rate and statistics (million 2021$)			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
Liquid-immersed Distribution Transformers				
1	202.8	659.9	939.6	1,748.1
2	318.1	1,035.0	1,473.7	2,741.9
3	469.0	1,526.2	2,173.0	4,042.9
4	510.8	1,662.2	2,366.7	4,403.2
5	538.6	1,752.5	2,495.3	4,642.6
Low-voltage Dry Type Distribution Transformers				
1	24.8	80.1	113.9	212.2
2	36.2	116.7	165.8	309.0
3	57.5	185.5	263.6	491.3
4	153.4	494.9	703.4	1,310.8
5	166.2	536.3	762.2	1,420.4
Medium-voltage Distribution Transformers				
1	5.4	17.6	25.0	46.6
2	8.0	25.8	36.7	68.3
3	27.3	88.0	125.1	233.2
4	35.5	114.5	162.7	303.1
5	42.4	137.0	194.7	362.8

TABLE V.66—PRESENT VALUE OF NITROUS OXIDE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

TSL	SC–N_2O Case			
	Discount rate and statistics (million 2021$)			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
Liquid-immersed Distribution Transformers				
1	2.1	9.2	14.5	24.5
2	3.4	14.4	22.7	38.5
3	4.9	21.2	33.5	56.7
4	5.4	23.1	36.5	61.7
5	5.7	24.3	38.4	64.9
Low-voltage Dry Type Distribution Transformers				
1	0.3	1.1	1.7	2.9
2	0.4	1.6	2.5	4.2
3	0.6	2.5	4.0	6.8
4	1.6	6.8	10.6	18.0
5	1.7	7.3	11.5	19.5
Medium-voltage Distribution Transformers				
1	0.1	0.2	0.4	0.6
2	0.1	0.4	0.6	0.9
3	0.3	1.2	1.9	3.2
4	0.4	1.6	2.4	4.2

TABLE V.66—PRESENT VALUE OF NITROUS OXIDE EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056—Continued

TSL	SC–N_2O Case			
	Discount rate and statistics (million 2021$)			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
5	0.4	1.9	2.9	5.0

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. Thus, any value placed on reduced GHG emissions in this proposed rulemaking is subject to change. That said, because of omitted damages, DOE agrees with the IWG that these estimates most likely underestimate the climate benefits of greenhouse gas reductions. 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 that the proposed standards would be economically justified even without inclusion of monetized benefits of reduced GHG emissions.

DOE also estimated the monetary value of the health 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.67 presents the present value for NO_X emissions reduction for each TSL calculated using 7-percent and 3-percent discount rates, and Table V.68 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 proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.67—PRESENT VALUE OF NO_X EMISSIONS REDUCTION FOR DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

TSL	3% Discount rate	7% Discount rate
	Million 2021$	Million 2021$
Liquid-Immersed Distribution Transformers		
1	1,385.3	4,631.4
2	2,172.9	7,264.6
3	3,203.1	10,709.0
4	3,487.6	11,660.1
5	3,674.0	12,283.6
Low-voltage Dry-Type Distribution Transformers		
1	171.4	552.0
2	249.5	803.7
3	396.6	1,277.5
4	1,058.5	3,409.6
5	1,147.0	3,694.6
Medium-voltage Dry-Type Distribution Transformers		
1	37.5	120.8
2	55.0	177.3
3	187.9	605.4
4	244.3	786.9
5	292.4	941.7

TABLE V.68—PRESENT VALUE OF SO_2 EMISSIONS REDUCTION DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056

TSL	3% Discount rate	7% Discount rate
	Million 2021$	Million 2021$
Liquid-immersed Distribution Transformers		
1	477.8	1,556.7
2	749.5	2,442.2

TABLE V.68—PRESENT VALUE OF SO_2 EMISSIONS REDUCTION DISTRIBUTION TRANSFORMERS SHIPPED IN 2027–2056—Continued

TSL	3% Discount rate	7% Discount rate
	Million 2021$	Million 2021$
3	1,104.1	3,597.5
4	1,201.2	3,913.9
5	1,262.4	4,113.2
Low-voltage Dry-Type Distribution Transformers		
1	57.8	181.3
2	84.2	263.9
3	133.8	419.3
4	357.3	1,119.8
5	387.1	1,213.4
Medium-voltage Dry-Type Distribution Transformers		
1	12.6	39.5
2	18.5	57.9
3	63.2	198.1
4	82.1	257.4
5	98.3	307.9

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)) No other factors were considered in this analysis.

8. Summary of Economic Impacts

Table V.69 presents the NPV values that result from adding the estimates of the potential 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 distribution transformers, and are measured for the lifetime of products shipped in 2027–2056. The 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 in 2027–2056. While many of the benefits from this proposed standard extend through 2115, the monetized benefits from GHG reductions are capped at end of 2070.

TABLE V.69—CONSUMER NPV COMBINED WITH PRESENT VALUE OF CLIMATE 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 2021$)					
5% Average SC–GHG case	10.0	15.1	21.7	22.9	12.3
3% Average SC–GHG case	12.6	19.3	27.8	29.5	19.3
2.5% Average SC–GHG case	14.5	22.3	32.2	34.4	24.4
3% 95th percentile SC–GHG case	19.3	29.8	43.3	46.4	37.1
7% discount rate for Consumer NPV and Health Benefits (billion 2021$)					
5% Average SC–GHG case	3.4	5.2	7.1	7.0	0.0
3% Average SC–GHG case	6.1	9.3	13.2	13.6	6.9
2.5% Average SC–GHG case	8.0	12.4	17.6	18.5	12.1
3% 95th percentile SC–GHG case	12.8	19.9	28.7	30.5	24.7
Low-voltage Distribution Transformers					
3% discount rate for Consumer NPV and Health Benefits (billion 2021$)					
5% Average SC–GHG case	2.3	3.3	3.8	14.9	15.2
3% Average SC–GHG case	2.6	3.8	4.5	16.8	17.3
2.5% Average SC–GHG case	2.9	4.1	5.1	18.2	18.9
3% 95th percentile SC–GHG case	3.4	5.0	6.4	21.8	22.7
7% discount rate for Consumer NPV and Health Benefits (billion 2021$)					
5% Average SC–GHG case	0.9	1.2	1.1	4.8	4.8
3% Average SC–GHG case	1.2	1.7	1.9	6.8	6.9

TABLE V.69—CONSUMER NPV COMBINED WITH PRESENT VALUE OF CLIMATE AND HEALTH BENEFITS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
2.5% Average SC–GHG case	1.4	2.0	2.4	8.2	8.5
3% 95th percentile SC–GHG case	2.0	2.9	3.7	11.8	12.3
Medium-voltage Distribution Transformers					
3% discount rate for Consumer NPV and Health Benefits (billion 2021$)					
5% Average SC–GHG case	0.4	0.5	2.2	2.5	2.4
3% Average SC–GHG case	0.5	0.6	2.5	2.9	2.9
2.5% Average SC–GHG case	0.6	0.7	2.8	3.3	3.3
3% 95th percentile SC–GHG case	0.7	0.8	3.4	4.1	4.3
7% discount rate for Consumer NPV and Health Benefits (billion 2021$)					
5% Average SC–GHG case	0.2	0.1	0.6	0.7	0.6
3% Average SC–GHG case	0.2	0.2	1.0	1.1	1.1
2.5% Average SC–GHG case	0.3	0.3	1.2	1.5	1.5
3% 95th percentile SC–GHG case	0.4	0.5	1.9	2.3	2.5

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. 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. 6295(o)(2)(B)(i)) The new or amended standard must also result in significant conservation of energy. (42 U.S.C. 6295(o)(3)(B))

For this NOPR, DOE considered the impacts of amended standards for each type of distribution transformer 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 for each type of equipment for 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) entrenched purchasing practices, (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, in the case of dry-type distribution transformers the purchaser is often not the operator of the equipment. Instead, they are often installed at the time of building construction and operated by tenants. In other circumstances where the owner is the operator, distribution transformers are often purchased based on lowest first cost (see section IV.F.3) rather than equipment efficiency. Having less than perfect foresight and a high degree of uncertainty about the future, consumers may trade off these types 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 Transformers Standards

Table V.70 and Table V.71 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 (2027–2056). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. The efficiency levels contained in each TSL are described in section V.A of this document. Table V.71 shows the consumer impacts as equipment classes, which are the shipment weighted average results of each equipment class's representative units. The consumer results for each representative unit and information on the fraction of shipments they represent are shown in section B.1.

TABLE V.70—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS TSLS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Cumulative FFC National Energy Savings					
Quads	3.22	5.06	7.43	**8.02**	8.45
Cumulative FFC Emissions Reduction					
CO_2 (*million metric tons*)	101.85	159.77	235.44	**256.27**	269.69
CH_4 (*thousand tons*)	733.07	1149.83	1695.46	**1846.56**	1946.92
N_2O (*thousand tons*)	0.92	1.45	2.14	**2.32**	2.44
NO_X (*thousand tons*)	160.27	251.40	370.62	**403.57**	425.24
SO_2 (*thousand tons*)	39.65	62.21	91.65	**99.71**	104.82
Hg (*tons*)	0.26	0.41	0.60	**0.65**	0.68
Present Value of Benefits and Costs (*3% discount rate, billion 2021$*)					
Consumer Operating Cost Savings	4.06	6.08	10.17	**12.77**	18.51
Climate Benefits *	3.44	5.40	7.96	**8.66**	9.12
Health Benefits **	6.19	9.71	14.31	**15.57**	16.40
Total Benefits †	13.70	21.19	32.43	**37.01**	44.03
Consumer Incremental Product Costs ‡	1.09	1.93	4.67	**7.48**	24.76
Consumer Net Benefits	2.98	4.15	5.50	**5.30**	−6.25
Total Net Benefits	12.61	19.26	27.76	**29.53**	19.27
Present Value of Benefits and Costs (*7% discount rate, billion 2021$*)					
Consumer Operating Cost Savings	1.36	2.04	3.40	**4.28**	6.20
Climate Benefits *	3.44	5.40	7.96	**8.66**	9.12
Health Benefits **	1.86	2.92	4.31	**4.69**	4.94
Total Benefits †	6.67	10.36	15.67	**17.63**	20.26
Consumer Incremental Product Costs ‡	0.58	1.04	2.51	**4.02**	13.31
Consumer Net Benefits	0.78	1.00	0.89	**0.26**	−7.11
Total Net Benefits	6.08	9.32	13.16	**13.61**	6.95

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the equipment shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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_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 consumer, climate, and health benefits. Total 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.69 for net benefits using all four SC–GHG estimates.

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

TABLE V.71—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS TSLS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1 *	TSL 2 *	TSL 3 *	TSL 4 *	TSL 5 *
Manufacturer Impacts					
Industry NPV (*million 2021$*) (No-new-standards case INPV = $1,384 million)	1,283 to 1,297	1,242 to 1,268	1,166 to 1,232	**1,133 to 1,233**	1,004 to 1,347
Industry NPV (*% change*)	(7.3) to (6.3)	(10.3) to (8.4)	(15.8) to (11.0)	**(18.1) to (10.9)**	(27.5) to (2.7)
Consumer Average LCC Savings (*2021$*)					
Equipment Class 1 *	105	135	147	**120**	(269)
Equipment Class 2 *	321	658	887	**868**	(2,493)
Equipment Class 12 *	n.a.	n.a.	n.a.	**n.a.**	(7,482)

TABLE V.71—SUMMARY OF ANALYTICAL RESULTS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS TSLS: MANUFACTURER AND CONSUMER IMPACTS—Continued

Category	TSL 1 *	TSL 2 *	TSL 3 *	TSL 4 *	TSL 5 *
Shipment-Weighted Average **	120	172	199	**172**	(425)
Consumer Simple PBP (*years*)					
Equipment Class 1	19.0	16.3	7.4	**11.4**	31.7
Equipment Class 2	20.8	18.7	12.1	**12.5**	24.6
Equipment Class 12	n.a.	n.a.	n.a.	**n.a.**	36.0
Shipment-Weighted Average **	19	16	8	**12**	31
Percent of Consumers that Experience a Net Cost					
Equipment Class 1	32	27	17	**18**	87
Equipment Class 2	39	54	26	**19**	64
Equipment Class 12	n.a.	n.a.	n.a.	**n.a.**	95
Shipment-Weighted Average **	28	21	21	**18**	70

Parentheses indicate negative (−) values. The entry "n.a." means not applicable because there is no change in the standard at certain TSLs.
* The equipment classes, shown here are the shipment weighted average results of each equipment class's representative units. The consumer results for each representative unit and information on the fraction of shipments they represent are shown in section B.1.
** Scaled across the representative capacities of each equipment class and weighted by shares of each equipment class in total projected shipments in 2022.

First, DOE considered TSL 5, which represents the max-tech efficiency levels. TSL 5 would save an estimated 8.45 quads of energy, an amount DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $−7.11 billion using a discount rate of 7 percent, and $−6.25 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 269.69 Mt of CO_2, 104.82 thousand tons of SO_2, 425.24 thousand tons of NO_X, 0.68 tons of Hg, 1946.92 thousand tons of CH_4, and 2.44 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 $9.12 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 5 is $4.94 billion using a 7-percent discount rate and $16.40 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 $6.95 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 5 is $19.27 billion.

At TSL 5, the average LCC impact ranges from $–269 for equipment class 1 to $–7,482 for equipment class 12. The median PBP ranges from 24.6 years for equipment class 2 to 36.0 for equipment class 12. The fraction of consumers experiencing a net LCC cost ranges from 64 percent for equipment class 2 to 95 percent for equipment class 12.

At TSL 5, the projected change in INPV ranges from a decrease of $380.7 million to a decrease of $37.2 million, which corresponds to a change in INPV of –27.5 percent and –2.7 percent, respectively. DOE estimates that industry must invest $289.4 million to comply with standards set at TSL 5.

The Secretary tentatively 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 payback period estimates that approach or exceed average lifetimes. NPVs are calculated for equipment shipped over the period of 2027 through 2056 (see section IV.H.3). Distribution transformers are durable equipment with a maximum lifetime estimated at 60 years (see section IV.F.8), accruing operating cost savings through 2115. When considered over this time period, the discounted value of the incremental equipment costs outweigh 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 transformer do not outweigh the negative impacts to consumers and manufacturers. Consequently, the Secretary has tentatively concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated 8.02 quads of energy, an amount DOE considers significant. Under TSL 4, the NPV of consumer benefit would be $0.26 billion using a discount rate of 7 percent, and $5.30 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 256.27 Mt of CO_2, 99.71 thousand tons of SO_2, 403.57 thousand tons of NO_X, 0.65 tons of Hg, 1,846.56 thousand tons of CH_4, and 2.32 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 $8.66 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 4 is $4.69 billion using a 7-percent discount rate and $15.57 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 $13.61 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $29.53 billion.

At TSL 4, the average LCC impact ranges from $120 for equipment class 1 to $868 for equipment class 2. The mean PBP ranges from 11.4 years for equipment class 1 to 12.5 years for equipment class 2, well below the average lifetime of 32 years. The fraction of consumers experiencing a net LCC cost ranges is 18 percent for equipment classes 1 and 2.

At TSL 4, the projected change in INPV ranges from a decrease of $251.3 million to a decrease of $151.0 million, which corresponds to decreases of 18.1 percent and 10.9 percent, respectively. DOE estimates that industry must invest $270.6 million to comply with standards set at TSL 4.

After considering the analysis and weighing the benefits and burdens, the Secretary has tentatively concluded that a standard set at TSL 4 for liquid-immersed 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 18 percent of liquid-immersed 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 4, 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 4 are economically justified even without weighing the estimated monetary value of emissions reductions. When those emissions reductions are included—representing $8.66 billion in climate benefits (associated with the average SC–GHG at a 3-percent discount rate), and $15.57 billion (using a 3-percent discount rate) or $4.69 billion (using a 7-percent discount rate) in health benefits—the rationale becomes stronger still.

The energy savings under TSL 4 are primarily achievable by using amorphous steel. Both global and domestic capacity of amorphous steel is greater than it was during the consideration of the April 2013 Standards Final Rule and global capacity of amorphous steel (estimated to be approximately 150,000–250,000 metric tons) is approximately equal to the U.S. demand for electrical steel in distribution transformer applications (estimated to be approximately 225,000 metric tons). Further, amorphous capacity grew in response to the April 2013 Standards Final Rule, although market demand did not necessarily grow in-kind. Further, amorphous steel manufacturers' response to the April 2013 Standards Final Rule demonstrates that amorphous capacity can be added quickly and would be added in response to an amended standard. Stakeholders have expressed willingness to increase supply to match any potential demand created by an amended efficiency standard. In the current market, increased capacity of amorphous steel is limited more by the demand for amorphous steel rather than any constraints on potential production capacity. Therefore, in the presence of an amended standard, it is expected that amorphous capacity would quickly rise to meet demand before the effective date of any amended energy conservation standards.

While there has historically been concern over the fact that there is only a single domestic supplier of amorphous steel, the GOES market is also served by a single domestic supplier. Stakeholders have noted that sufficient domestic supply of GOES is available only for M3 steel. Any efficiency standard that requires steel with lower no-load losses than M3 would not be able to be served entirely by a domestic source without further investment. The current market of electrical steel in distribution transformer applications is very much a global market at present.

Further, while some stakeholders have expressed concern as to whether amorphous supply would be sufficient to serve the entire market, stakeholders have also expressed supply concerns regarding GOES. Notably, stakeholders have identified increased competition for non-oriented electrical steel to serve the electric vehicle market. This competing demand is not expected to disappear in the near term and stakeholders have already seen supply challenges for many of the higher performing GOES grades. Amorphous steel has not been commercialized in electric motor applications and as such, does not experience the same competing demand for electric vehicle applications. The increased demand for non-oriented electrical steel also offers an alternative for current producers of GOES steel to transition their production to non-oriented electrical steel, meeting a needed market demand.

The consistent practice of distribution transformer customers to lightly-load their distribution transformers (see section IV.E.1.a), means that the majority of energy savings are associated with reducing no-load losses. While higher grades of GOES may have slightly improved no-load loss characteristics, amorphous steel tends to reduce no-load losses by over 60 percent. Meaning, even if the best performing grades of GOES were available in unlimited quantities, amorphous steel would still lead to significant energy savings. Further, by nature of DOE evaluating efficiency of liquid-immersed distribution transformers at 50 percent load, even if loading increases such that in-service RMS average PUL is 50 percent, the distribution transformers produced under the amended efficiency standard would be more efficient than minimally efficient transformers on the market today.

The transition from GOES cores to amorphous cores does require some amount of investment on the part of the distribution transformer manufacturer if they produce their own cores. While these costs are not trivial, the benefit to consumers vastly outweighs the cost to manufacturers. Further, the increased practice of outsourcing distribution transformer core production means that there is little burden on small businesses, who overwhelmingly purchase prefabricated distribution transformer cores, rather than producing them in-house. 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 proposed amended standard levels for distribution transformers by grouping the efficiency levels for each equipment class 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. For the ELs above baseline that compose TSL 4 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 4 to be 18 percent for all equipment classes.

For liquid-immersed distribution transformers (including single-phase and three-phase equipment) TSL 4 (*i.e.,* the proposed TSL) represents a 20 percent reduction in losses over the current standard, with the exception of submersible liquid-immersed distribution transformers (equipment class 12) which remain at baseline.

Therefore, based on the previous considerations, DOE proposes to adopt the energy conservation standards for liquid-immersed distribution transformers at TSL 4. The proposed amended energy conservation standards for distribution transformers, which are expressed as percentage efficiency at 50 percent PUL are shown in Table V.72.

TABLE V.72—PROPOSED AMENDED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS

Electrical efficiency by kVA and Equipment class							
Equipment class 1		Equipment class 2		Equipment class 12			
Single-phase		Three-phase		Single-phase submersible		Three-phase submersible	
kVA		kVA		kVA		kVA	
10	98.96	15	98.92	10	98.70	15	98.65
15	99.05	30	99.06	15	98.82	30	98.83
25	99.16	45	99.13	25	98.95	45	98.92
37.5	99.24	75	99.22	37.5	99.05	75	99.03
50	99.29	112.5	99.29	50	99.11	112.5	99.11
75	99.35	150	99.33	75	99.19	150	99.16
100	99.40	225	99.38	100	99.25	225	99.23
167	99.46	300	99.42	167	99.33	300	99.27
250	99.51	500	99.48	250	99.39	500	99.35
333	99.54	750	99.52	333	99.43	750	99.40
500	99.59	1,000	99.54	500	99.49	1,000	99.43
667	99.62	1,500	99.58	667	99.52	1,500	99.48
833	99.64	2,000	99.61	833	99.55	2,000	99.51
		2,500	99.62			2,500	99.53
		3,750	99.66				
		5,000	99.68				

2. Benefits and Burdens of TSLs Considered for Low-Voltage Dry-Type Distribution Transformers Standards

Table V.73 and Table V.74 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 (2027–2056). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. The efficiency levels contained in each TSL are described in section V.A of this document. Table V.74 shows the consumer impacts as Equipment classes, which are the shipment weighted average results of each Equipment class's representative units. The consumer results for each representative unit and information on the fraction of shipments they represent are shown in section B.1.

TABLE V.73—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS TSLS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Cumulative FFC National Energy Savings					
Quads	0.37	0.54	0.85	2.28	2.47
Cumulative FFC Emissions Reduction					
CO_2 (*million metric tons*)	11.59	16.87	26.81	71.58	77.57
CH_4 (*thousand tons*)	84.76	123.42	196.22	523.53	567.30
N_2O (*thousand tons*)	0.10	0.15	0.24	0.64	0.70
NO_X (*thousand tons*)	18.44	26.85	42.69	113.91	123.44
SO_2 (*thousand tons*)	4.45	6.48	10.30	27.51	29.81
Hg (*tons*)	0.03	0.04	0.07	0.18	0.19
Present Value of Benefits and Costs (3% discount rate, billion 2021$)					
Consumer Operating Cost Savings	1.42	2.07	3.26	12.88	13.45
Climate Benefits *	0.41	0.60	0.96	2.56	2.77
Health Benefits **	0.73	1.07	1.70	4.53	4.91
Total Benefits †	2.57	3.74	5.92	19.97	21.13
Consumer Incremental Product Costs ‡	−0.06	−0.03	1.39	3.16	3.82
Consumer Net Benefits	1.48	2.11	1.87	9.72	9.63

TABLE V.73—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS TSLS: NATIONAL IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Total Net Benefits	2.63	3.78	4.52	16.81	17.31
Present Value of Benefits and Costs (7% discount rate, billion 2021$)					
Consumer Operating Cost Savings	0.50	0.72	1.14	4.49	4.69
Climate Benefits *	0.41	0.60	0.96	2.56	2.77
Health Benefits **	0.23	0.33	0.53	1.42	1.53
Total Benefits †	1.14	1.66	2.63	8.46	8.99
Consumer Incremental Product Costs ‡	−0.03	−0.02	0.75	1.70	2.05
Consumer Net Benefits	0.53	0.74	0.39	2.79	2.63
Total Net Benefits	1.17	1.68	1.88	6.77	6.94

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the equipment shipped in 2027–2056.

* Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO2), methane (SC–CH4), and nitrous oxide (SC–N2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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_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 consumer, climate, and health benefits. Total 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.69 for net benefits using all four SC–GHG estimates.

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

TABLE V.74—SUMMARY OF ANALYTICAL RESULTS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS TSLS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1 *	TSL 2 *	TSL 3 *	TSL 4 *	TSL 5 *
Manufacturer Impacts					
Industry NPV (million 2021$) (No-new-standards case INPV = $194 million	189	188 to 189	167 to 177	145 to 168	**133 to 161**
Industry NPV (*% change*)	(2.8)	(3.0) to (2.5)	(13.9) to (8.7)	(25.3) to (13.6)	**(31.4) to (17.2)**
Consumer Average LCC Savings (2021$)					
Equipment Class 3 *	312	203	146	108	**147**
Equipment Class 4 *	357	381	214	624	**574**
Shipment-Weighted Average **	311	315	179	492	**459**
Consumer Simple PBP (years)					
Equipment Class 3 *	0.0	3.3	7.6	11.7	**11.7**
Equipment Class 4 *	0.3	0.7	8.6	7.8	**9.1**
Shipment-Weighted Average **	0.3	1.0	7.6	7.4	**8.4**
Percent of Consumers that Experience a Net Cost					
Equipment Class 3 *	1	17	33	43	**40**
Equipment Class 4 *	8	9	30	10	**16**
Shipment-Weighted Average **	7	9	27	13	**17**

Parentheses indicate negative (−) values. The entry ''n.a.'' means not applicable because there is no change in the standard at certain TSLs.

* The equipment classes, shown here are the shipment weighted average results of each equipment class's representative units. The consumer results for each representative unit and information on the fraction of shipments they represent are shown in section B.1.

** Scaled across the representative capacities of each equipment class and weighted by shares of each equipment class in total projected shipments in 2022

First, DOE considered TSL 5, which represents the max-tech efficiency levels. TSL 5 would save an estimated 2.47 quads of energy, an amount DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $2.63 billion using a discount rate of 7 percent, and $9.63 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 77.57 Mt of CO_2, 29.81 thousand tons of SO_2, 123.44 thousand tons of NO_X, 0.19 tons of Hg, 567.30 thousand tons of CH_4, and 0.70 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 $2.77 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 5 is $1.53 billion using a 7-percent discount rate and $4.91 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 $6.94 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 5 is $17.31 billion.

At TSL 5, the average LCC impact ranges from $147 for equipment class 3 to $574 for equipment class 4. The median PBP ranges from 9.1 years for equipment class 4 to 11.7 years for equipment class 3. The fraction of consumers experiencing a net LCC cost ranges from 16 percent for equipment class 4 to 40 percent for equipment class 3.

At TSL 5, the projected change in INPV ranges from a decrease of $61.0 million to a decrease of $33.5 million, which corresponds to decreases of 31.4 percent and 17.2 percent, respectively. DOE estimates that industry must invest $69.4 million to comply with standards set at TSL 5.

After considering the analysis and weighing the benefits and burdens, the Secretary has tentatively concluded that at a standard set at TSL 5 for low-voltage dry-type distribution transformers would be economically justified. At this TSL, the average LCC savings are positive across all equipment classes. An estimated 16 percent of equipment class 4 to 40 percent of equipment class 3 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. Notably, the benefits to consumers vastly outweigh the cost to manufacturers. At TSL 5, the NPV of consumer benefits, even measured at the more conservative discount rate of 7 percent is over 43.15 times higher than the maximum estimated manufacturers' loss in INPV. The standard levels at TSL 5 are economically justified even without weighing the estimated monetary value of emissions reductions. When those emissions reductions are included—representing $2.77 billion in climate benefits (associated with the average SC–GHG at a 3-percent discount rate), and $4.91 billion (using a 3-percent discount rate) or $1.53 billion (using a 7-percent discount rate) in health benefits—the rationale becomes stronger still.

The energy savings under TSL 5 are primarily achievable by using amorphous steel. Both global and domestic capacity of amorphous steel is greater than it was during the consideration of the April 2013 Standards Final Rule and global capacity of amorphous (estimated to be approximately 150,000–250,000 metric tons) is approximately equal to the U.S. demand for electrical steel in distribution transformer applications (estimated to be approximately 225,000 metric tons). Further, amorphous capacity grew in response to the April 2013 Standards Final Rule, although market demand did not necessarily grow in-kind. As such, there is currently excess amorphous steel capacity. Amorphous manufacturers response to the April 2013 Standards Final Rule demonstrates that amorphous capacity can be added quickly and is limited more by the market demand for amorphous steel rather that the ability to build out new supply. Stakeholders have expressed willingness to increase supply to match any potential demand created by an amended efficiency standard. The majority of electrical steel use in distribution transformer applications is associated with liquid-immersed distribution transformer. Therefore, a proposed standard for liquid-immersed distribution transformers that requires amorphous steel would result in amorphous capacity quickly rising to meet demand before the effective date of any amended energy conservation standards. The increased amorphous capacity would then be able to serve both the liquid-immersed and the low-voltage dry-type market.

As discussed in section V.C.1, the consistent practice of distribution transformer customers to lightly-load their distribution transformers, means that the majority of energy savings are associated with reducing no-load losses. While higher grades of GOES may have slightly improved no-load loss characteristics, amorphous steel tends to reduce no-load losses by over 60 percent. By nature of DOE evaluating efficiency of low-voltage dry-type distribution transformers at 35 percent load, even if loading increases such that in-service RMS average PUL is 35 percent, the distribution transformers produced under the amended efficiency standard would be more efficient than minimally efficient transformers on the market today.

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.

Although DOE considered proposed amended standard levels for distribution transformers by grouping the efficiency levels (ELs) for each equipment class into TSLs, DOE evaluates all analyzed efficiency levels in its analysis. For low-voltage dry-type distribution transformers, TSL 5 (*i.e.,* the proposed TSL) maps directly to EL 5 for each equipment class and represents a 50 percent reduction in losses over the current standard for single-phase distribution transformers, and a 40 percent reduction in losses over the current standard for three-phase distribution transformers.

Therefore, based on the previous considerations, DOE proposes to adopt the energy conservation standards for low-voltage dry-type distribution transformers at TSL 5. The proposed amended energy conservation standards for low-voltage dry-type distribution transformers, which are expressed as percentage efficiency at 35 percent PUL are shown in Table V.75.

TABLE V.75—PROPOSED AMENDED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

Equipment class 3		Equipment class 4	
Single-phase		Three-phase	
kVA		kVA	
15	98.84	15	98.72
25	98.99	30	98.93
37.5	99.09	45	99.03
50	99.14	75	99.16
75	99.24	112.5	99.24
100	99.30	150	99.29
167	99.35	225	99.36
250	99.40	300	99.41
333	99.45	500	99.48
		750	99.54
		1,000	99.57

3. Benefits and Burdens of TSLs Considered for Medium-Voltage Dry-Type Distribution Transformers Standards

Table V.76 and Table V.77 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 (2027–2056). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. The efficiency levels contained in each TSL are described in section V.A of this document. Table V.77 shows the consumer impacts as equipment classes, which are the shipment weighted average results of each equipment class's representative units. The consumer results for each representative unit and information on the fraction of shipments they represent are shown in section B.1.

TABLE V.76—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS TSLS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Cumulative FFC National Energy Savings					
Quads	0.08	**0.12**	0.40	0.53	0.63
Cumulative FFC Emissions Reduction					
CO_2 (*million metric tons*)	2.53	**3.71**	12.68	16.48	19.72
CH_4 (*thousand tons*)	18.59	**27.29**	93.13	121.07	144.90
N_2O (*thousand tons*)	0.02	**0.03**	0.11	0.15	0.18
NO_X (*thousand tons*)	4.04	**5.93**	20.24	26.31	31.49
SO_2 (*thousand tons*)	0.97	**1.43**	4.87	6.33	7.58
Hg (*tons*)	0.01	**0.01**	0.03	0.04	0.05
Present Value of Benefits and Costs (3% discount rate, billion 2021$)					
Consumer Operating Cost Savings	0.28	**0.41**	2.12	2.50	2.72
Climate Benefits *	0.09	**0.13**	0.45	0.59	0.71
Health Benefits **	0.16	**0.24**	0.80	1.04	1.25
Total Benefits †	0.53	**0.77**	3.38	4.13	4.67
Consumer Incremental Product Costs ‡	0.02	**0.19**	0.87	1.19	1.76
Consumer Net Benefits	0.26	**0.21**	1.25	1.30	0.96
Total Net Benefits	0.51	**0.58**	2.50	2.94	2.92
Present Value of Benefits and Costs (7% discount rate, billion 2021$)					
Consumer Operating Cost Savings	0.10	**0.14**	0.74	0.87	0.95
Climate Benefits *	0.09	**0.13**	0.45	0.59	0.71
Health Benefits **	0.05	**0.07**	0.25	0.33	0.39
Total Benefits †	0.24	**0.35**	1.44	1.79	2.04
Consumer Incremental Product Costs ‡	0.01	**0.10**	0.47	0.64	0.94
Consumer Net Benefits	0.09	**0.04**	0.27	0.23	0.00
Total Net Benefits	0.23	**0.24**	0.97	1.14	1.10

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the equipment shipped in 2027–2056.

* 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–N2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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_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 consumer, climate, and health benefits. Total 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.69 for net benefits using all four SC–GHG estimates.

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

TABLE V.77—SUMMARY OF ANALYTICAL RESULTS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS TSLS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1 *	TSL 2 *	TSL 3 *	TSL 4 *	TSL 5 *
Manufacturer Impacts					
Industry NPV (*million 2021$*) (No-new-standards case INPV = $87 million	85	**85 to 86**	71 to 80	69 to 80	65 to 82
Industry NPV (*% change*)	(2.1)	**(3.0) to (0.9)**	(18.7) to (8.8)	(21.4) to (7.8)	(25.9) to (5.9)
Consumer Average LCC Savings (2021$)					
Equipment Class 6 *	1,227	**833**	(165)	(985)	(1,557)
Equipment Class 8 *	4,556	**3,016**	647	224	(3,727)
Equipment Class 10 *	(1,209)	**(2,528)**	(5,704)	(5,569)	(9,558)
Shipment-Weighted Average **	1,594	**641**	(1,139)	(1,348)	(3,898)
Consumer Simple PBP (years)					
Equipment Class 6 *	1.9	**4.5**	12.1	17.0	15.6
Equipment Class 8 *	0.4	**1.9**	13.5	14.1	18.0
Equipment Class 10 *	24.9	**24.9**	22.3	19.8	21.8
Shipment-Weighted Average **	7.9	**8.9**	14.1	13.7	16.3
Percent of Consumers that Experience a Net Cost					
Equipment Class 6 *	7	**16**	48	68	59
Equipment Class 8 *	3	**11**	48	51	77
Equipment Class 10 *	83	**83**	77	82	92
Shipment-Weighted Average **	22	**26**	42	46	58

The entry ''n.a.'' means not applicable because there is no change in the standard at certain TSLs.

* The equipment classes, shown here are the shipment weighted average results of each equipment class's representative units. The consumer results for each representative unit and information on the fraction of shipments they represent are shown in section B.1.

** Scaled across the representative capacities of each equipment class and weighted by shares of each equipment class in total projected shipments in 2022.

First, DOE considered TSL 5, which represents the max-tech efficiency levels. TSL 5 would save an estimated 0.63 quads of energy, an amount DOE considers significant. Under TSL 5, the NPV of consumer benefit would be $3 million using a discount rate of 7 percent, and $0.96 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 5 are 19.72 Mt of CO_2, 7.58 thousand tons of SO_2, 31.49 thousand tons of NO_X, 0.05 tons of Hg, 144.90 thousand tons of CH_4, and 0.18 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 $0.71 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 5 is $0.39 billion using a 7-percent discount rate and $1.25 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 $1.10 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 5 is $2.92 billion.

At TSL 5, the average LCC impact ranges from $−9,558 for equipment class 10 to $−1557 for equipment class 6. The mean PBP ranges from 15.6 years for equipment class 6 to 21.8 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 92 percent for equipment class 10 to 59 percent for equipment class 6.

At TSL 5, the projected change in INPV ranges from a decrease of $22.6 million to a decrease of $5.2 million, which corresponds to decreases of 25.9 percent and 5.9 percent, respectively. DOE estimates that industry must invest $21.2 million to comply with standards set at TSL 5.

The Secretary tentatively 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 58 percent. Further DOE estimates that there is a substantial risk to consumers, with a shipment weighted LCC savings for all MVDT equipment of −$3,898. Consequently, the Secretary has tentatively concluded that TSL 5 is not economically justified.

Next, DOE considered TSL 4, which would save an estimated 0.53 quads of energy, an amount DOE considers significant. Under TSL 4, the NPV of consumer benefit would be $0.23 billion using a discount rate of 7 percent, and $1.30 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 16.48 Mt of CO_2, 6.33 thousand tons of SO_2, 26.31 thousand tons of NO_X, 0.04 tons of Hg, 121.07 thousand tons of CH_4, and 0.15 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 $0.59 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 4 is $0.33 billion using a 7-percent discount rate and $1.04 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 $1.14 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $2.94 billion.

At TSL 4, the average LCC impact ranges from $−5,569 for equipment class 10 to $224 for equipment class 8. The mean PBP ranges from 14.1 years for equipment class 8 to 19.8 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 51 percent for equipment class 8 to 82 percent for equipment class 10.

At TSL 4, the projected change in INPV ranges from a decrease of $18.7 million to a decrease of $6.8 million, which corresponds to decreases of 21.4 percent and 7.8 percent, respectively. DOE estimates that industry must invest $19.2 million to comply with standards set at TSL 4.

The Secretary tentatively 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 iyn a reduction in INPV for manufacturers. At TSL 4 DOE is estimating negative benefits for a disproportionate fraction of consumers shipment weighted average of 53 percent. Further DOE estimates that there a substantial risk to consumers with a shipment weighted LCC savings for all MVDT equipment of −$1,348. Consequently, the Secretary has tentatively concluded that TSL 4 is not economically justified.

Next, DOE considered TSL 3, which would save an estimated 0.40 quads of energy, an amount DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $0.27 billion using a discount rate of 7 percent, and $1.25 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 12.68 Mt of CO_2, 4.87 thousand tons of SO_2, 20.24 thousand tons of NO_X, 0.03 tons of Hg, 93.13 thousand tons of CH_4, and 0.11 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 $0.45 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 3 is $0.25 billion using a 7-percent discount rate and $0.80 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 $0.97 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 3 is $2.50 billion.

At TSL 3, the average LCC impact ranges from $−5,704 for equipment class 10 to $647 for equipment class 8. The mean PBP ranges from 12.1years for equipment class 6 to 22.3 years for equipment class 10. The fraction of consumers experiencing a net LCC cost ranges from 77 percent for 10 to 48 percent for both equipment class 6 and 8.

At TSL 3, the projected change in INPV ranges from a decrease of $16.3 million to a decrease of $7.7 million, which corresponds to decreases of 18.7 percent and 8.8 percent, respectively. DOE estimates that industry must invest $17.9 million to comply with standards set at TSL 3.

The Secretary tentatively 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 is estimating negative benefits for a disproportionate fraction of consumers shipment weighted average of 50 percent. Further DOE estimates that there a substantial risk to consumers with a shipment weighted LCC savings for all MVDT equipment of −$1,139. Consequently, the Secretary has tentatively concluded that TSL 3 is not economically justified.

Next, DOE considered TSL 2, which would save an estimated 0.12 quads of energy, an amount DOE considers significant. Under TSL 2, the NPV of consumer benefit would be $0.04 billion using a discount rate of 7 percent, and $0.21 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 2 are 3.71 Mt of CO_2, 1.43 thousand tons of SO_2, 5.93 thousand tons of NO_X, 0.01 tons of Hg, 27.29 thousand tons of CH_4, and 0.03 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 $0.13 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 2 is $0.07 billion using a 7-percent discount rate and $0.24 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 $0.24 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 2 is $0.58 billion.

At TSL 2, the average LCC impact ranges from −$2,528 for equipment class 10 to $3,016 for equipment class 8. The mean PBP ranges from 1.9 years for equipment class 8 to 24.9 years for equipment class 10, which is below the mean lifetime of 32 years. The fraction of consumers experiencing a net LCC cost ranges from 11 percent for equipment class 8 to 83 percent for equipment class 10.

At TSL 2, the projected change in INPV ranges from a decrease of $2.7 million to a decrease of $0.8 million, which corresponds to decreases of 3.0 percent and 0.9 percent, respectively. DOE estimates that industry must invest $3.1 million to comply with standards set at TSL 2.

After considering the analysis and weighing the benefits and burdens, the Secretary has tentatively 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 $641. An estimated 11 percent of equipment class 8 to 83 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 26 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 38.3 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 $0.13 billion in climate benefits (associated with the average SC–GHG at a 3-percent discount rate), and $0.24 billion (using a 3-percent discount rate) or $0.07 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.

Although DOE considered proposed amended standard levels for distribution by grouping the efficiency levels for each equipment class 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 −$2,528, they are positive for all other equipment representing 78 percent of all MVDT units shipped, additionally the consumer benefits at EL 2, excluding equipment class 10, increases from $641 to $1,271 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.77.

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 most equipment, with a shipment weighted average consumer benefit of −$3,898, −$1,348, and −$1,139, respectively, while at TSL 2 it is $641. Therefore, DOE has tentatively 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 42, 46, and 58 percent, respectively.

Therefore, based on the previous considerations, DOE proposes to adopt the energy conservation standards for medium-voltage dry-type distribution transformers at TSL 2. The proposed amended energy conservation standards for medium-voltage dry-type distribution transformers, which are expressed as percentage efficiency at 50 percent PUL are shown in Table V.78.

TABLE V.78—PROPOSED AMENDED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS

[Electrical efficiency by kVA and equipment class]

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
Equipment class	EC5	EC7	EC9		EC6	EC8	EC10
15	98.29	98.07		15	97.74	97.45	
25	98.49	98.30		30	98.11	97.86	
37.5	98.64	98.47		45	98.29	98.07	
50	98.74	98.58		75	98.49	98.31	
75	98.86	98.71	98.68	112.5	98.67	98.52	
100	98.94	98.80	98.77	150	98.78	98.66	
167	99.06	98.95	98.92	225	98.94	98.82	98.71
250	99.16	99.05	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	99.23	1000	99.35	99.28	99.20
833	99.38	99.31	99.28	1500	99.43	99.37	99.29

TABLE V.78—PROPOSED AMENDED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DRY-TYPE DISTRIBUTION TRANSFORMERS—Continued

[Electrical efficiency by kVA and equipment class]

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
Equipment class	EC5	EC7	EC9		EC6	EC8	EC10
				2000	99.49	99.42	99.35
				2500	99.52	99.47	99.40
				3750	99.58	99.53	99.47
				5000	99.62	99.58	99.51

4. Annualized Benefits and Costs of the Proposed Standards for Liquid-Immersed Distribution Transformers

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2021$) of the benefits from operating products that meet the proposed 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 from emission reductions.

Table V.79 shows the annualized values for the proposed standards for distribution transformers, expressed in 2021$. 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 reduction benefits, and a 3-percent discount rate case for GHG social costs, the estimated cost of the proposed standards for distribution transformers is $424.8 million per year in increased equipment costs, while the estimated annual benefits are $451.9 million from reduced equipment operating costs, $497.4 million from GHG reductions, and $495.3million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $1,019.8 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards for distribution transformers is $429.5 million per year in increased equipment costs, while the estimated annual benefits are $7,33.5 million in reduced operating costs, $497.4 million from GHG reductions, and $894.3 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $1,695.8 million per year.

TABLE V.79—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR LIQUID-IMMERSED DISTRIBUTION TRANSFORMERS (TSL 4)

Category	Million 2021$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	733.5	686.9	789.9
Climate Benefits *	497.4	478.9	519.5
Health Benefits **	894.3	860.5	934.8
Total Benefits †	2,125.3	2,026.3	2,244.2
Consumer Incremental Equipment Costs ‡	429.5	449.0	413.2
Net Benefits	1,695.8	1,577.3	1,831.0
7% discount rate			
Consumer Operating Cost Savings	451.9	425.7	482.2
Climate Benefits * (3% discount rate)	497.4	478.9	519.5
Health Benefits **	495.3	477.9	515.3
Total Benefits †	1,444.7	1,382.5	1,517.0
Consumer Incremental Equipment Costs ‡	424.8	442.1	409.9
Net Benefits	1,019.8	940.5	1,107.2

This table presents the annualized costs and benefits associated with liquid-immersed distribution transformers equipment shipped in 2027–2056. These results include benefits to consumers which accrue after 2055 from the products purchased in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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 $PM_{2.5}$ 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.2 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.

5. Annualized Benefits and Costs of the Proposed Standards for Low-Voltage Distribution Transformers

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2021$) of the benefits from operating products that meet the proposed 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 from emission reductions.

Table V.80 shows the annualized values for the proposed standards for distribution transformers, expressed in 2021$. 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 reduction benefits, and a 3-percent discount rate case for GHG social costs, the estimated cost of the proposed standards for distribution transformers is $216.9 million per year in increased equipment costs, while the estimated annual benefits are $495.0 million from reduced equipment operating costs, $159.2 million from GHG reductions, and $162.1 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $599.4 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards for distribution transformers is $219.3 million per year in increased equipment costs, while the estimated annual benefits are $772.1 million in reduced operating costs, $159.2 million from GHG reductions, and $281.8 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $993.8 million per year.

TABLE V.80—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR LOW-VOLTAGE DISTRIBUTION TRANSFORMERS (TSL 5)

Category	Million 2021$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	772.1	716.9	831.3
Climate Benefits *	159.2	151.6	165.9
Health Benefits **	281.8	268.3	293.9
Total Benefits †	1,213.1	1,136.7	1,291.1
Consumer Incremental Product Costs ‡	219.3	228.7	208.7
Net Benefits	993.8	908.0	1,082.4
7% discount rate			
Consumer Operating Cost Savings	495.0	462.8	528.7
Climate Benefits * (3% discount rate)	159.2	151.6	165.9
Health Benefits **	162.1	154.9	168.2
Total Benefits †	816.3	769.3	862.8
Consumer Incremental Product Costs ‡	216.9	225.2	207.3
Net Benefits	599.4	544.1	655.5

This table presents the annualized costs and benefits associated with low-voltage dry-type distribution transformers equipment shipped in 2027–2056. These results include benefits to consumers which accrue after 2055 from the products purchased in 2027–2056.

* 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–N2O) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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 $PM_{2.5}$ 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.2 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.

6. Annualized Benefits and Costs of the Proposed Standards for Medium-Voltage Distribution Transformers

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2021$) of the benefits from operating products that meet the proposed 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 from emission reductions.

Table V.81 shows the annualized values for the proposed standards for distribution transformers, expressed in 2021$. 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 reduction benefits, and a 3-percent discount rate case for GHG social costs, the estimated cost of the proposed standards for distribution transformers is $10.8 million per year in increased equipment costs, while the estimated annual benefits are $14.9 million from reduced equipment operating costs, $7.6 million from GHG reductions, and $7.8 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $19.5 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards for distribution transformers is $11.0 million per year in increased equipment costs, while the estimated annual benefits are $23.3 million in reduced operating costs, $7.6 million from GHG reductions, and $13.5 million from reduced NO_X and SO_2 emissions. In this case, the net benefit amounts to $33.5 million per year.

TABLE V.81—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR MEDIUM-VOLTAGE DISTRIBUTION TRANSFORMERS (TSL 2)

Category	Million 2021$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	23.3	22.2	25.8
Climate Benefits *	7.6	7.5	8.2
Health Benefits **	13.5	13.2	14.5
Total Benefits †	44.4	42.9	48.5
Consumer Incremental Product Costs ‡	11.0	11.7	10.7
Net Benefits	33.5	31.1	37.7
7% discount rate			
Consumer Operating Cost Savings	14.9	14.3	16.4
Climate Benefits * (3% discount rate)	7.6	7.5	8.2
Health Benefits **	7.8	7.6	8.3
Total Benefits †	30.3	29.4	32.9
Consumer Incremental Product Costs ‡	10.8	11.6	10.6
Net Benefits	19.5	17.9	22.2

This table presents the annualized costs and benefits associated with medium-voltage dry-type distribution transformers equipment shipped in 2027 − 2056. These results include benefits to consumers which accrue after 2055 from the products purchased in 2027 − 2056.

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), as shown in Table V.73, Table V.74, and Table V.75. 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. As reflected in this rule, DOE has reverted to its approach prior to the injunction and present monetized greenhouse gas abatement 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 $PM_{2.5}$ 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.2 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.

7. Benefits and Costs of the Proposed Standards for all Considered Distribution Transformers

As described in sections V.C.1 through V.C.6, for this NOPR DOE is proposing TSL 4 for liquid-immersed, TSL 5 for low-voltage dry-type, and TSL 2 for medium-voltage dry-type distribution transformers. Table VI.1 shows the combined cumulative benefits, and Table V.83 shows the combined annualized benefits for the proposed levels for all distribution transformers.

TABLE V.82—SUMMARY OF MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AT PROPOSED STANDARD LEVELS

	Billion $2021
3% discount rate	
Consumer Operating Cost Savings	26.63
Climate Benefits *	11.56
Health Benefits **	20.72
Total Benefits †	58.91
Consumer Incremental Product Costs ‡	11.49
Net Benefits	47.42
7% discount rate	
Consumer Operating Cost Savings	9.11
Climate Benefits * (3% discount rate)	11.56
Health Benefits **	6.29
Total Benefits †	26.97
Consumer Incremental Product Costs ‡	6.17
Net Benefits	20.79

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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.69 for net benefits using all four SC–GHG estimates.

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

TABLE V.8384—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AT PROPOSED STANDARD LEVELS

Category	Million 2021$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	1,528.9	1,426.0	1,647.0
Climate Benefits *	664.2	638.0	693.6
Health Benefits **	1,189.6	1,142.0	1,243.2
Total Benefits †	3,382.8	3,205.9	3,583.8
Consumer Incremental Product Costs ‡	659.8	689.4	632.6
Net Benefits	2,723.1	2,516.4	2,951.1
7% discount rate			
Consumer Operating Cost Savings	961.8	902.8	1,027.3
Climate Benefits * (3% discount rate)	664.2	638.0	693.6
Health Benefits **	665.2	640.4	691.8
Total Benefits †	2,291.3	2,181.2	2,412.7
Consumer Incremental Product Costs ‡	652.5	678.9	627.8
Net Benefits	1,638.7	1,502.5	1,784.9

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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.69 for net benefits using all four SC–GHG estimates.

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

D. Reporting, Certification, and Sampling Plan

Manufacturers, including importers, must use product-specific certification templates to certify compliance to DOE. For distribution transformers, the certification template reflects the general certification requirements specified at 10 CFR 429.12 and the product-specific requirements specified at 10 CFR 429.47. As discussed in the previous paragraphs, DOE is not proposing to amend the product-specific certification requirements for this equipment.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Orders 12866 and 13563

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), 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 proposed/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 proposed regulatory action constitutes an economically significant regulatory action under section 3(f) 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 proposed 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. A summary of the potential costs and benefits of the regulatory action is presented in Table VI.1 and Table VI.2.

TABLE VI.1—SUMMARY OF MONETIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AND PROPOSED STANDARD LEVELS

	Billion $2021
3% discount rate	
Consumer Operating Cost Savings	26.63
Climate Benefits *	11.56
Health Benefits **	20.72
Total Benefits †	58.91
Consumer Incremental Product Costs ‡	11.49
Net Benefits	47.42
7% discount rate	
Consumer Operating Cost Savings	9.11
Climate Benefits * (3% discount rate)	11.56
Health Benefits **	6.29
Total Benefits †	26.97
Consumer Incremental Product Costs ‡	6.17
Net Benefits	20.79

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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.69 for net benefits using all four SC–GHG estimates.

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

TABLE VI.2—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AND PROPOSED STANDARD LEVELS

Category	Million 2021$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate			
Consumer Operating Cost Savings	1,528.9	1,426.0	1,647.0
Climate Benefits *	664.2	638.0	693.6
Health Benefits **	1,189.6	1,142.0	1,243.2
Total Benefits †	3,382.8	3,205.9	3,583.8
Consumer Incremental Product Costs ‡	659.8	689.4	632.6
Net Benefits	2,723.1	2,516.4	2,951.1
7% discount rate			
Consumer Operating Cost Savings	961.8	902.8	1,027.3

TABLE VI.2—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR ALL DISTRIBUTION TRANSFORMERS AND PROPOSED STANDARD LEVELS—Continued

Category	Million 2021$/year		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
Climate Benefits * (3% discount rate)	664.2	638.0	693.6
Health Benefits **	665.2	640.4	691.8
Total Benefits †	2,291.3	2,181.2	2,412.7
Consumer Incremental Product Costs ‡	652.5	678.9	627.8
Net Benefits	1,638.7	1,502.5	1,784.9

This table presents the costs and benefits associated with distribution transformers shipped in 2027–2056. These results include benefits to consumers which accrue after 2056 from the products shipped in 2027–2056.

* 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), as shown in Table V.73, Table V.74, and Table V.75. 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.69 for net benefits using all four SC–GHG estimates.

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

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis (''IRFA'') for any rule that by law must be proposed for public comment, 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 IRFA 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 North American Industry Classification System (''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 750 employees or fewer for an entity to be considered as a small business for this category.

1. Description of Reasons Why Action Is Being Considered

EPCA requires that, not later than 6 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(e)(1); 42 U.S.C. 6295(m)(1)).

2. Objectives of, and Legal Basis for, Rule

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) and 42 U.S.C. 6295(o)(3)(B)).

3. Description on Estimated Number of Small Entities Regulated

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), DOE's publicly available Compliance Certification Database (''CCD''), California Energy Commission's MAEDBS database 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 29 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 27 companies that are OEMs, DOE identified 10 potential companies that have fewer than 750 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 four small businesses that only manufacture LVDT distribution transformers.[115]

Liquid-Immersed

Liquid-immersed distribution transformers account for over 80 percent of all distribution transformer shipments covered by this rulemaking. Six major manufacturers supply more than 80 percent of the market for liquid-immersed distribution transformers covered by this rulemaking. None of these six 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

LVDT distribution transformers account for approximately 18 percent of all distribution shipments covered by this rulemaking. Four major manufacturers supply more than 80 percent of the market for LVDT distribution transformers covered by this rulemaking. None of these four 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

MVDT distribution transformers account for less than one percent of all distribution transformer shipments covered by this rulemaking. There is one large MVDT distribution transformer manufacturer with a substantial share of the market. 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 and Estimate of Compliance Requirements Including Differences in Cost, if Any, for Different Groups of Small Entities

Liquid-Immersed and Low-Voltage Dry-Type

DOE is proposing to amend energy conservation standards to be at TSL 4 for liquid-immersed distribution transformers and TSL 5 for LVDT distribution transformers. This corresponds to EL 4 for most liquid-immersed distribution transformer equipment classes and EL 5 for all LVDT distribution transformer equipment classes.

Based on the LCC consumer choice model, DOE anticipates that most, if not all, liquid-immersed and LVDT distribution transformer manufacturers would use amorphous cores in their distribution transformers to meet these proposed amended energy conservation standards. While DOE anticipates that several large liquid-immersed and LVDT 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 need 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 able to identify one LVDT small business that manufactures their own cores and was not able to identify any liquid-immersed small businesses that manufacture their own cores. The one LVDT small business that is currently manufacturing their own cores would have to make a business decision to either make a significant capital investment to be able to make amorphous cores or to out-source the production of their LVDT cores. Out-sourcing 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.

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 proposed energy conservation standards for liquid-immersed and LVDT distribution transformers. DOE anticipates that there will be an increase in the number of large liquid-immersed and LVDT distribution transformer manufacturers that will out-source 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 and LVDT 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

[115] Therefore, there are a total of seven small businesses that manufacture LVDT distribution transformers. Four that exclusively manufacture LVDT and three that manufacture both LVDT and MVDT.

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 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 and 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 additional year 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 and LVDT small businesses would incur an additional 3.0 percent of annual revenue to redesign their distribution transformers to be able to accommodate using amorphous cores there were purchased from core manufacturers.

Medium-Voltage Dry-Type

DOE is proposing to amend 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 does not anticipate that any MVDT distribution transformer manufacturers would use amorphous cores in their MVDT distribution transformers to meet these proposed energy conservation standards. DOE does not anticipate that MVDT manufacturers would make significant investments to either be able to produce cores capable of meeting these proposed 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, estimates that manufacturers would incur approximately a half of a year of additional R&D expenditure to redesign their distribution transformers to higher efficiency levels, while not using amorphous 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 1.5 percent of annual revenue to redesign, MVDT distribution transformers to higher efficiency levels that could be met without using amorphous cores.

DOE requests comment on the number of small businesses identified that manufacture distribution transformers covered by this rulemaking (three small liquid-immersed and seven LVDT small businesses; three of which also manufacture MVDT). Additionally, DOE requests comment on its initial assumption that only one LVDT small business and no liquid-immersed small businesses manufacturer their own cores used in their distribution transformers.

5. Duplication, Overlap, and Conflict With Other Rules and Regulations

Starting in 2018, imports of raw electrical steel have been subject to a 25 percent *ad valorem* tariff. This tariff does not apply to products made from electrical steel, such as transformer laminations and finished cores. In a report published on November 18, 2021, the Department of Commerce presented its conclusions and potential options to ensure the domestic supply chain of electrical steel and transformer components. 86 FR 64606 However, no modifications to the tariff structure have been made at the time of publication of this NOPR. As discussed in section IV.A.5, modification to the tariff structure could impact the pricing and availability of certain electrical steel grades depending on each manufacturer's given supply chain and sourcing practices.

DOE is not aware of any other rules or regulations that duplicate, overlap, or conflict with the rule being considered today.

6. Significant Alternatives to the Rule

The discussion in the previous section analyzes impacts on small businesses that would result from DOE's proposed rule, represented by TSL 4 for liquid-immersed distribution transformer equipment classes; TSL 5 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 60 percent lower energy savings compared to the energy savings at TSL 4; TSL 2 achieves 37 percent lower energy savings compared to the energy savings at TSL 4. For LVDT equipment classes TSL 1 achieves 85 percent lower energy savings compared to the energy savings at TSL 5; TSL 2 achieves 78 percent lower energy savings compared to the energy savings at TSL 5; TSL 3 achieves 66 percent lower energy savings compared to the energy savings at TSL 5; and TSL 4 achieves 8 percent lower energy savings compared to the energy savings at TSL 5. For MVDT equipment classes TSL 1 achieves 33 percent lower energy savings compared to the energy savings at TSL 2.

Based on the presented discussion, DOE tentatively concludes that the benefits of the energy savings from TSL 4 for liquid-immersed equipment classes; TSL 5 for LVDT equipment classes; and TSL 2 for MVDT equipment classes exceed the potential burdens placed on distribution transformers manufacturers, including small business manufacturers. Accordingly, DOE does not propose 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 NOPR TSD.

Additional compliance flexibilities may be available through other means. EPCA provides that a manufacturer whose annual gross revenue from all of its operations does not exceed $8 million may apply for an exemption from all or part of an energy conservation standard for a period not longer than 24 months after the effective date of a final rule establishing the standard. (42 U.S.C. 6295(t)) Additionally, 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

DOE is analyzing this proposed regulation in accordance with the National Environmental Policy Act of 1969 (''NEPA'') and DOE's NEPA implementing regulations (10 CFR part 1021). DOE's regulations include a categorical exclusion for rulemakings that establish energy conservation standards for consumer products or industrial equipment. 10 CFR part 1021, subpart D, appendix B5.1. DOE anticipates that this rulemaking qualifies for categorical exclusion B5.1 because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, none of the exceptions identified in categorical exclusion B5.1(b) apply, no extraordinary circumstances exist that require further environmental analysis, and it otherwise meets the requirements for application of a categorical exclusion. See 10 CFR 1021.410. DOE will complete its NEPA review before issuing the final rule.

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 proposed rule and has tentatively 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 are the subject of this proposed rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6297) 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 Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, this proposed 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, section 201 (codified at 2 U.S.C. 1531). For a proposed 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 proposed ''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.*

Although this proposed rule does not contain a Federal intergovernmental mandate, it 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 transformers 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 proposed 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 NOPR and the TSD for this proposed rule respond to those requirements.

Under section 205 of UMRA, the Department is obligated to identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a written statement under section 202 is required. (2 U.S.C. 1535(a)) DOE is required to select from those alternatives the most cost-effective and least burdensome alternative that achieves the objectives of the proposed rule unless DOE publishes an explanation for doing otherwise, or the selection of such an alternative is inconsistent with law. As required by 42 U.S.C. 6295(m) [or a product-specific directive in 42 U.S.C. 6295 or 42 U.S.C. 6313], this proposed rule would establish 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. 6295(o)(2)(A) and 42 U.S.C. 6295(o)(3)(B). A full discussion of the alternatives considered by DOE is presented in chapter 17 of the TSD for this proposed rule.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This proposed rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

Pursuant to E.O. 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights,'' 53 FR 8859 (Mar. 15, 1988), DOE has determined that this proposed 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 NOPR 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 proposed 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 proposed 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 tentatively concluded that this regulatory action, which proposes amended energy conservation standards for distribution transformers, is not a significant energy action because the proposed 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 proposed 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 has prepared a report describing that peer review.[116] 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 the Department's analyses. DOE is in the process of evaluating the resulting report.[117]

VII. Public Participation

A. Attendance at the Public Meeting

The time and date of the webinar meeting are listed in the **DATES** section at the beginning of this document. Webinar registration information, participant instructions, and information about the capabilities available to webinar participants will be published on DOE's website: *www.eere.energy.gov/buildings/appliance_standards/standards.aspx?productid=55.*

[116] 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 January 2022).

[117] The report is available at *www.nationalacademies.org/our-work/review-of-methods-for-setting-building-and-equipment-performance-standards.*

Participants are responsible for ensuring their systems are compatible with the webinar software.

B. Procedure for Submitting Prepared General Statements for Distribution

Any person who has an interest in the topics addressed in this proposed rule, or who is representative of a group or class of persons that has an interest in these issues, may request an opportunity to make an oral presentation at the webinar. Such persons may submit to *ApplianceStandardsQuestions@ee.doe.gov.* Persons who wish to speak should include with their request a computer file in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format that briefly describes the nature of their interest in this rulemaking and the topics they wish to discuss. Such persons should also provide a daytime telephone number where they can be reached.

DOE requests persons selected to make an oral presentation to submit an advance copy of their statements at least two weeks before the webinar. At its discretion, DOE may permit persons who cannot supply an advance copy of their statement to participate, if those persons have made advance alternative arrangements with the Building Technologies Office. As necessary, requests to give an oral presentation should ask for such alternative arrangements.

DOE will designate a DOE official to preside at the webinar/public meeting and may also use a professional facilitator to aid discussion. The meeting will not be a judicial or evidentiary-type public hearing, but DOE will conduct it in accordance with section 336 of EPCA (42 U.S.C. 6306). A court reporter will be present to record the proceedings and prepare a transcript. DOE reserves the right to schedule the order of presentations and to establish the procedures governing the conduct of the webinar. There shall not be discussion of proprietary information, costs or prices, market share, or other commercial matters regulated by U.S. anti-trust laws. After the webinar and until the end of the comment period, interested parties may submit further comments on the proceedings and any aspect of the rulemaking.

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

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

A transcript of the webinar will be included in the docket, which can be viewed as described in the *Docket* section at the beginning of this proposed rule. In addition, any person may buy a copy of the transcript from the transcribing reporter.

C. Conduct of the Public Webinar

DOE will designate a DOE official to preside at the webinar/public meeting and may also use a professional facilitator to aid discussion. The meeting will not be a judicial or evidentiary-type public hearing, but DOE will conduct it in accordance with section 336 of EPCA (42 U.S.C. 6306). A court reporter will be present to record the proceedings and prepare a transcript. DOE reserves the right to schedule the order of presentations and to establish the procedures governing the conduct of the webinar. There shall not be discussion of proprietary information, costs or prices, market share, or other commercial matters regulated by U.S. anti-trust laws. After the webinar and until the end of the comment period, interested parties may submit further comments on the proceedings and any aspect of the rulemaking.

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

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

A transcript of the webinar will be included in the docket, which can be viewed as described in the *Docket* section at the beginning of this proposed rule. In addition, any person may buy a copy of the transcript from the transcribing reporter.

D. Submission of Comments

DOE will accept comments, data, and information regarding this proposed rule before or after the public meeting, but no later than the date provided in the **DATES** section at the beginning of this proposed rule. Interested parties may submit comments, data, and other information using any of the methods described in the **ADDRESSES** section at the beginning of this document.

Submitting comments via *www.regulations.gov.* The *www.regulations.gov* web page will require you to provide your name and contact information. Your contact information will be viewable to DOE Building Technologies staff only. Your contact information will not be publicly viewable except for your first and last names, organization name (if any), and submitter representative name (if any). If your comment is not processed properly because of technical difficulties, DOE will use this information to contact you. If DOE cannot read your comment due to technical difficulties and cannot contact you for clarification, DOE may not be able to consider your comment.

However, your contact information will be publicly viewable if you include it in the comment itself or in any documents attached to your comment. Any information that you do not want to be publicly viewable should not be included in your comment, nor in any document attached to your comment. Otherwise, persons viewing comments will see only first and last names, organization names, correspondence containing comments, and any documents submitted with the comments.

Do not submit to *www.regulations.gov* information for which disclosure is restricted by statute, such as trade secrets and commercial or financial information (hereinafter referred to as Confidential Business Information (''CBI'')). Comments submitted through *www.regulations.gov* cannot be claimed as CBI. Comments received through the website will waive any CBI claims for the information submitted. For information on submitting CBI, see the Confidential Business Information section.

DOE processes submissions made through *www.regulations.gov* before posting. Normally, comments will be posted within a few days of being submitted. However, if large volumes of comments are being processed simultaneously, your comment may not be viewable for up to several weeks. Please keep the comment tracking number that *www.regulations.gov* provides after you have successfully uploaded your comment.

Submitting comments via email. Comments and documents submitted via email also will be posted to *www.regulations.gov.* If you do not want your personal contact information to be publicly viewable, do not include it in your comment or any accompanying documents. Instead, provide your contact information in a cover letter. Include your first and last names, email address, telephone number, and optional mailing address. The cover letter will not be publicly viewable as long as it does not include any comments.

Include contact information each time you submit comments, data, documents, and other information to DOE. No telefacsimiles (''faxes'') will be accepted.

Comments, data, and other information submitted to DOE electronically should be provided in PDF (preferred), Microsoft Word or Excel, WordPerfect, or text (ASCII) file format. Provide documents that are not secured, that are written in English, and that are free of any defects or viruses. Documents should not contain special characters or any form of encryption and, if possible, they should carry the electronic signature of the author.

Campaign form letters. Please submit campaign form letters by the originating organization in batches of between 50 to 500 form letters per PDF or as one form letter with a list of supporters' names compiled into one or more PDFs. This reduces comment processing and posting time.

Confidential Business Information. Pursuant to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit via email two well-marked copies: one copy of the document marked ''confidential'' including all the information believed to be confidential, and one copy of the document marked ''non-confidential'' with the information believed to be confidential deleted. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

It is DOE's policy that all comments may be included in the public docket, without change and as received, including any personal information provided in the comments (except information deemed to be exempt from public disclosure).

E. Issues on Which DOE Seeks Comment

Although DOE welcomes comments on any aspect of this proposal, DOE is particularly interested in receiving comments and views of interested parties concerning the following issues:

(1) DOE requests comment on the proposed amendment to the definition of drive (isolation) transformer. DOE requests comment on its tentative determination that voltage ratings of 208Y/120 and 480Y/277 indicate a design for use in general purpose applications. DOE also requests comment on other voltage ratings or other characteristics that would indicate a design for use in general purpose applications.

(2) DOE requests comment on its proposed amendment to the definition of ''special-impedance transformer'' and whether it provides sufficient clarity as to how to treat the normal impedance ranges for non-standard kVA distribution transformers.

(3) DOE requests comment on its proposed definition for transformers with a tap range of 20 percent or more.

(4) DOE requests comment on its proposed amendments to the definitions of sealed and nonventilated transformers.

(5) DOE requests comment on its proposed amendment to the definition of uninterruptable power supply transformers.

(6) DOE requests comment as to whether its proposed definition better aligns with industries understanding on input and output voltages

(7) Further, DOE requests comment and data on whether the proposed amendment would impact products that are serving distribution applications, and if so, the number of distribution transformers impacted by the proposed amendment.

(8) DOE requests comment and data as to whether 5,000 kVA represents the upper end of what is considered distribution transformers or if another value should be used.

(9) DOE requests comment and data as to the number of shipments of three-phase, liquid-immersed, distribution transformers greater than 2,500 kVA that would meet the in-scope voltage limitations and the distribution of efficiencies of those units.

(10) DOE requests comment and data as to the number of shipments of three-phase, dry-type, distribution transformers greater than 2,500 kVA that would meet the in-scope voltage limitations and the distribution of efficiencies of those units.

(11) DOE requests comment on its understanding and proposed definition of ''submersible'' distribution transformer. Specifically, DOE requests information on specific design characteristics of distribution transformers that allow them to operate while submerged in water, as well as data on the impact to efficiency resulting from such characteristics.

(12) DOE requests comment and data as to the impact that submersible characteristics have on distribution transformer efficiency.

(13) DOE requests data on the difference in load loss by kVA for distribution transformers with multiple-voltage ratings and a voltage ratio other than 2:1.

(14) DOE request data on the number of shipments for each equipment class of distribution transformers with multi-voltage ratios other than 2:1.

(15) DOE requests data on the difference in load loss by kVA for distribution transformers with higher currents and at what current it becomes more difficult to meet energy conservation standards.

(16) DOE requests data as to the number of shipments of distribution transformers with the higher currents that would have a more difficult time meeting energy conservation standards.

(17) DOE requests comment as to what modifications could be made to the April 2013 Standard Final Rule data center definition such that the identifying features are related to efficiency and would prevent a data center transformer from being used in a general purpose application.

(18) DOE requests comment regarding its proposal not to establish a separate equipment class for data center distribution transformers. In particular,

DOE seeks comment regarding whether data center distribution transformers are able to reach the same efficiency levels as distribution transformers generally and the specific reasons why that may be the case.

(19) DOE requests comment regarding any challenges that would exist if designing a distribution transformer which uses amorphous electrical steel in its core for data center applications and whether data center transformers have been built which use amorphous electrical steel in their cores.

(20) DOE requests comment on the interaction of inrush current and data center distribution transformer design. Specifically, DOE seeks information regarding: (1) the range of inrush current limit values in use in data center distribution transformers; (2) any challenges in meeting such inrush current limit values when using amorphous electrical steel in the core; (3) whether using amorphous electrical steel inherently increases inrush current, and why; (4) how the (magnetic) remanence of grain-oriented electrical steel compares to that of amorphous steel; and (5) other strategies or technologies than distribution transformer design which could be used to limit inrush current and the respective costs of those measures.

(21) DOE requests data as to how a liquid-immersed distribution transformer losses vary with BIL across the range of kVA values within scope.

(22) DOE requests comments and data on any other types of equipment that may have a harder time meeting energy conservation standards. Specifically, DOE requests comments as to how these other equipment are identified based on physical features from general purpose distribution transformers, the number of shipments of each unit, and the possibility of these equipment being used in place of generally purpose distribution transformers.

(23) DOE requests data demonstrating any specific distribution transformer designs that would have significantly different cost-efficiency curves than those representative units modeled by DOE.

(24) DOE requests comment on its methodology for scaling RU5, RU12, and RU14 to represent the efficiency of units above 3,750 kVA.

(25) DOE requests comment on its methodology for modifying the results of RU4 and RU5 to represent the efficiency of submersible liquid-immersed units. For other potentially disadvantaged designs, DOE has considered establishing equipment classes to separate out those that would have the most difficulty achieving amended efficiency standards, as discussed in section IV.A.2 of this document, but ultimately has determined not to include such separate equipment classes in the proposed standards. However, DOE requests data as to the degree of reduction in efficiency associated with various features.

(26) DOE requests data as to how stray and eddy losses at rated PUL vary with kVA and rated voltages.

(27) DOE requests comment on the current and future market pressures influencing the price of GOES. Specifically, DOE is interested in the barriers to and costs associated with converting a factory production line from GOES to NOES.

(28) DOE further requests comment regarding how the prices of both GOES and amorphous are expected to change in the immediate and distant future.

(29) DOE requests comment regarding the barriers to converting current M3 or 23hib90 electrical steel production to lower-loss GOES core steels.

(30) DOE requests comment as to if there are markets for amorphous ribbon, similar to NOES competition from GOES production, which would put competitive pressures on the production of amorphous ribbon for distribution transformers.

(31) DOE requests comment on how a potentially limited supply of transformer core steel, both of amorphous and GOES, may affect core steel price and availability. DOE seeks comment on any factors which uniquely affect specific steel grades (*e.g.,* amorphous, M-grades, hib, dr, pdr). Additionally, DOE seeks comment on how it should model a potentially concentrated domestic steel market in its analysis, resulting from a limited number of suppliers for the amorphous market or from competition with NOES for the GOES market, including any use of game theoretic modeling as appropriate.

(32) DOE requests comment or data showing hourly transformer loads for industrial customers.

(33) To help inform DOE's prediction of future load growth trend, DOE seeks data on the following for regions where decarbonization efforts are ongoing. DOE seeks hourly PUL data at the level of the transformer bank for each of the past five years to establish an unambiguous relationship between transformer loads and decarbonization policy and inform if any intensive load growth is indeed occurring. Additionally, DOE seeks the average capacity of shipment into regions where decarbonization efforts are occurring over the same five-year period to inform the rate of any extensive load growth that may be occurring in response to these programs.

(34) DOE requests comments on its methodology for establishing the energy efficiency levels for distribution transformers greater than 2500 kVA. DOE request comment on its assumed energy efficiency ratings.

(35) DOE requests comment on its assumed TOC adoption rate of 10 percent. Specifically, DOE requests comment on the TOC rate suggested by NEMA, that between 15 and 20 percent of 3-phase liquid-immersed distribution transformers are purchased using TOC, and that 40 percent of 1-phase liquid-immersed distribution transformers are purchased using TOC. DOE notes, that it is seeking data related to concluded sales based on lowest TOC in the strictest sense, excluding those transformers sold using band of equivalents (see the section on band of equivalents, above)

(36) DOE requests comment on the fraction of distribution transformers purchased by customers using the BOE methodology. DOE notes, that it is seeking data related to concluded sales based on lowest BOE in the strictest sense, excluding those transformers sold using total owning costs.

(37) DOE request comment if the rates of TOC or BOE vary by transformer capacity or number of phases. Further, DOE seeks the fraction of distribution transformer sales using either method into the different regions in order to capture the believed relationship between higher electricity costs and purchase evaluation behavior.

(38) Transformers are typically installed using a bucket truck, or crane truck. DOE requests comment on the typical maximum lifting capacity, and the typical transformer capacity being installed.

(39) For this NOPR, DOE reiterates its request for the following information. DOE requests data and feedback on the size limitations of pad-mounted distribution transformers. Specifically, what sizes, voltages, or other features are currently unable to fit on current pads, and the dimension of these pads. DOE seeks data on the typical concrete pad dimensions for 50 and 500 kVA single-; and 500, and 1500 kVA three-phase distribution transformers. DOE seeks data on the typical service lifetimes of supporting concrete pads.

(40) DOE request the average extension of distribution transformer service life that can be achieved through rebuilding. Additionally, DOE requests comment on the fraction of transformer that are repaired by their original purchasing entity and returned to

service, thereby extending the transformer's service lifetime beyond the estimated lifetimes of 32 years with a maximum of 60 years.

(41) DOE requests comment on which liquid-immersed distribution transformers capacities are typically replaced with MVDT. DOE further requests data that would indicate a trend in these substitutions. DOE further requests data that would help it determine which types of customers are preforming these substitutions, *e.g.,* industrial customers, invertor owned utilities, MUNIs, etc.

(42) In response to NEMA's comment DOE requests data to inform a shift in the capacity distribution to larger capacity distribution transformers. Additionally, DOE requests information on the extent that this increasing trend in capacity would affect all types of distribution transformers, or only medium-voltage distribution transformers.

(43) DOE projected the energy savings, operating cost savings, product costs, and NPV of consumer benefits over the lifetime of distribution transformers sold from 2027 through 2056. Given the extremely durable nature of distribution transformers, this creates an analytical timeframe from 2027 through 2115. DOE seeks comment on the current analytical timeline, and potential alternative analytical timeframes.

(44) DOE requests comment on its assumption that including a rebound effect is inappropriate for distribution transformers.

(45) DOE requests comment on the mean PUL applied to distribution transformers owned and operated by utilities serving low customer populations.

(46) DOE requests comment on its assumed vault replacement costs methodology. DOE seeks comment or data regarding the installation procedures associated with vault replacement, vault expansion (renovation), and vault transformer installation and their respective costs for replacement transformers. Additionally, DOE seeks information on the typical expected lifetime of underground concrete vaults.

(47) DOE requests comment on the real discount rates used in this NOPR. Specifically, if 7.4 percent for liquid-immersed distribution transformer manufacturers, 11.1 percent for low-voltage dry-type distribution transformer manufacturers, and 9.0 percent for medium-voltage dry-type distribution transformer manufacturers are appropriate discount rates to use in the GRIM.

(48) DOE requests comment on the estimated potential domestic employment impacts on distribution transformer manufacturers presented in this NOPR.

(49) DOE requests comment on the potential availability of either amorphous steel, grain-oriented electrical steel, or any other materials that may be needed to meet any of the analyzed energy conservation standards in this rulemaking. More specifically, DOE requests comment on steel manufacturers' ability to increase supply of amorphous steel in reaction to increased demand for amorphous steel as a result of increased energy conservation standards for distribution transformers.

(50) DOE requests comment on the number of small businesses identified that manufacture distribution transformers covered by this rulemaking (three small liquid-immersed and seven LVDT small businesses; three of which also manufacture MVDT). Additionally, DOE requests comment on its initial assumption that only one LVDT small business and no liquid-immersed small businesses manufacturer their own cores used in their distribution transformers.

(51) Additionally, DOE welcomes comments on other issues relevant to the conduct of this rulemaking that may not specifically be identified in this document.

VIII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of this notice of proposed rulemaking and announcement of public meeting.

List of Subjects in 10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation test procedures, and Reporting and recordkeeping requirements.

Signing Authority

This document of the Department of Energy was signed on December 28, 2022, by Francisco Alejandro Moreno, Acting 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 December 29, 2022.

Treena V. Garrett,

Federal Register Liaison Officer, U.S. Department of Energy

For the reasons set forth in the preamble, DOE proposes to amend part 431 of chapter II, of title 10 of the Code of Federal Regulations, as set forth below:

PART 431—ENERGY EFFICIENCY PROGRAM FOR CERTAIN COMMERCIAL AND INDUSTRIAL EQUIPMENT

■ 1. The authority citation for part 431 continues to read as follows:

Authority: 42 U.S.C. 6291–6317; 28 U.S.C. 2461 note.

■ 2. Section 431.192 is amended by:

■ a. Revising the definitions of ''Distribution transformer'', ''Drive (isolation) transformer'', ''Nonventilated transformer'', ''Sealed transformer'', ''Special-impedance transformer'', ''Transformer with a tap range of 20 percent or more'', ''Uninterruptible power supply transformer''; and

■ b. Adding in alphabetical order, definition for ''Submersible distribution transformer''

The revisions and addition read as follows:

§ 431.19 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) Autotransfromer;

(ii) Drive (isolation) transformer;

(iii) Grounding transformer;

(iv) Machine-tool (control transformer);

(v) Nonventilated transformer;

(vi) Rectified 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 stressed 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 condition 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 show in Tables 1 and 2, respectively. 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.

TABLE 1—NORMAL IMPEDANCE RANGES FOR LIQUID-IMMERSED TRANSFORMERS

Single-phase		Three-phase	
kVA	Impedance (%)	kVA	Impedance (%)
10	1.0–4.5	15	1.0–4.5
15	1.0–4.5	30	1.0–4.5
25	1.0–4.5	45	1.0–4.5
37.5	1.0–4.5	75	1.0–5.0
50	1.5–4.5	112.5	1.2–6.0
75	1.5–4.5	150	1.2–6.0
100	1.5–4.5	225	1.2–6.0
167	1.5–4.5	300	1.2–6.0
250	1.5–6.0	500	1.5–7.0
333	1.5–6.0	750	5.0–7.5
500	1.5–7.0	1,000	5.0–7.5
667	5.0–7.5	1,500	5.0–7.5
833	5.0–7.5	2,000	5.0–7.5
		2,500	5.0–7.5
		3,750	5.0–7.5
		5,000	5.0–7.5

TABLE 2—NORMAL IMPEDANCE RANGES FOR DRY-TYPE TRANSFORMERS

Single-phase		Three-phase	
kVA	Impedance (%)	kVA	Impedance (%)
15	1.5–6.0	15	1.5–6.0
25	1.5–6.0	30	1.5–6.0
37.5	1.5–6.0	45	1.5–6.0
50	1.5–6.0	75	1.5–6.0
75	2.0–7.0	112.5	1.5–6.0
100	2.0–7.0	150	1.5–6.0
167	2.5–8.0	225	3.0–7.0
250	3.5–8.0	300	3.0–7.0
333	3.5–8.0	500	4.5–8.0
500	3.5–8.0	750	5.0–8.0
667	5.0–8.0	1,000	5.0–8.0
833	5.0–8.0	1,500	5.0–8.0
		2,000	5.0–8.0
		2,500	5.0–8.0
		3,750	5.0–8.0
		5,000	5.0–8.0

Submersible Distribution Transformer means 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.

* * * * *

Transformer with tap range of 20 percent or more means a transformer with multiple full-power voltage taps, the highest of which equals at least 20 percent more than the lowest, computed based on the sum of the deviations of these taps from the transformer's maximum full-power voltage.

Uninterruptible power supply transformer means a transformer that is used within an uninterruptible power system, which in turn supplies power to loads that are sensitive to power failure, power 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) through (4), and

■ c. Revising paragraph (c)(2) and adding paragraph (c)(3).

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 January 1, 2027, shall be no less than that required for the applicable kVA rating in the table below. Low-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

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

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

(3) The efficiency of a low-voltage dry-type distribution transformer manufactured on or after January 1, 2027, shall be no less than that required for their kVA rating in the table below. Low-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
15	98.84	15	98.72
25	98.99	30	98.93
37.5	99.09	45	99.03
50	99.14	75	99.16
75	99.24	112.5	99.24
100	99.30	150	99.29
167	99.35	225	99.36
250	99.40	300	99.41
333	99.45	500	99.48
		750	99.54
		1000	99.57

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

(b) * * *

(2) The efficiency of a liquid-immersed distribution transformer, including submersible distribution transformers, manufactured on or after January 1, 2016, but before January 1, 2027, shall be no less than that required for their kVA rating in the table below. 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.

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	1,000	99.43
667	99.52	1,500	99.48
833	99.55	2,000	99.51
		2,500	99.53

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

(3) The efficiency of a liquid-immersed distribution transformer, that is not a submersible distribution transformer, manufactured on or after January 1, 2027, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.96	15	98.92
15	99.05	30	99.06
25	99.16	45	99.13
37.5	99.24	75	99.22
50	99.29	112.5	99.29
75	99.35	150	99.33
100	99.40	225	99.38
167	99.46	300	99.42
250	99.51	500	99.48
333	99.54	750	99.52
500	99.59	1,000	99.54
667	99.62	1,500	99.58
833	99.64	2,000	99.61
		2,500	99.62
		3,750	99.66
		5,000	99.68

Note: All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test Method for Measuring the Energy Consumption of Distribution Transformers under appendix A to subpart K of 10 CFR part 431.

(4) The efficiency of a submersible distribution transformer, manufactured on or after January 1, 2027, shall be no less than that required for their kVA rating in the table below. 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.

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	1,000	99.43

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
667	99.52	1,500	99.48
833	99.55	2,000	99.51
		2,500	99.53

Note: All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test-Procedure appendix A to subpart K of 10 CFT part 431.

(c) * * *

(2) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after January 1, 2016, but before January 1, 2027, shall be no less than that required for their kVA and BIL rating in the table below. Medium-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.10	97.86		15	97.50	97.18	
25	98.33	98.12		30	97.90	97.63	
37.5	98.49	98.30		45	98.10	97.86	
50	98.60	98.42		75	98.33	98.13	
75	98.73	98.57	98.53	112.5	98.52	98.36	
100	98.82	98.67	98.63	150	98.65	98.51	
167	98.96	98.83	98.80	225	98.82	98.69	98.57
250	99.07	98.95	98.91	300	98.93	98.81	98.69
333	99.14	99.03	98.99	500	99.09	98.99	98.89
500	99.22	99.12	99.09	750	99.21	99.12	99.02
667	99.27	99.18	99.15	1,000	99.28	99.20	99.11
833	99.31	99.23	99.20	1,500	99.37	99.30	99.21
				2,000	99.43	99.36	99.28
				2,500	99.47	99.41	99.33

*BIL means basic impulse insulation level

Note: All efficiency values are at 50 percent of nameplate rated load, determined according to the DOE Test Method for Measuring the Energy Consumption of Distribution Transformers under appendix A to subpart K of 10 CFR part 431.

(3) The efficiency of a medium-voltage dry-type distribution transformer manufactured on or after January 1, 2027, shall be no less than that required for their kVA and BIL rating in the table below. Medium-voltage dry-type distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
15	98.29	98.07		15	97.74	97.45	
25	98.49	98.30		30	98.11	97.86	
37.5	98.64	98.47		45	98.29	98.07	
50	98.74	98.58		75	98.49	98.31	
75	98.86	98.71	98.68	112.5	98.67	98.52	
100	98.94	98.80	98.77	150	98.78	98.66	
167	99.06	98.95	98.92	225	98.94	98.82	98.71
250	99.16	99.05	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	99.23	1,000	99.35	99.28	99.20
833	99.38	99.31	99.28	1,500	99.43	99.37	99.29
				2,000	99.49	99.42	99.35
				2,500	99.52	99.47	99.40

Single-phase				Three-phase			
kVA	BIL			kVA	BIL		
	20–45 kV	46–95 kV	≥96 kV		20–45 kV	46–95 kV	≥96 kV
	Efficiency (%)	Efficiency (%)	Efficiency (%)		Efficiency (%)	Efficiency (%)	Efficiency (%)
				3,750	99.58	99.53	99.47
				5,000	99.62	99.58	99.51

*BIL means basic impulse insulation level

Note: All efficiency values are at 50 percent of nameplate rated load, determined according to the DOE Test Method for Measuring the Energy Consumption of Distribution Transformers under appendix A to subpart K of 10 CFR part 431.

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