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IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

IEEE Power & Energy Society

Sponsored by the
Transformers Committee

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Abstract: General recommendations for loading 65 °C rise mineral-oil-immersed distribution and power transformers are covered.
Keywords: distribution transformer, IEEE C57.91, loading, mineral-oil-immersed, power transformer

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Introduction

This introduction is not part of IEEE Std C57.91-2011, IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators.

This guide is applicable to loading 65 °C mineral-oil-immersed distribution and power transformers. Guides for loading, IEEE Std C57.91-1981 (prior edition), IEEE Std C57.92™-1981,[a] and IEEE Std C57.115-1991 (redesignated as IEEE Std 756) are all combined in this document as the basic theory of transformer loading is the same, whether the subject is distribution transformers, power transformers 100 MVA and smaller, or transformers larger than 100 MVA. In recognition of different types of construction, special considerations, and the degree of conservatism involved in the loading of this equipment, specific sections are devoted to power transformers and distribution transformers. In the previously referenced information, the guide for units larger than 100 MVA referenced the IEEE Std C57.92-1981 loading guide for units up to and including 100 MVA.

This update to the work done in 1995 expands the scope to include step-voltage regulators and replaces Annex A with an improved discussion on bubble evolution. Subclause 8.4 was added for step-voltage regulators. In addition, the formula notations were changed to reflect the updated IEEE style and a number of typographical errors were fixed. Both Clause 7 and Annex G calculation procedures remain in place. Clause J was removed as out-of-date information and is expected to be re-introduced in the future in a new standard on transformer monitoring systems. Annex C and Annex G were changed from normative to informative.

As IEEE Std C57.12.00-2010[b] has adopted an insulation life of 180 000 hours at 110 °C, Table 2 of this guide has been moved to Annex I for historical reference.

In previous guides, different insulation aging curves were used for power transformers and distribution transformers. This was caused by the different evaluation procedures used. The distribution transformer curve was based on aging tests of actual transformers. The power transformer curve was based on aging insulation samples in test containers to achieve 50% retention of tensile strength. Investigation of cellulosic insulating materials removed from transformers that had long service life has led knowledgeable people to question the validity of the 50% criteria. One newer criteria suggested is 25% retention. This guide will permit the user to select the criteria most acceptable to their need, based on percent strength retention, polymerization index, etc. An insulation aging factor may thus be applied.

A per unit life concept and aging acceleration factor are provided in this loading guide. The equations given may be used to calculate percent loss of total insulation life, as has been the practice in earlier editions of the transformer loading guides. The relationship between insulation life and transformer life is a question that remains to be resolved. It is recognized that under the proper conditions, transformer life can well exceed the life of the insulation.

The assumed characteristics used in previous guides contained tables of loading capability based on assumed typical transformer characteristics. These assumed characteristics were recognized as not being those of actually built units, which may have a wide range of characteristics. In this guide these tables were removed since computer technology permits calculation of loading capability based on specific transformer characteristics.

Two methods of calculating temperatures are given in this guide. Clause 7 contains temperature equations similar to those used in previous editions of this guide. These equations use the winding hot spot rise over tank top oil and assume that the oil temperature in the cooling ducts is the same as the tank top oil during overloads. Recent research using imbedded thermocouples and fiber optic detectors indicates that the fluid

[a] IEEE Std C57.92-1981 has been withdrawn; however, copies can be obtained from Global Engineering, 15 Inverness Way East, Englewood, CO 80112-5704, USA, tel. (303) 792-2181 (http://global.ihs.com/).
[b] Information of references can be found in Clause 2.

flow occurring in the windings during transient heating and cooling is an extremely complicated phenomena to describe by simple equations. These recent investigations have shown that during overloads, the temperature of the oil in the winding cooling ducts rises rapidly and exceeds the top-oil temperature in the tank. An alternate set of equations based on this concept is given in Annex G. The change of losses with temperature and liquid viscosity effects, and variable ambient temperature was incorporated into the equations. A computer program based on these equations is given for evaluation by the industry. Research in this field is ongoing at this time and may be incorporated into future revisions of this guide.

Changes in the guide, in addition to the consolidation, include information to more accurately load transformers operating down to a −30 °C ambient, this information concerns loss of diversity due to cold load pick-up or unusually low ambient temperatures.

Transformers rated 55 °C rise were generally replaced as a standard offering by most manufacturers about 1966. Their replacements were originally rated 55/65 °C and in 1977 the single 65 °C rated transformers became the industry standard offering. The higher temperature ratings are based on thermally upgraded oil-paper-enamel insulation systems. Loading of 55 °C insulation system transformers is covered in Annex D.

Suggestions for improvement gained in the use of this guide will be welcomed. They should be sent to the IEEE Standards Department.

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IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

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1. Overview

1.1 Scope

This guide provides recommendations for loading mineral-oil-immersed transformers and step-voltage regulators with insulation systems rated for a 65 °C average winding temperature rise at rated load. This guide applies to transformers manufactured in accordance with IEEE Std C57.12.00[1] and tested in accordance with IEEE Std C57.12.90, and step-voltage regulators manufactured and tested in accordance with IEEE Std C57.15. Because a substantial population of transformers and step-voltage regulators with insulation systems rated for 55 °C average winding temperature rise at rated load are still in service, recommendations that are specific to this equipment are also included.

1.2 Purpose

Applications of loads in excess of nameplate rating involve some degree of risk. It is the purpose of this guide to identify these risks and to establish limitations and guidelines, the application of which will minimize the risks to an acceptable level.

[1] Information of references can be found in Clause 2.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std C57.12.00™, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.[2, 3]

IEEE Std C57.12.90™, IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers.

IEEE Std C57.15™, IEEE Standard Requirements, Terminology, and Test Code for Step-Voltage Regulators.

IEEE Std C57.100™, IEEE Standard Test Procedure for Thermal Evaluation of Insulation Systems for Liquid-Immersed Distribution and Power Transformers.

3. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary: Glossary of Terms and Definitions*[4] should be consulted for terms not defined in this clause.

aging acceleration factor: For a given hottest-spot temperature, the rate at which transformer insulation aging is accelerated compared with the aging rate at a reference hottest-spot temperature. The reference hottest-spot temperature is 110 °C for 65 °C average winding rise and 95 °C for 55 °C average winding rise transformers (without thermally upgraded insulation). For hottest-spot temperatures in excess of the reference hottest-spot temperature, the aging acceleration factor is greater than 1. For hottest-spot temperatures lower than the reference hottest-spot temperature, the aging acceleration factor is less than 1.

directed flow (oil-immersed forced-oil-cooled transformers): The principal part of the pumped insulating fluid from heat exchangers or radiators is forced, or directed, to flow through specific paths in the winding.

non-directed flow (oil-immersed forced-oil-cooled transformers): Indicates that the pumped oil from heat exchangers or radiators flows freely inside the tank, and is not forced to flow through the windings.

percent loss of life: The equivalent aging in hours at the reference hottest-spot temperature over a time period (usually 24 h) times 100 divided by the total normal insulation life in hours at the reference hottest-spot temperature. The equivalent aging in hours at different hot-spot temperatures is obtained by multiplying the aging acceleration factors for the hottest-spot temperatures times the time periods of the various hottest-spot temperatures.

transformer insulation life: For a given temperature of the transformer insulation, the total time between the initial state for which the insulation is considered new and the final state for which dielectric stress, short circuit stress, or mechanical movement, which could occur in normal service, and could cause an electrical failure.

[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA.
[3] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.
[4] *IEEE Standards Dictionary: Glossary of Terms and Definitions* is available at http://shop.ieee.org.

4. Effect of loading beyond nameplate rating

4.1 General

Applications of loads in excess of nameplate rating involve some degree of risk. While aging and long time mechanical deterioration of winding insulation have been the basis for the loading of transformers for many years, it is recognized that there are additional factors that may involve greater risk for transformers of higher megavoltampere and voltage ratings. The risk areas that should be considered when loading large transformers beyond nameplate rating are listed next. Further discussion regarding these risks is provided in Clause 9 or in the annexes, as noted.

a) Evolution of free gas from insulation of winding and lead conductors (insulated conductors) heated by load and eddy currents (circulating currents between or within insulated conductor strands) may jeopardize dielectric integrity. See Annex A for further discussion.

b) Evolution of free gas from insulation and insulating fluid adjacent to metallic structural parts linked by electromagnetic flux produced by winding or lead currents may also reduce dielectric strength.

c) Loss of life calculations may be made as described in Clause 5. If a percent loss of total life calculation is made based on an arbitrary definition of a “normal life” in hours, one should recognize that the calculated results may not be as conservative for transformers rated above 100 MVA as they are for smaller units since the calculation does not consider mechanical wear effects that may increase with megavoltampere rating.

d) Operation at high temperature will cause reduced mechanical strength of both conductor and structural insulation. These effects are of major concern during periods of transient overcurrent (through-fault) when mechanical forces reach their highest levels.

e) Thermal expansion of conductors, insulation materials, or structural parts at high temperatures may result in permanent deformations that could contribute to mechanical or dielectric failures.

f) Pressure build-up in bushings for currents above rating could result in leaking gaskets, loss of oil, and ultimate dielectric failure. See Annex B for further discussion.

g) Increased resistance in the contacts of tap changers can result from a build-up of oil decomposition products in a very localized high temperature region at the contact point when the tap changer is loaded beyond its rating. In the extreme, this could result in a thermal runaway condition with contact arcing and violent gas evolution. See Annex B for further discussion.

h) Auxiliary equipment internal to the transformer, such as reactors and current transformers, may also be subject to some of the risk identified above. See Annex B for further discussion.

i) When the temperature of the top oil exceeds 105 °C (65 °C rise over 40 °C ambient according to IEEE Std C57.12.00), there is a possibility that oil expansion will be greater than the holding capacity of the tank and also result in a pressure that causes the pressure relief device to operate and expel the oil. The loss of oil may also create problems with the oil preservation system or expose electrical parts upon cooling.

4.2 Voltage and frequency considerations

Voltage and frequency influences should be recognized when determining limitations for loading a transformer beyond its nameplate rating. This is true even though in all probability there may be little control of these parameters during a loading beyond nameplate rating event. IEEE Std C57.12.00 defines the capability of a transformer to operate above rated voltage and below rated frequency. The user of this guide should recognize that, during conditions of loading beyond nameplate, the voltage regulation through the transformer may increase significantly (depending on the transformer impedance) due to the increased kilovoltampere loading and possibly dropping power factor.

A conservative guideline to prevent excessive core heating due to increased excitation is to reduce the transformer output volts per hertz limit by 1% for every 1% increase in voltage regulation during the loading beyond nameplate event. For example, if the voltage regulation at rated conditions is 6% and increases to 9% at some load above nameplate, the output volts per hertz limit might be reduced from 105% to 102%.

4.3 Supplemental cooling of existing self-cooled transformers

The load that can be carried on existing self-cooled transformers can usually be increased by adding auxiliary cooling equipment such as fans, external forced-oil coolers, or water spray equipment. The amount of additional loading varies widely, depending upon the following:

a) Design characteristics of the transformer
b) Type of cooling equipment
c) Permissible increase in voltage regulation
d) Limitations in associated equipment

No general rules can be given for such supplemental cooling, and each transformer should be considered individually.

The use of water spray equipment for supplemental cooling is not recommended for use in normal loading beyond nameplate rating. Appropriate precautions should be made for application of water spray equipment for supplemental cooling during emergency overloads. The major problem is the build up of scale on the cooling equipment due to minerals in the water. Over the long term this buildup will hinder the cooling efficiency. The spray and steam generated can also cause phase-to-phase flashover between bushings.

4.4 Information for user calculations

If the user intends to perform calculations to determine the loading capability of a transformer using Clause 7 or Annex G, the user should request the following minimum information in the specification or final test report:

a) Top-oil temperature rise over ambient temperature at rated load
b) Bottom-oil temperature rise over ambient temperature at rated load
c) Average conductor temperature rise over ambient temperature at rated load
d) Winding hottest-spot temperature rise over ambient temperature at rated load
e) Load loss at rated load
f) No-load (core) loss
g) Total loss at rated load
h) Confirmation of oil flow design (that is, directed or non-directed)
i) Weight of core and coil assembly
j) Weight of tank and fittings

   NOTE—For the purpose of transient thermal calculations, the weight of tank and fittings to be used are only those portions that are in contact with heated oil.[5]

k) Volume of oil in the tank and cooling equipment (excluding LTC compartments, oil expansion tanks, etc.)

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[5] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

For all of the information in a) through g), the conditions under which the measurements were made (load, ambient temperature, tap, etc.) should be stated. If test data from thermally similar units is supplied the data shown on the test report should be corrected (in accordance with IEEE recommended procedures when issued) by the manufacturer using the actual design characteristics (losses, cooling surface, etc.) of the transformer supplied.

More precise calculations of loading capability may be performed if desired using Clause 7 or Annex G if the following additional information is provided:

— Load loss at rated load at rated and tap extremes or all possible tap connection combinations
— Winding resistance at tap extremes or all possible tap combinations

More precise calculations of loading capability may be performed if desired using Annex G if the following additional information is also provided:

— Total stray and eddy loss as a percent of total load loss and estimated stray and eddy loss
— Per unit eddy loss at hot spot location
— Per unit winding height to hot spot location

The temperature rise test is performed (and calculations of temperature rises made when a test is not performed) on the maximum loss tap position. This data results in conservative predictions of loading capability when the transformer is operated on other than the maximum loss tap. To achieve more accurate predictions of the capability of a transformer based on the actual loading cycle and tap connections, several adjustments may be made of the data presented in the test report before the data is used as input to loading calculations. These adjustments are provided in the following:

— Load cycle in kVA on the actual combination of tap connections
— Use the measured or calculated load losses for that tap connection
— Correct the temperature rise test data for the lower losses or different rated current
— Determine if the hottest-spot winding gradient changes with changes in the tap connections

Calculating the effect of load tap changer operation into the loading predictions is an extremely complicated and controversial subject and the effect may vary with manufacturer. For some designs the effect of load tap changer operation may have a negligible effect on temperature rises of the transformer windings.

5. Transformer insulation life

5.1 General

The subject of loss of transformer insulation life has had a rich but controversial history of development, with distribution and power transformers taking independent research paths (refer to I.1 in Annex I). As a result of recent study and testing, the approach to determination of insulation loss of life in this guide has been significantly modified (refer to I.2 in Annex I.) Aging or deterioration of insulation is a time function of temperature, moisture content, and oxygen content. With modern oil preservation systems, the moisture and oxygen contributions to insulation deterioration can be minimized, leaving insulation temperature as the controlling parameter. Since, in most apparatus, the temperature distribution is not uniform, the part that is operating at the highest temperature will ordinarily undergo the greatest deterioration. Therefore, in aging studies it is usual to consider the aging effects produced by the highest (hottest-spot) temperature.

Because many factors influence the cumulative effect of temperature over time in causing deterioration of transformer insulation, it is not possible to predict with any great degree of accuracy the useful life of the insulation in a transformer, even under constant or closely controlled conditions, much less under widely varying service conditions. Wherever the word “life” is used in this guide, it means calculated insulation life, not actual transformer life.

5.2 Aging equations

Experimental evidence indicates that the relation of insulation deterioration to time and temperature follows an adaptation of the Arrhenius reaction rate theory that has the following form:

$$\text{Per Unit Life} = A\,\mathrm{e}^{\left[\frac{B}{\Theta H + 273}\right]}$$

where

Θ_H is the winding hottest-spot temperature, °C
A is a constant
B is a constant
e is the base of the natural logarithm

The transformer per unit insulation life curve of Figure 1 relates per unit transformer insulation life to winding hottest-spot temperature. This curve should be used for both distribution and power transformers because both are manufactured using the same cellulose conductor insulation. The use of this curve isolates temperature as the principal variable affecting thermal life. It also indicates the degree to which the rate of aging is accelerated beyond normal for temperature above a reference temperature of 110 °C and is reduced below normal for temperature below 110 °C (see discussion in I.2 of Annex I). The equation for the curve is as follows:

$$\text{Per Unit Life} = 9.8 \times 10^{-18}\,\mathrm{e}^{\left[\frac{15000}{\Theta H + 273}\right]} \tag{1}$$

where

Θ_H is the winding hottest-spot temperature, °C

The per unit transformer insulation life curve (Figure 1) can be used in the following two ways. It is the basis for calculation of an aging acceleration factor (F_{AA}) for a given load and temperature or for a varying load and temperature profile over a 24 h period. A curve of F_{AA} vs. hottest-spot temperature for a 65 °C rise insulation system is shown in Figure 2 and values are tabulated in Table 1. F_{AA} has a value greater than 1 for winding hottest-spot temperatures greater than the reference temperature 110 °C and less than 1 for temperatures below 110 °C. The equation for F_{AA} is as follows:

$$F_{AA} = \mathrm{e}^{\left[\frac{15000}{383} - \frac{15000}{\Theta H + 273}\right]} \tag{2}$$

where

F_{AA} is the aging acceleration factor
Θ_H is the winding hottest-spot temperature, °C

Equation (2) may be used to calculate equivalent aging of the transformer. The equivalent aging factor at the reference temperature in a given time period for the given temperature cycle is the following:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} \tag{3}$$

where

F_{EQA} is equivalent aging factor for the total time period
$F_{AA,n}$ is aging acceleration factor for the temperature that exists during the time interval Δt_n
n is index of the time interval, Δt
N is total number of time intervals
Δt_n is time interval, h

See Annex I for example calculations.

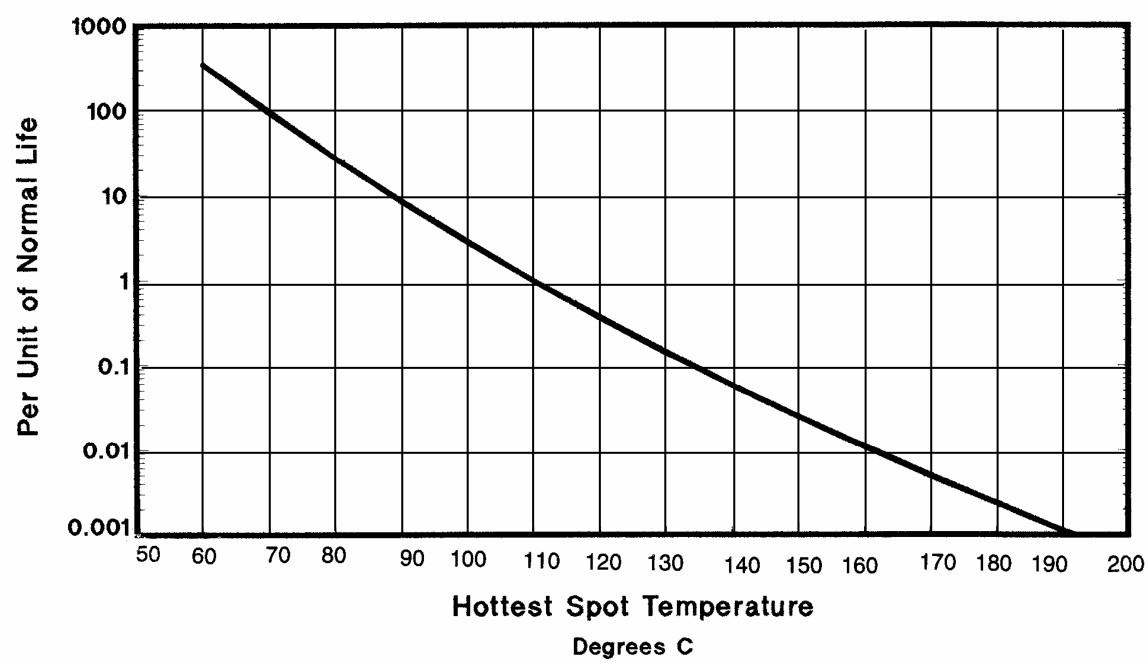

Figure 1— Transformer insulation life

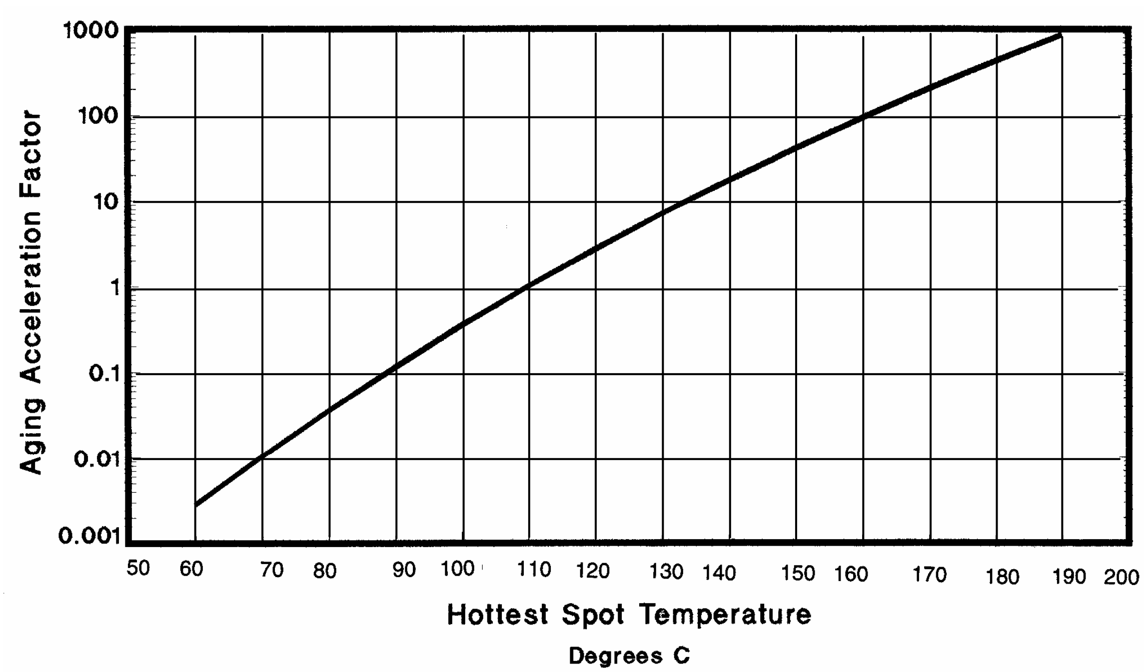

Figure 2— Aging acceleration factor (relative to 110 °C)

Table 1—Aging acceleration factor

Temperature °C	Age factor	Temperature °C	Age factor	Temperature °C	Age factor
<37	0.0000	91	0.1295	146	28.9315
37	0.0001	92	0.1449	147	31.5115
38	0.0001	93	0.1622	148	34.3015
39	0.0001	94	0.1813	149	37.3215
40	0.0002	95	0.2026	150	40.5915
41	0.0002	96	0.2263	151	44.1315
42	0.0002	97	0.2526	152	47.9615
43	0.0002	98	0.2817	153	52.1015
44	0.0003	99	0.3141	154	56.5815
45	0.0003	100	0.3499	155	61.4215
46	0.0004	101	0.3897	156	66.6516
47	0.0004	102	0.4337	157	72.3016
48	0.0005	103	0.4823	158	78.3916
49	0.0006	104	0.5362	159	84.9716
50	0.0007	105	0.5957	160	92.0616
51	0.0008	106	0.6614	161	99.7116
52	0.0009	107	0.7340	162	107.9616
53	0.0011	108	0.8142	163	116.8416
54	0.0012	109	0.9026	164	126.4116
55	0.0014	110	1.0000	165	136.7216
56	0.0016	111	1.1074	166	147.8117
57	0.0019	112	1.2256	167	159.7517
58	0.0021	113	1.3558	168	172.5817
59	0.0024	114	1.4990	169	186.3917
60	0.0028	115	1.6565	170	201.2317
61	0.0032	116	1.8296	171	217.1817
62	0.0037	117	2.0197	172	234.3017
63	0.0042	118	2.2285	173	252.7017
64	0.0048	119	2.4576	174	272.4517
65	0.0054	120	2.7089	175	293.6417
66	0.0062	121	2.9845	176	316.3718
67	0.0071	122	3.2865	177	340.7518
68	0.0080	123	3.6172	178	366.8918
69	0.0091	124	3.9793	179	394.9118
70	0.0104	125	4.3756	180	424.9218
71	0.0118	126	4.8091	181	457.0718
72	0.0134	127	5.2830	182	491.5018
73	0.0152	128	5.8009	183	528.3518
74	0.0172	129	6.3665	184	567.7818
75	0.0195	130	6.9842	185	609.9618
76	0.0220	131	7.6582	186	655.0819
77	0.0249	132	8.3935	187	703.3119
78	0.0281	133	9.1952	188	754.8619
79	0.0318	134	10.0689	189	809.9419
80	0.0358	135	11.0208	190	868.7719
81	0.0404	136	12.0573	191	931.6019
82	0.0455	137	13.1856	192	998.6719
83	0.0513	138	14.4131	193	1070.2519
84	0.0577	139	15.7481	194	1146.6219
85	0.0649	140	17.1994	195	1228.0819
86	0.0729	141	18.7765	196	1314.9420
87	0.0819	142	20.4895	197	1407.5420
88	0.0919	143	22.3493	198	1506.2220
89	0.1031	144	24.3679	199	1611.3520
90	0.1156	145	26.5578	200	1723.3420

5.3 Percent loss of life

The insulation per unit life curve (see Figure 1) can also be used to calculate percent loss of total life, as has been the practice in earlier editions of the referenced transformer loading guides. To do so, it is necessary to arbitrarily define the normal insulation life at the reference temperature in hours or years. Benchmark values of normal insulation life for a well-dried, oxygen-free system can be selected from Table I.2. Then the hours of life lost in the total time period is determined by multiplying the equivalent aging determined in Equation (3) by the time period (t) in hours. This gives equivalent hours of life at the reference temperature that are consumed in the time period. Percent loss of insulation life in the time period is equivalent hours life consumed divided by the definition of total normal insulation life (h) and multiplied by 100. Usually the total time period used is 24 h. The equation is given as follows:

$$\%\ \text{Loss of life} = \frac{F_{EQA} \times t \times 100}{\text{Normal insulation life}} \tag{4}$$

where

F_{EQA} is equivalent aging factor for the total time period

Per 5.11.3 of IEEE Std C57.12.00-2010, a minimum normal insulation life expectancy of 180 000 hours is required. Other values for the end of life criteria have been used historically for developing transformer loading capability studies. The equations provided in this clause include a variable for the end of life criteria, so those users who have used alternative values may continue to do so. The end of life criteria are described in Table I.2 of Annex I.

The time duration for continuous operation at hottest-spot temperatures above rated that give different percent loss of life may be calculated using Equation (4). Table 2 gives time durations for various loss of life based on a normal life of 180 000 h. Normal percent loss of life for operation at a rated hottest-spot temperature of 110 °C for 24 h is 0.0133%.

Table 2—Time durations in hours for continuous operation above rated hottest-spot temperature for different loss of life values

Hot spot temp °C	F_{AA}	Percent loss of life[a]						
		0.0133[b]	0.02	0.05	0.1	0.2	0.3	0.4
110	1.00	24	—	—	—	—	—	—
120	2.71	8.86	13.3	—	—	—	—	—
130	6.98	3.44	5.1	12.9	—	—	—	—
140	17.2	1.39	2.1	5.2	10.5	20.9	—	—
150	40.6	0.59	0.89	2.2	4.4	8.8	13.3	17.7
160	92.1	0.26	0.39	0.98	1.96	3.9	5.9	7.8
170	201.2	0.12	0.18	0.45	0.89	1.8	2.7	3.6
180	424.9	0.06	0.08	0.21	0.42	0.84	1.27	1.7
190	868.8	0.028	0.04	0.10	0.21	0.41	0.62	0.82
200	1723	0.014	0.02	0.05	0.10	0.21	0.31	0.42

[a] Based on a normal life of 180 000 h. Time durations not shown are in excess of 24 h.
[b] This column of time durations for 0.0133% loss of life gives the hours of continuous operation above the basis-of-rating hottest-spot temperature (110 °C) for one equivalent day of operation at 110 °C.

6. Ambient temperature and its influence on loading

6.1 General

Ambient temperature is an important factor in determining the load capability of a transformer since the temperature rises for any load must be added to the ambient to determine operating temperatures. Transformer ratings are based on a 24 h average ambient of 30 °C. This is the standard ambient used in this guide. Whenever the actual ambient can be measured, such ambients should be averaged over 24 h, and then used in determining the transformer's temperature and loading capability. The ambient air temperature seen by a transformer is the air in contact with its radiators or heat exchangers. In some installations the transformer may be outdoors but surrounded by buildings or sound deadening walls. This may result in recirculation of air, and the ambient should be adjusted accordingly.

6.2 Approximating ambient temperature for air-cooled transformers

It is often necessary to predict the load that a transformer can safely carry at some future time in an unknown ambient. The probable ambient temperature for any month may be approximated from data in reports prepared by the national or local atmospheric authority for the sections of the country where the transformer is located.

a) *Average temperature*. Use average daily temperature for the month involved, averaged over several years.
b) *Maximum daily temperature*. Use average of the maximum daily temperatures for month involved averaged over several years.

These ambients should be used as follows:

— For loads with normal life expectancy, use a), the average temperature as the ambient for the month involved.

— For short-time loads with moderate sacrifice of life expectancy, use b), the maximum daily temperature for the month involved.

During any one day the 24 h average of temperature may exceed the value derived from a) or b) above. To be conservative it is recommended that these temperatures be increased by 5 °C since aging at higher than average temperature is not fully compensated by decreased aging at lower than average temperature. With this margin the approximated 24 h average temperature will not be exceeded on more than a few days per month and, where it is exceeded, the additional loss of life will not be serious.

6.3 Approximating ambient temperature for water-cooled transformers

The ambient temperature to be used for water-cooled transformers is the cooling water temperature plus an added 5 °C to allow for possible loss of cooling efficiency due to deposits on cooling coil surfaces of water-cooled transformers in service.

6.4 Influence of ambient on loading for normal life expectancy

Average ambient temperatures should cover 24 h time periods. The associated maximum temperatures should not be more than 10 °C above the average temperatures for air-cooled, and 5 °C for water-cooled transformers. Since ambient temperature is an important factor in determining the load capability of a transformer, it should be controlled for indoor installations by adequate ventilation and should always be considered in outdoor installations.

Table 3 gives the increase or decrease from rated kVA for other than average daily ambients of 30 °C for air and 25 °C for water. It is recommended that a 5 °C margin be used when applying the factors from Table 3. It should be pointed out that the increase or decrease obtained from Table 3 is conservative, and therefore do not check exactly with calculations using the equations in Clause 7. Table 3 is for quick approximations, only. Loading on the basis of ambient temperature with loads permitted in Table 3 will give approximately the same life expectancy as if transformers were operated at nameplate rating and standard ambient temperatures over the same period. Table 3 covers a range in average ambient temperatures of –30 °C to 50 °C for cooling air. A check should be made with the manufacturer before loading on the basis of ambient air less than –30 °C or greater than 50 °C.

Table 3—Loading on basis of temperatures (average ambient other than 30 °C and average winding rise less than limiting values) (for quick approximation) (ambient temperature range –30 °C to 50 °C)

Type of cooling	% of kVA rating	
	Decrease load for each °C higher temperature	Increase load for each °C lower temperature
Self-cooled—ONAN	1.5	1.0
Water-cooled—ONWF	1.5	1.0
Forced-air-cooled—ONAN/ONAF, ONAN/ONAF/ONAF	1.0	0.75
Forced-oil, -air, -water-cooled—OFAF, OFWF, ODWF, and ONAN/OFAF/OFAF	1.0	0.75

7. Calculation of temperatures

7.1 Load cycles

7.1.1 Load cycles, general

Transformers usually operate on a load cycle that repeats every 24 h. A typical normal load cycle, such as shown in Figure C.1 of Annex C, consists of load fluctuations throughout the day. For normal loading or planned overloading above nameplate, a multi-step load cycle calculation method is usually used. The 24 h load profile is described by a series of constant loads of a short duration (usually 1/2 h or 1 h). The equivalent load during the short time steps may be determined by the method of 7.1.2 or by using the maximum peak load during the short-time period under consideration. This method is usually used in computer programs.

An equivalent two step overload cycle as shown in Figure 3 may be used for determining emergency overload capability using the Equation (5) through Equation (22). The equivalent two-step load cycle consists of a prior load and a peak load. This figure is also used for the purpose of describing calculations to determine equivalent load cycles. There is usually one period in the daily load cycle when the load builds up to a considerably greater value than any reached at other times, such as shown by the solid line in the overload cycle in Figure 3. Generally, the maximum value or peak load is not reached and passed suddenly, but builds up and falls off gradually. Calculations using the multi-step load cycle described in the previous paragraph may also be performed for emergency overload cycles if desired.

7.1.2 Method of converting actual to equivalent load cycle

A transformer supplying a fluctuating load generates a fluctuating loss, the effect of which is about the same as that of an intermediate constant load for the same period of time. This is due to the heat storage characteristics of the materials in the transformer. A constant load that generates the same total losses as a fluctuating load is assumed an equivalent load from a temperature standpoint. Equivalent load for any part of a daily load cycle may be expressed by Equation (5).

$$\left[\frac{L_1^2 t_1 + L_2^2 t_2 + L_3^2 t_3 + \ldots\ldots + L_N^2 t_N}{t_1 + t_2 + t_3 + \ldots\ldots + t_N}\right]^{0.5} \tag{5}$$

where

$L_1, L_2, \ldots$ is various load steps in %, per unit, or in actual kVA or current
N is the total number of loads considered
$t_1, t_2, \ldots$ is the respective durations of these loads, h

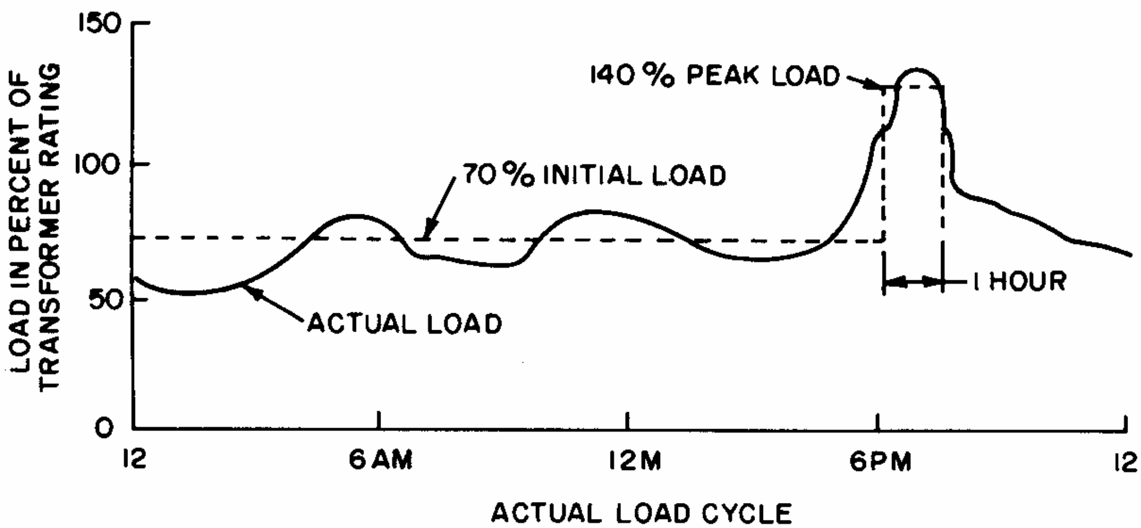

Figure 3—Example of actual load cycle and equivalent load cycle

7.1.3 Equivalent peak load

Equivalent peak load for the usual load cycle is the rms load obtained by Equation (5) for the limited period over which the major part of the actual irregular peak seems to exist. The estimated duration of the peak has considerable influence over the rms peak value. If the duration is over-estimated, the rms peak value may be considerably below the maximum peak demand. To guard against overheating due to high, brief overloads during the peak overload, the rms value for the peak load period should not be less than 90% of the integrated 1/2 h maximum demand.

7.1.4 Equivalent continuous prior load

The equivalent continuous prior load is the rms load obtained by Equation (5) over a chosen period of the day. Experience indicates that quite satisfactory results are obtained by considering the 12 h periods preceding and following the peak and by selecting the larger of the two rms values so produced. Time intervals (t) of 1 h are suggested as a further simplification of the equation, which for a 12 h period becomes Equation (6). The dashed line in Figure 3 shows the equivalent load cycle constructed from the actual load cycle.

$$\text{Equivalent continuous 12 h prior load} = 0.29\left[L_1^2 + L_2^2 + \ldots\ldots + L_{12}^2\right]^{0.5} \tag{6}$$

where

L_1, L_2,... is various load steps in %, per unit, or in actual kVA or current

7.2 Calculation of temperatures

7.2.1 General

The method given here for calculation of oil and winding temperatures for changes in load requires no iterative procedures. The exponents, *m* and *n,* approximately account for changes in load loss and oil viscosity caused by changes in temperature. Values for the exponents used in these equations are shown in Table 4. Exact values of the exponents for specific transformers may be determined by overload test procedures in IEEE Std C57.119 [G6].[6]

An alternate method, which requires computer calculation procedures, is given in Annex G. This method is more exact in accounting for changes in load loss and oil viscosity caused by changes in resistance and oil temperature, respectively. The effect of a variable ambient temperature is also considered. This method should produce a greater accuracy in loading capability if accurate methods of determining load, ambient temperature, tap position, and the cooling mode in operation are utilized.

7.2.2 Components of temperature

The hottest-spot temperature is assumed to consist of three components given by the following equation:

$$\Theta_H = \Theta_A + \Delta\Theta_{TO} + \Delta\Theta_H \tag{7}$$

where

Θ_H is the winding hottest-spot temperature, °C
Θ_A is the average ambient temperature during the load cycle to be studied, °C
$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_H$ is the winding hottest-spot rise over top-oil temperature, °C

The top-oil temperature is given by the following equation:

$$\Theta_{TO} = \Theta_A + \Delta\Theta_{TO} \tag{8}$$

where

Θ_{TO} is the top-oil temperature, °C
Θ_A is the average ambient temperature during the load cycle to be studied, °C
$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

[6] The numbers in brackets combined with the letter "G" correspond to those of the bibliography in Annex G.

The temperature calculations assume a constant ambient temperature. The effect of a variable ambient may be conservatively considered as follows:

a) For ambient temperatures that increase during the load cycle, the instantaneous ambient should be used when considering load cycles.

b) For decreasing ambient temperatures, the maximum ambient during a long prior cycle of about 12 h should be used.

7.2.3 Top-oil rise over ambient

The top-oil temperature rise at a time after a step load change is given by the following exponential expression containing an oil time constant:

$$\Delta\Theta_{TO} = (\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i})\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i} \tag{9}$$

where

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C
exp is the base of natural logarithm
τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

For the two-step overload cycle with a constant equivalent prior load the initial top-oil rise is given by the following:

$$\Delta\Theta_{TO,i} = \Delta\Theta_{TO,R}\left[\frac{(K_i^2 R + 1)}{(R+1)}\right]^n \tag{10}$$

where

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C
K_i is the ratio of initial load L to rated load, per unit
n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

For the multi-step load cycle analysis with a series of short-time intervals, Equation (9) is used for each load step, and the top-oil rise calculated for the end of the previous load step is used as the initial top-oil rise for the next load step calculation.

The ultimate top-oil rise is given by the following equation:

$$\Delta\Theta_{TO,U} = \Delta\Theta_{TO,R}\left[\frac{(K_U^2 R+1)}{(R+1)}\right]^n \tag{11}$$

where

$\Delta\Theta_{TO,R}$	is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C
$\Delta\Theta_{TO,U}$	is the ultimate top-oil rise over ambient temperature for load L, °C
K_U	is the ratio of ultimate load L to rated load, per unit
n	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
R	is the ratio of load loss at rated load to no-load loss on the tap position to be studied

Equation (11) is used to calculate the ultimate oil rise for each load step. Except for very long duration constant loads, the ultimate top-oil rise calculated by Equation (11) is never reached.

7.2.4 Oil time constant

The thermal capacity is given by the following equation for the ONAN and ONAF cooling modes:

$C =$ 0.1326 (weight of core and coil assembly in kilograms) (12A)
+ 0.0882 (weight of tank and fittings in kilograms)
+ 0.3513 (liters of oil)

or

$C =$ 0.06 (weight of core and coil assembly in pounds) (12B)
+ 0.04 (weight of tank and fittings in pounds)
+ 1.33 (gallons of oil)

The derivation of the exponential heating equation is based on the average temperature rise of the lumped mass. In the case of the transformer this would be the average oil temperature. However, the top oil is the variable measured by temperature indicators or thermocouples during thermal tests. In Equation (12A) for the thermal capacity, two-thirds of the weight of the tank and 86% of the specific heat of the oil was used.

For forced-oil cooling modes either directed or non-directed the thermal capacity is given by the following:

$C =$ 0.1323 (weight of core and coil assembly in kilograms) (13A)
+ 0.1323 (weight of tank and fittings in kilograms)
+ .5099 (liters of oil)

or

$C =$ 0.06 (weight of core and coil assembly in pounds) (13B)
+ 0.06 (weight of tank and fittings in pounds)
+ 1.93 (gallons of oil)

For the calculation of the time constant, the weight of the tank and fittings to be used is only those portions that are in contact with heated oil. Some transformers may have cabinetry and tank base construction with substantial weight that does not contribute to the thermal mass in determination of the oil rise time constant.

The top-oil time constant at rated kVA is given by the following:

$$\tau_{TO,R} = \frac{C\,\Delta\Theta_{TO,R}}{P_{T,R}} \tag{14}$$

where

C is the thermal capacity of the transformer, W-h/°C
$P_{T,R}$ is the total loss at rated load, W
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C
$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

The top-oil time constant is

$$\tau_{TO} = \tau_{TO,R}\,\frac{\left(\dfrac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}}\right) - \left(\dfrac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}\right)}{\left(\dfrac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}} - \left(\dfrac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}}} \tag{15}$$

where

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h
$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

In the derivation of Equation (9) it was assumed that the top-oil temperature rise $\Delta\Theta_{TO}$ is directly proportional to the heat loss *q,* or in equation form,

$$\Delta\Theta_{TO} = Kq^{n}$$

where

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
K is the ratio of load L to rated load, per unit
q is the heat loss, W
$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

If the exponent n = 1.0, the time constant given by Equation (14) and the exponential Equation (9) is correct for any load and any starting temperature. If n is less than 1, the equation is incorrect and the time constant must be modified as shown in Equation (15) for different overload cycles. Equation (15) was developed to give a corrected time constant (for case of $n < 1$) to use in the exponential equation that gave the same rate of change of initial temperature rise and the same final temperature rise if the overload continued indefinitely; however, intermediate temperatures may vary somewhat from actual.

If n is equal to 1.0, 63% of the temperature change occurs in a length of time equal to the time constant regardless of the relationship of initial temperature rise and ultimate temperature rise. If n is not unity, the temperature change in a similar time interval will be different, depending on both initial temperature rise and ultimate temperature rise.

7.2.5 Winding hot-spot rise

Transient winding hottest-spot temperature rise over top-oil temperature is given by

$$\Delta\Theta_H = (\Delta\Theta_{H,U} - \Delta\Theta_{H,i})\left(1 - e^{-\frac{t}{\tau_w}}\right) + \Delta\Theta_{H,i} \tag{16}$$

where

t	is the duration of load, h
$\Delta\Theta_H$	is the winding hottest-spot rise over top-oil temperature, °C
$\Delta\Theta_{H,U}$	is the ultimate winding hottest-spot rise over top-oil temperature for load L, °C
$\Delta\Theta_{H,i}$	is the initial winding hottest-spot rise over top-oil temperature for $t = 0$, °C
τ_W	is the winding time constant at hot spot location, h

The initial hot-spot rise over top oil is given by

$$\Delta\Theta_{H,i} = \Delta\Theta_{H,R} K_i^{2m} \tag{17}$$

where

K_i	is the ratio of initial load L to rated load, per unit
m	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.
$\Delta\Theta_{H,i}$	is the initial winding hottest-spot rise over top-oil temperature for $t = 0$, °C
$\Delta\Theta_{H,R}$	is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

The ultimate hot-spot rise over top oil is given by

$$\Delta\Theta_{H,U} = \Delta\Theta_{H,R} K_u^{2m} \tag{18}$$

where

K_U is the ratio of ultimate load L to rated load, per unit
m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.
$\Delta\Theta_{H,U}$ is the ultimate winding hottest-spot rise over top-oil temperature for load L, °C
$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

The rated value of hot-spot rise over top oil is given by

$$\Delta\Theta_{H,R} = \Delta\Theta_{H/A,R} - \Delta\Theta_{TO,R} \tag{19}$$

where

$\Delta\Theta_{H/A,R}$ is the winding hot spot rise over ambient at rated load on the tap position to be studied, °C
$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

The value of the winding hot-spot rise over ambient $\Delta\Theta_{H/A,R}$ is obtained in the following manner, in order of preference:

— By actual test using imbedded detectors
— Calculated value supplied by manufacturer on test report, or
— Assume $\Delta\Theta_{H/A,R}$ = 80 °C for 65 °C average winding rise and 65 °C for 55 °C average winding rise

The value of the top-oil rise over ambient $\Delta\Theta_{TO,R}$ is determined by

— Actual test per IEEE Std C57.12.90, or
— Calculated value supplied by the manufacturer on the test report

The winding time constant is the time it takes the winding temperature rise over oil temperature rise to reach 63.2% of the difference between final rise and initial rise during a load change. The winding time constant may be estimated from the resistance cooling curve during thermal tests or calculated by the manufacturer using the mass of the conductor materials. The winding time constant varies with the oil viscosity and the exponent m. For moderate overloads it is conservative to neglect the winding time constant and assume the winding hot-spot rise over top oil is given by Equation (18).

7.2.6 Exponents for temperature rise equations

The suggested exponents for use in the temperature rise equations are given in Table 4.

Table 4—Exponents used in temperature determination equations [a]

Type of cooling	*m*	*n*
ONAN	0.8	0.8
ONAF	0.8	0.9
Non-directed OFAF or OFWF	0.8	0.9
Directed ODAF or ODWF	1.0	1.0

[a] Other values of exponents may be used if substantiated by design and test data.

7.2.7 Adjustment of test data for different tap position

If it is desired to adjust the test report data for operation on a no-load tap position other than that reported on the test report, the following equations may be used. The prime symbol (') indicates values at the different tap position.

Top-oil rise over ambient:

$$\Delta \Theta'_{TO,R} = \Delta \Theta_{TO,R} \left[\frac{P'_{T,R}}{P_{T,R}} \right]^n \tag{20}$$

where

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
$P_{T,R}$ is the total loss at rated load, W
$P'_{T,R}$ is the total loss at rated load on a different tap position, W
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C
$\Delta\Theta'_{TO,R}$ is the top-oil rise over ambient temperature at rated load on a different tap position, °C

Hottest spot rise over top oil:

$$\Delta\,\Theta'_{H,R} = \Delta\,\Theta_{H,R}\left[\frac{I'_R}{I_R}\right]^{2m} \tag{21}$$

where

I_R	is rated current
I'_R	is rated current for a different tap position
m	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.
$\Delta\Theta_{H,R}$	is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C
$\Delta\Theta'_{H,R}$	is the winding hottest-spot rise over top-oil temperature at rated load on a different tap position, °C

Time constant at rated load:

$$\tau'_{TO,R} = \frac{C\,\Delta\Theta_{TO,R}}{P'_{T,R}} \tag{22}$$

where

C	is the thermal capacity of the transformer, W-h/°C
$P'_{T,R}$	is the total loss at rated load on a different tap position, W
$\Delta\Theta_{TO,R}$	is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C
$\tau'_{TO,R}$	is the time constant for rated load for a different tap position beginning with initial top-oil temperature rise of 0 °C, h

7.3 Computer calculation of loading capability

Due to the wide variations in transformer characteristics typical loading capability tables are not published in this guide. The equations given in Clause 5 and Clause 7 may be used to develop a computer program that calculates the loading capability for a specific transformer design. A suggested flow chart is shown in Table 4. The program should compute and print the maximum peak load that can be impressed on a transformer and meet specified limitations. In addition, the computer program should calculate the top-oil and hottest-spot temperatures as a function of time for a repetitive 24 h load cycle. The total loss of insulation life for a 24 h load cycle should also be calculated.

Input to the program should consist of the following:

a) Transformer characteristics (loss ratio, top-oil rise, bottom-oil rise, hottest-spot rise, total loss, gallons of oil, weight of tank and fittings) (all at rated load)

b) Ambient temperatures

c) Initial continuous load

d) Peak load durations and the specified daily percent loss of life

e) Repetitive 24 h load cycle if desired

A systematic convergence process may be used to obtain the highest allowable peak load. An initial trial is made with an assumed peak load midway between the minimum continuous load and maximum permitted peak load (300% for distribution transformers, 200% for power transformers). Using this peak load, aging calculations are made at varying time intervals (depending on the time duration of the peak load) during the 24 h, to determine the total daily insulation aging imposed by the load cycle. A comparison is made between the calculated values and the limiting values, (top-oil temperature, hot-spot temperature, or specified percent loss of life). Depending on the results, the peak value is changed and the calculation repeated until the calculated value of the total percent loss of life above normal is within ±4% of the desired value. At this point, the peak load and corresponding values of peak hottest-spot temperature, peak top-oil temperature, total percent loss of life, and the specified percent loss of life are printed out.

7.4 Bibliography for Clause 7

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[4] Montsinger, V. M. and Ketchum, P.M., *Emergency Overloading of Air Cooled Oil-Immersed Power Transformers*, AIEE Transactions, vol. 61, pp. 906–916, 993–995, 1942.

[5] Narbutovskih, P., *Simplified Graphical Method of Computing Thermal Transients*, AIEE Transactions, vol. 66, pp. 78–83, 1947.

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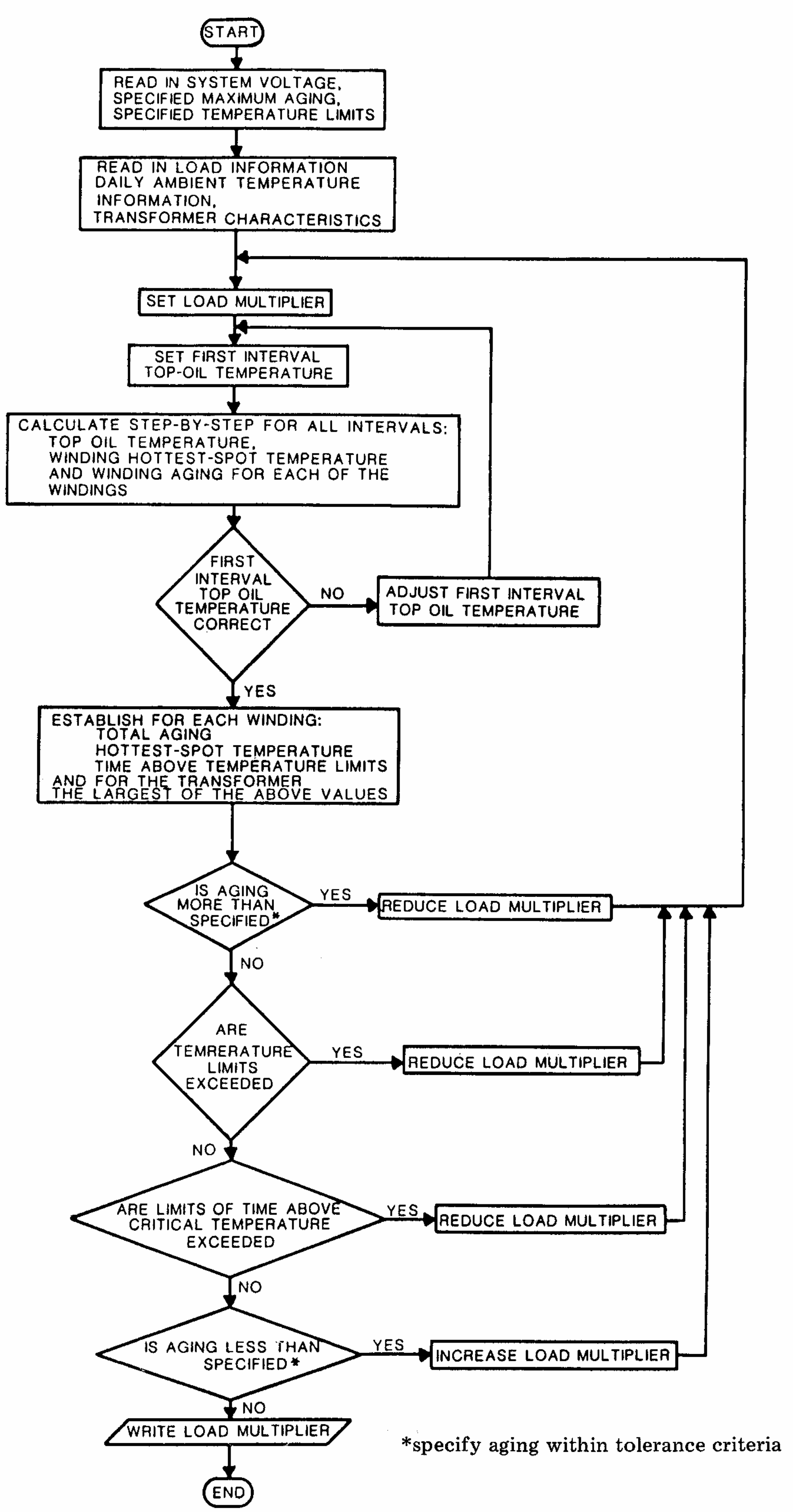


Figure 4—Logic diagram for computer program

8. Loading of distribution transformers and step-voltage regulators

8.1 Life expectancy

8.1.1 General

Distribution transformer and voltage regulator life expectancy at any operating temperature is not accurately known. The information given regarding loss of insulation life at elevated temperatures is considered to be conservative and the best that can be produced from present knowledge of the subject. The effects of temperature on insulation life are being investigated continuously, and new data may affect future revisions of this guide. The word conservative as used above is used in the sense that the expected loss of insulation life for a single overload cycle will not be greater than the amount stated.

Because the cumulative effects of temperature and time in causing deterioration of insulation are not thoroughly established, it is not possible to predict with any great degree of accuracy the length of life of a transformer even under constant or closely controlled conditions, much less under widely varying service conditions. Deterioration of insulation is generally characterized by a reduction in mechanical strength and in dielectric strength, but these characteristics may not necessarily be directly related. In some cases, insulation in a charred condition will have sufficient insulating qualities to withstand normal operating electrical and mechanical stresses. A transformer or voltage regulator having insulation in this condition may continue in service for many months or even years, if undisturbed. On the other hand, any unusual movement of the conductors, such as may be caused by expansion of the conductors due to heating resulting from a heavy overload or to large electromagnetic forces resulting from short circuit, may disturb the mechanically weak insulation such that turn-to-turn or layer-to-layer failure will result.

The recommendations of this guide are based upon the life expectancy curve of Figure 1, which relates to the insulation system, but does not account for such factors as deterioration of gaskets, rusting of tanks, etc., that are induced by exposure to the elements of the weather in normal operations.

8.1.2 Normal life expectancy

The basic loading of a distribution transformer or voltage regulator for normal life expectancy is continuous loading at rated output when operated under usual service conditions as indicated in 4.1 of IEEE Std C57.12.00-2010 and 4.1 of IEEE Std C57.15-2009. It is assumed that operation under these conditions is equivalent to operation in a constant 30 °C ambient temperature. The hottest-spot conductor temperature is the principal factor in determining life due to loading. Direct temperature measurement of the hottest-spot may not be practical on commercial designs. The indicated hottest-spot temperatures have therefore been obtained from tests made in the laboratory and mathematical models. The hottest-spot temperature at rated load is the sum of the average winding temperature and a hottest-spot allowance, usually 15 °C. Normal life expectancy will result from operating continuously with hottest-spot conductor temperature of 110 °C or an equivalent daily transient cycle. For mineral oil-immersed transformers and voltage regulators operating continuously under the foregoing conditions this temperature has been limited to a maximum of 110 °C. Normal life expectancy of transformer and voltage regulator insulation using different criteria is given in Table 1. Distribution and power transformer model tests indicate that the normal life expectancy at a continuous hottest-spot temperature of 110 °C is 20.55 years.

8.2 Limitations

8.2.1 General

When loading distribution transformers and voltage regulators above nameplate rating, other limitations may be encountered. Among these limitations are oil expansion, pressure in sealed units, and the thermal capability of bushings; leads, tap changers, or associated equipment such as cables, reactors, circuit breakers, fuses, disconnecting switches, and current transformers. Any of these items may limit the loading to less than the capability of the winding insulation. Manufacturers should, therefore, be consulted before loading transformers or voltage regulators above nameplate rating. Operation at hottest-spot temperatures above 140 °C may cause gassing in the solid insulation and the oil. Gassing may produce a potential risk to the dielectric strength integrity of the transformer or voltage regulator and this risk should be considered when the guide is applied.

Distribution transformers are sometimes installed in subsurface manholes and vaults of minimum size with natural ventilation through roof gratings. This type of installation results in a higher ambient temperature than the outdoor air. The amount of increase depends on the design of the manholes and vaults, net opening area of the roof gratings, and the adjacent subsurface structures. Therefore, the increase in effective ambient temperature for expected transformer losses must be determined before loading limitations can be estimated.

The separate heating effects of loading a distribution transformer or voltage regulator, and of solar radiation, may each result in an enclosure surface temperature high enough to present a hazard to personnel who might come in contact with the enclosure surface where unlimited access to the transformer or voltage regulator exists (such as certain pad-mounted units).

8.2.2 Limitations for loading distribution transformers above nameplate rating

Suggested limits of temperature or load for loading distribution transformers above the nameplate rating are given in Table 5 (note the above discussion on hottest-spot temperatures in excess of 140 °C).

Table 5—Suggested limits of temperature or load for loading above nameplate distribution transformers with 65 °C rise

Top-oil temperature	120 °C
Hottest-spot conductor temperature	200 °C[a]
Short-time loading (1/2 h or less)	300%

[a] See discussion on hottest-spot temperatures in excess of 140 °C in 8.2.1.

8.3 Types of loading

8.3.1 Loading for normal life expectancy under specific conditions

Distribution transformers and voltage regulators may be operated above 110 °C average continuous hottest-spot temperature for short periods provided they are operated for much longer periods at temperatures below 110 °C. This is due to the fact that thermal aging is a cumulative process. This permits loads above the rating to be safely carried under specified conditions without encroaching upon the normal life expectancy of the transformer and voltage regulator. When the ambient temperature is below the 30 °C ambient used to establish the transformer's or voltage regulator's rating, or when the transformer's temperature rises at nameplate rated load, as determined by test, are less than the normal limiting values, some additional load beyond nameplate rating is possible within normal life expectations.

8.3.2 Loading by top-oil temperature

Top-oil temperature alone should not be used as a guide for loading transformers and voltage regulators. The hottest-spot winding rise over top-oil temperature at full load should be determined from the factory tests corrected for the actual load carried by using Equation (18). This hottest-spot rise over top-oil, subtracted from 110 °C, will give the maximum permissible top-oil temperature for normal life expectancy. It should be recognized that, due to the thermal lag in the oil temperature rise, time is required for a transformer or voltage regulator to reach a stable temperature for any change in load. Therefore, higher peak loads may be carried for a short duration. If the transformer or voltage regulator characteristics are not accurately known, maximum top-oil temperatures derived from Figure 5 may be used as an approximate guide. Figure 5 is based on a difference between hottest-spot temperature and top-oil temperature of 25 °C at rated load.

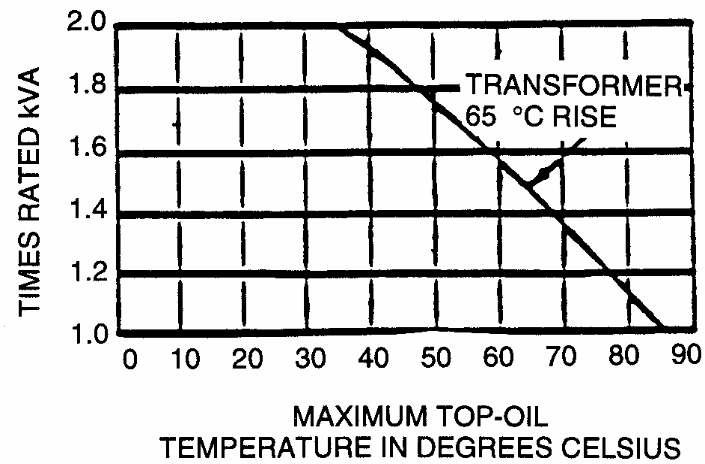
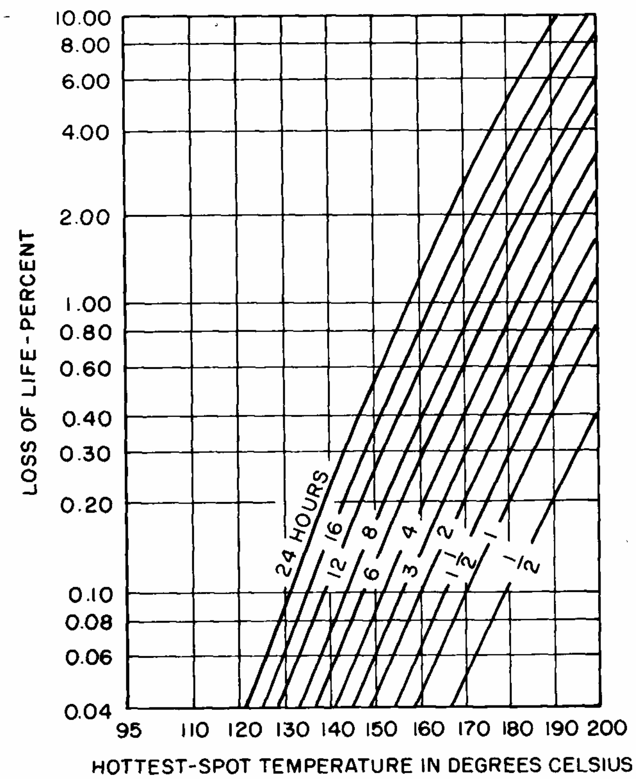


Figure 5— Approximate continuous loading for normal life expectancy based on maximum top-oil temperature



Time (h)	0.05	0.10	0.25	%loss of life[a] 0.50	1.00	2.00	4.00
1/2	171	180	193	204[b]			
1	161	171	183	193	204[b]		
2	153	161	174	183	193	204[b]	
4	144	153	164	174	183	193	204[b]
8	136	144	155	164	174	183	193
16	128	136	147	155	164	174	183
24	124	131	142	150	159	168	178

[a] Calculated for one occurrence on the assumption that the hottest-spot temperature remains constant for the specified time duration. For loss of life determinations in which the time-temperature response of the transformer is taken into account, refer to clauses 5 and 7.
[b] Maximum permissible value is 200 °C; the underlined values permit interpolation.

Figure 6—Loss of life expectancy (based on a normal life of 180 000 h)

8.3.3 Continuous loading based on average winding test temperature rise

For each degree Celsius in excess of 5 °C that the average winding test temperature rise is below 65 °C, the transformer or voltage regulator load may be increased above rated kVA by 1.0%. The 5 °C margin is taken to provide a tolerance in the measurement of temperature rise. The load value thus obtained is the kVA load, which the transformer or voltage regulator can carry at 65 °C rise. Since this may indicate a load capability beyond that contemplated by the designer, the limitations given in 8.2 should be checked before taking full advantage of this increase.

The above is not applicable to all distribution transformers and voltage regulators. Some transformers are designed to have the difference between the hottest-spot and average winding temperatures greater than the 15 °C allowance. This will result in an average winding temperature rise of less than 65 °C, while the hottest-spot winding rise may be at the 80 °C limiting value. This condition may exist in transformers and voltage regulators with large differences between top and bottom-oil temperatures. The manufacturer should be consulted for information on the hottest-spot allowance used for these designs.

8.3.4 Short-time loading with moderate sacrifice of life expectancy (operation above 110 °C hottest- spot temperature)

When for any given period of time the aging effect of one overload cycle or the cumulative aging effect of a number of overload cycles is greater than the aging effect of continuous operation at rated load, the insulation deteriorates at a faster rate than normal. The rate of deterioration is a function of time and temperature and is commonly expressed as a percentage loss of life per incident. A chart and table showing relative loss of life for various combinations of time and temperature are given in Figure 6 for 65 °C rise transformers and voltage regulators.

It should be clearly understood that, while the insulation aging rate information is considered to be conservative and helpful in estimating the relative loss of life due to loads above nameplate rating under various conditions, this information is not intended to furnish the sole basis for calculating the normal life expectancy of transformer and voltage regulator insulation. The uncertainty of service conditions and the wide range in ratings covered should be considered in determining a loading schedule. Some of the variables are wide differences in ambient temperature between localities; differences in elevation; restricted air circulation caused by buildings, fire walls, etc.; previous emergency loading history that may not be known to the operator; and variations in design characteristics. As a guide, many users consider an average loss of life of 4% per day in any one emergency operation to be reasonable.

8.4 Loading specific to voltage regulators

8.4.1 General

Most voltage regulators are 55 °C rise products and of sealed construction, using thermally upgraded paper insulation. Some voltage regulator nameplates show both 55 °C and 65 °C ratings with a 1.12 factor in the kVA rating for the higher rise units. The tap changer is integral to the regulator and usually is the critical factor in establishing the loading limits. Contact life is significantly affected by loading practices.

Regulators are thermally designed and nameplate rated for operation continuously at the extreme raise and lower tap positions. According to IEEE Std C57.15, regulators may be continuously loaded, in discretely defined increments, above that rating if the tap position range is restricted. This factor differs for single-phase and three-phase regulators.

Most regulators are designed for application at multiple nominal system voltages but one specific load rating.

8.4.2 Restricted regulation

Many step-voltage regulators are adjusted to step voltages up or down less than their maximum design amount. When step-voltage regulators have restricted voltage ranges, less series winding is in the circuit and the load current in the shunt winding is less than at the full range of regulation.

The manufacturer should be consulted for his recommendation concerning additional load current that can be carried when the voltage range is restricted. Limitations indicated in 8.2.1 may affect the maximum loads indicated in Table 6, which gives an approximate guide for restricted range application. The loads given in Table 6 will give a normal life expectancy.

Table 6—Loading with reduced regulation (based on ± 10 % range)

Limiting regulating range %	Load (% of rated load)
± 10	100
± 8 ¾	110
± 7 ½	120
± 6 ¾	135
± 5	160

8.4.3 Loading with reduced voltages

Step-voltage regulators are sometimes applied to systems operating at voltages below their nameplate rating. Under these conditions, the percent regulation remains the same.

The load current rating does not change; however, the kVA rating and the kVA being controlled are both reduced in proportion to the voltage being used for most voltage ratings. The only exception is 7620 volt rating. This voltage rated regulator will commonly be applied at the lower voltage of 7200 volts.

8.4.4 Limitations for loading voltage regulators above nameplate rating

Suggested limits of temperature and load for loading above the nameplate rating are given in Table 7.

Table 7—Suggested limits of temperature and load for loading above nameplate voltage regulators with 55 °C or 65 °C Rise

Description	55 °C	65 °C
Top Oil Temperature	100 °C	110 °C
Hottest Spot Conductor Temperature	180 °C	180 °C
Short Time Loading (1/2 hour or less)	200%	200%

9. Loading of power transformers

9.1 Types of loading and their interrelationship

Power transformer life expectancy at various operating temperatures is not accurately known, but the information given regarding loss of insulation life at elevated temperature is the best that can be produced from present knowledge of the subject. Loads in excess of nameplate rating may subject insulation to temperatures higher than the basis of rating definition. To provide guidance on risk associated with higher operating temperature, four different loading conditions beyond nameplate have been developed as examples, and are used throughout this guide. The time and temperature limits shown in Table 9 to explain the basis of these examples, are appropriate for the system development and system operations philosophy of some transformer owner companies. Other companies have developed and use other limits that are consistent with their philosophies. These may be the same limits as shown in Table 8. (For example: loading guides developed by some Independent System Operators (ISOs) have always used the limits in Table 8, and continue to do so.) This guide recommends that each transformer owner develop and use the limits that are consistent with their operational philosophy. An increased risk is probable for each successive loading with its attendant increased temperature. For each higher temperature, a higher risk loading condition can be assumed to be additive to any lower risk condition accepted by the user except for the short-time emergency loading. The four types of loading are as follows:

Normal life expectancy

a) Normal life expectancy loading

Sacrifice of life expectancy

b) Planned loading beyond nameplate
c) Long time emergency loading
d) Short time emergency loading

Examples of loads that fall in these categories are illustrated in Figure 7.

9.2 Limitations

9.2.1 Temperature or load limitations

Suggested limits of temperatures or loads for loading above nameplate rating are given in Table 8. Suggested limits of temperature which give reasonable loss of life for the four types of loading are given in Table 9.

Table 8—Suggested limits of temperature or load for loading above nameplate power transformers with 65 °C rise

Top-oil temperature	110 °C
Hottest-spot conductor temperature	180 °C
Maximum loading	200%

Table 9— Maximum temperature limits used in the examples in this guide

	Normal life expectancy loading	Planned loading beyond namepla te rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature, °C	120 [a]	130	140	180 [b]
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature,°C	105	110	110	110

[a] 110 °C on a continuous 24 h basis (80 °C winding hottest spot rise over a 40 °C maximum ambient).
[b] Gassing may produce a potential risk to the dielectric strength of the transformer. This risk should be considered when this guide is applied refer to Annex A.
[c] The time and temperature limits shown in Table 9 to develop the examples, are appropriate for the system development and system operations philosophy of some companies. Other companies have developed and use other limits that are consistent with their philosophies.

Usually the limits of hot-spot temperature for other metallic parts not in contact with insulation are design limits and calculated by the manufacturer when an overload specification is submitted as part of the purchasing specifications.

9.2.2 Ancillary components

Tap changers bushings, leads, and other ancillary equipment may restrict loading to levels below those calculated by the equations in Clause 7 or Annex G. The user may wish to specify that ancillary equipment not restrict loading to levels below those permitted by the insulated conductor and other metallic part hot spots. Additional information on loading of ancillary components is given in Annex B.

9.2.3 Risk considerations

Normal life expectancy loading is considered to be risk free; however, the remaining three types of loading have associated with them some indeterminate level of risk. Specifically, the level of risk is based on the quantity of free gas, moisture content of oil and insulation, and voltage. The presence of free gas as discussed in Annex A may cause dielectric failure during an overvoltage condition and possibly at rated power frequency voltage. The temperatures shown in Table 9 for each type of loading are believed to result in an acceptable degree of risk for the special circumstances that require loading beyond nameplate rating. A scientific basis for the user's evaluation of the degree of risk is not available at this time. Current research in the area of model testing has not established sufficient quantitative data relationships between conductor temperature, length of time at that temperature, and reduction in winding dielectric strength. Additionally, there are other important factors that may affect any reduction, such as moisture content of the winding insulation and rate of rise of conductor temperature.

9.3 Normal life expectancy loading

9.3.1 General

The basic loading of a power transformer for normal life expectancy is continuous loading at rated output when operated under usual conditions as indicated in 4.1 of IEEE Std C57.12.00-2010. It is assumed that the operation under these conditions is equivalent to operation in an average ambient temperature of 30 °C for cooling air or 25 °C for cooling water. Normal life expectancy will result from operating with a continuous hottest-spot conductor temperature of 110 °C (or equivalent variable temperature with 120 °C maximum in any 24 h period). The 110 °C hottest-spot temperature is based on the hottest-spot rise of 80 °C plus the standard average ambient temperature of 30 °C.

Transformers may be operated above 110 °C hottest-spot temperature for short periods providing they are operated for much longer periods at temperatures below 110 °C. This is due to the fact that thermal aging is a cumulative process and thus permits loads above the rating to be safely carried under many conditions without encroaching upon the normal life expectancy of the transformer. The equations given in Clause 7 or Annex G may be used to calculate the hottest-spot and top-oil temperatures as a function of load for normal life expectancy.

9.3.2 Influence of ambient temperature on normal life expectancy loading

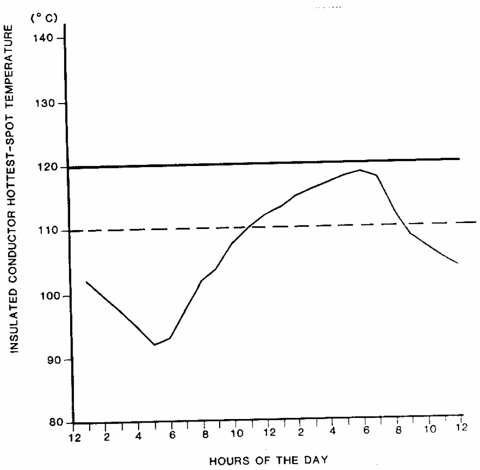
The influence of ambient temperature on normal life expectancy loading is given in Clause 6.

9.3.3 Normal life expectancy loading by top-oil temperature

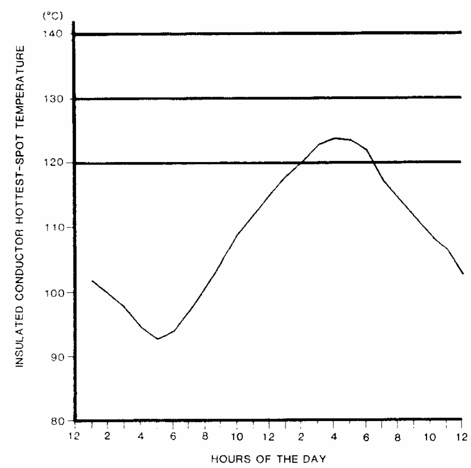
Top-oil temperature alone should not be used as a guide for loading power transformers. The hottest-spot to top-oil gradient at full load should be determined from factory tests or, lacking data a value should be assumed. The full load hottest-spot to top-oil gradient should be corrected to that for actual load using Equation (18). The gradient subtracted from 110 °C will give the maximum permissible oil temperature for normal life expectancy. It should be recognized that, due to thermal lag in oil rise, time is required for a transformer to reach a stable temperature following any change in load.

9.3.4 Normal life expectancy loading by average winding test temperature rise

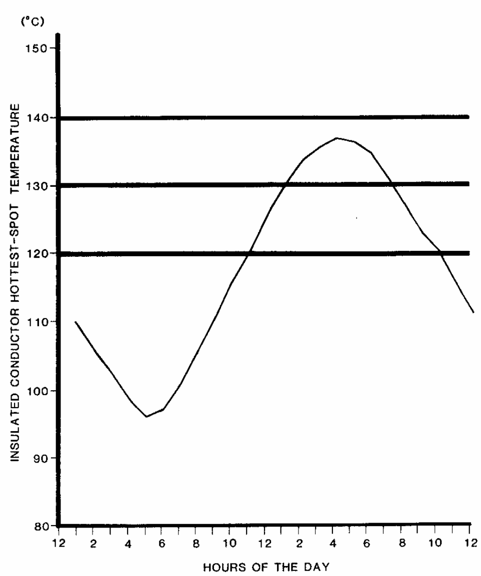
For each 1 °C in excess of 5 °C that the average winding test temperature is below 65 °C, the transformer load may be increased above rated load by the percentages given in Table 3. A 5 °C margin is used to provide a tolerance in the measurement of temperature rise. The load thus obtained is that which the transformer can carry at 65 °C rise. Since this may increase the loading beyond that contemplated by the designer, the limitations given in Table 8 and Table 9 should be checked before taking full advantage of this increased load capability.



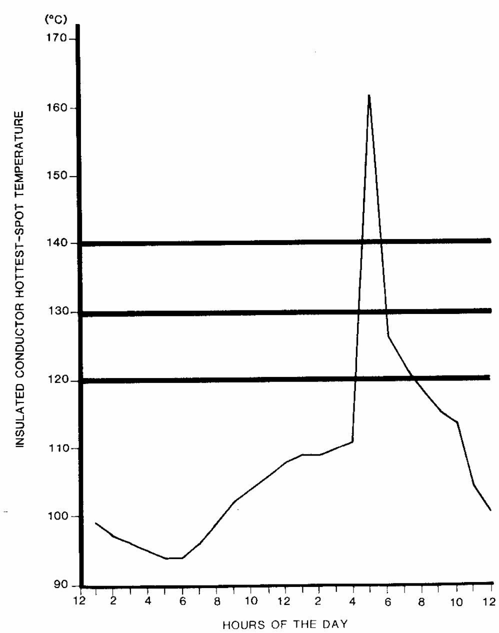
a) Normal life expectancy loading



b) Planned loading beyond nameplate rating



c) Long-time emergency loading



d) Short-term emergency loading

Figure 7— Typical load cycles for the examples

Some power transformers are designed to have the difference between the hottest-spot and average conductor temperature greater than 15 °C. This will result in an average winding temperature rise less than 65 °C, but the hottest-spot winding temperature rise may be the limiting value of 80° C. Such transformers should not be loaded above their rating by using Table I.2. The manufacturer should be consulted for information on the hottest-spot allowances used for these designs. This condition may exist in transformers with large differences (greater than 30 °C) between top and bottom oil temperatures and may be checked approximately by measuring the top and bottom radiator temperatures. Whenever possible, data on hottest-spot and oil temperatures obtained from factory temperature tests should be used in calculating transformer load capability or when calculating temperatures for loads above rating.

9.4 Planned loading beyond nameplate rating

Planned loading beyond nameplate rating results in either the conductor hottest-spot or top-oil temperature exceeding those suggested in Table 9 for normal life expectancy loading, and is accepted by the user as a normal, planned repetitive load. Usually planned loading beyond nameplate rating is restricted to transformers that do not carry a continuous steady load. Suggested conductor hottest-spot temperatures are presented in Table 9. Planned loading beyond nameplate rating example is a scenario wherein a transformer is so loaded that its hottest-spot temperature is in the temperature range of 120 °C–130 °C. The length of time for a transformer to operate in the 120 °C–130 °C range should be determined by loss of insulation life calculations, taking into account the specific load cycle. The characteristics of this type of loading are no system outages, regular and comparatively frequent occurrences, and life expectancy is less than for loading within the nameplate rating.

9.5 Long-time emergency loading

Long-time emergency loading results from the prolonged outage of some system element and causes either the conductor hottest-spot or the top-oil temperature to exceed those suggested for planned loading beyond nameplate rating. This is not a normal operating condition, but may persist for some time. It is expected that such occurrences will be rare. Long-time emergency loading may be applied to transformers carrying continuous steady loads, but loss of insulation life must be determined to be acceptable. Suggested conductor hottest-spot temperatures are presented in Table 9. Top-oil temperature should not exceed 110 °C at any time.

Long-time emergency loading example is a scenario wherein a power transformer is so loaded that its hottest-spot temperature is in the temperature range of 120 °C–140 °C. The characteristics of this type of loading are one long-time outage of a transmission system element, two or three occurrences over the normal life-time of the transformer where each occurrence may last several months, and the risk is greater than planned loading beyond nameplate rating. Figure 7c) illustrates an example of a long-time emergency loading profile. The hottest-spot temperature for this example exceeds 120 °C. Calculations should be made to determine if the loss of insulation life is acceptable for the specific load cycle.

9.6 Short-time emergency loading

Short-time emergency loading is an unusually heavy loading brought about by the occurrence of one or more unlikely events that seriously disturb normal system loading and cause either the conductor hottest-spot or top-oil temperature to exceed the temperature limits suggested for planned loading beyond name-plate rating. Acceptance of these conditions for a short time may be preferable to other alternatives. Suggested conductor hottest-spot temperatures are presented in Table 9. Top-oil temperature should not exceed 110 °C at any time. This type of loading, with its greater risk, is expected to occur rarely.

Short-time emergency loading example is a scenario wherein a transformer is so loaded that its hottest-spot temperature is as high as 180 °C for a short time. The characteristics of this type of loading are a series of unlikely conditions on the transmission system (second or third contingency), one or two occurrences over the normal lifetime of the transformer, and the risk is greater than for long-time emergency loading. Calculations should be made to determine if the loss of insulation life during the short-time emergency is acceptable for the specific load cycle. Figure 7d) illustrates an example of a short-time emergency loading profile. This figure presents a temperature curve that had leveled off for the day until about 4 p.m. when a system condition occurs that loads the transformer so that its hottest-spot temperature rises rapidly to 163 °C in 1 h.

9.7 Loading information for specifications

If the maximum load capacity that a transformer user plans to utilize on a planned or emergency basis is included in the specifications at the time of purchase, the following information should be given:

a) Load
   1) Two step load cycle approach Prior steady-state load, percent of maximum nameplate rating
      — Maximum load, percent of maximum nameplate rating
      — Duration
   2) Load cycle over a 24 h period
b) Ambient temperature, °C
   1) Constant for load cycle approach [see item a)1)]
   2) Variable over the load cycle for load cycle approach [see item a)2)]
c) Type of loading, planned or emergency, long-time or short-time
d) Limiting top-oil temperature
e) Limiting hottest-spot temperature
f) Statement that ancillary components not limit the loading capability

More than one set of loading conditions may be used. The load cycle with limiting top-oil and hottest-spot temperatures determine loss of life, which may be calculated.

9.8 Operation with part or all of the cooling out of service

When auxiliary equipment, such as pumps or fans, or both, is used to increase the cooling efficiency, the transformer may be required to operate for some time without this equipment functioning. The permissible loading under such conditions is given in Annex H.

Annex A

(normative)

Thermal evolution of gas from transformer insulation

A.1 General

A new bubble generation model was developed by Oommen outlined in EPRI reports EL 6761 [A7][7] and EL 7291 [A8] in March 1990 and March 1992 respectively. This is the basis of Equation (7) in Clause 7. The new model used realistic coil segments to produce bubbles under overload conditions.

An earlier model (see Fessler [A9] and McNutt, Rouse, and Kaufman [A22]) given in Annex A of the 1995 version of IEEE Std C57.91 was developed purely from physical and chemical considerations regarding bubble generation based on vapor pressure computations and the gas content of oil. It had been assumed in that model that the condition for generation of a bubble was that the total gas/vapor pressure contribution exceeds the external pressure exerted on the bubble. The total gas/vapor pressure contribution was computed from the gas content of the bubble (from mostly dissolved nitrogen and some generated gases) and from water vapor released by heat from paper insulation in contact with the hot conductor. The bubbles in an initially degassed system (as in sealed transformers with conservators) would mostly consist of water vapor. It was argued that in a nitrogen saturated system, the bubbles would contain mostly nitrogen, and the balance would be from water vapor and generated gases. These assumptions led to the conclusion that in a gas saturated system bubbles would be formed much earlier than in a conservator system because only a small increase in temperature would be needed to release sufficient water vapor. It was estimated that the bubble evolution temperature in a gas saturated system would be as much as 50 °C lower than the bubble evolution temperature in a conservator system.

A complete re-evaluation of the basic assumptions and experimental methods to verify bubble evolution was conducted in the new study. The significant findings are given below.

The fundamental equation governing bubble formation is

$$P_{int.} = P_{ext.} + (2\sigma / R_B) \tag{A.1}$$

where

P_{int} = internal pressure
P_{ext} = external pressure
R_B = Radius of bubble
σ = Surface tension

The second term on the right is the surface tension pressure. In the previous model, the second term had *been* completely ignored. However, this term has great significance for a micro bubble. As R_B becomes smaller and smaller, the second term would carry more and more weight, and may exceed the first term. This would imply that the surface tension pressure would force the collapse of a micro bubble. So the assumption that a visible bubble is formed by the growth of a micro bubble is not theoretically sound.

How then is a bubble formed? Experts agree that a bubble is formed by the expansion of a surface cavity that has initial gas/vapor content. To apply to a paper wrapped conductor, we can assume the existence of tiny cavities on the paper surface initially filled with small amounts of water vapor and dissolved gases (mostly nitrogen). Under overload conditions the conductor and paper would overheat and the cavity would

[7] The numbers in brackets combined with the letter "A" correspond to those of the bibliography in Annex A.

expand at first into which water vapor would be injected. As the cavity grows, the bubble would have higher and higher quantities of water vapor. The nitrogen content would hardly change in such limited time. It becomes obvious that we should expect bubble formation to be dictated by water vapor release and not by the nitrogen content of the oil. The contribution from generated gases becomes even less important.

A.2 Experimental verification

Two coil models were used for experimental studies. One model had a fiber optic temperature sensor in place of thermocouple sensor to sense hot spot temperature and a separate winding was used to apply voltage for PD detection of bubbles in addition to visual observation. Moisture content of the paper in the coil and gas content of the oil were changed over a wide range. Moisture ranged from 0.5% to 8.0% (dry/oil free basis), and gas content, from fully degassed to (nitrogen) saturated. A rapid temperature rise simulated the conditions in a transformer winding under overload conditions.

It was observed that at low moisture values the bubble evolution temperature is virtually the same for degassed and gas saturated systems. The previous model had predicted a 50 °C difference. Only at high moisture levels there would be a significant influence from the gas content. It will also be noticed that at 2% moisture in paper (corresponding to an aged transformer) the bubble evolution temperature is slightly above 140 °C. At 0.5% moisture level the bubble evolution temperature is above 200 °C. In other words, even at the proposed 180 °C hot spot condition bubbles will not be produced from very dry insulation. However, most transformers have insulation moisture levels in the range of 1–1.5%; hence it is prudent not to exceed 150 °C hot spot temperature. Premature aging of paper and the resulting loss of life is always a concern, and the Loading Guide enables its users to estimate the loss of life from short-term overloads.

In addition to fully de-gas and fully gas saturated systems, several tests were conducted with partly degassed oil. In total, 22 coil model tests were conducted. It was possible to fit the hot spot temperature as a function of moisture and gas content and the total external pressure (atmospheric plus oil head). The equation is given below:

$$\Theta_{bubble} = \left[\frac{6996.7}{22.454 + 1.4495 \ln W_{WP} - \ln P_{pres}} \right] - \left[\left(e^{(0.473 W_{WP})} \right) \left(\frac{V_g^{1.585}}{30} \right) \right] - 273 \qquad \text{(A.2)}$$

where

P_{pres} = Total pressure, mm mercury (torr.)
V_g = Gas content of oil, % (v/v)
W_{WP} = Per cent by weight of moisture in paper (dry basis)
Θ_{bubble} = Temperature for bubble evolution, °C

The first part of the equation between the braces is for degassed oil and was derived from the well known Piper chart of vapor pressure vs. moisture relationship. The second term adjusts for the gas content of the oil. The agreement between observed and computed temperatures was excellent, with not more than two degrees difference for tests with the single coil model, and not more than four degrees with the triple disc coil model (for which visual bubble observation was harder, and no PD detection was used).

There is no need to consider the contribution of generated gases as in the previous model because their level is far below that of the dissolved nitrogen.

Dry basis for the percent by weight of moisture in paper means that the moisture is based on the dry, oil-free weight of paper. The percentage water estimated on a ‘wet, oily’ basis (as is usually done) will be lower than on the dry, oil-free basis because the weight of the paper would include both oil and water.

A.3 Determination of equation parameters

There are two indirect methods for the assessment of moisture in paper insulation in transformers as follows:

1) Recovery Voltage Measurement (see Bognar et al. [A2]). This requires the application of a DC voltage while the transformer is de energized. Moisture estimates are made by comparison to systems with known moisture content.
2) Moisture Equilibrium Curves (see Degnan et al. [A5] and Du et al. [A27]). Under steady state conditions achieved at constant load, the moisture in paper and oil achieve equilibrium conditions. A set of equilibrium curves may be used for the estimation of moisture content of paper based on the moisture content of oil, which is easily determined.

Confirmation of moisture in paper can be obtained by measuring moisture in oil at two constant oil temperatures. It can be seen that the accuracy of estimation increases as higher and higher temperatures are chosen due to the slope of the curves, and also because equilibrium is achieved sooner. In practice, the oil temperature could be in the 50–80 °C range. Since the moisture in oil is measured in the lab from an oil sample taken, it is necessary to note the oil temperature. It is also necessary to keep the oil warm so that free water is not formed on cooling down (at room temperature moisture saturation is about 60 mg/kg (ppm), and hence a sample with 95 mg/kg (ppm) would produce some free water. By taking an oil sample at lower temperature the risk of saturation is avoided, but the accuracy of estimation would suffer. It is advised that some practice runs are made by the utility person. The effort is well worth it because once the moisture in the paper is determined, it is going to remain stable for a considerably long time. After a few years, the measurement may be repeated because aging of paper would slightly increase moisture content of paper. Any leaks or exposure of the insulation to the atmosphere would also affect the moisture content of the paper. After maintenance operations or field dry out, a repeat moisture determination should be made.

The oil head may be estimated from the outline drawing and the liquid level dimension given on the nameplate. Since the bubble evolution temperature during overload is of primary interest, the pressure may be assumed to be the maximum operating pressure given on the nameplate.

A.4 Example

Gas content may be estimated based on the type of liquid preservation system; however gas content only slightly affects the bubble evolution temperature calculated using Equation (A.2).

The following example illustrates the use of Equation (A.2):

Assume 1.2% water in the paper insulation. To compute the bubble evolution temperature from a winding at a depth of 2.4384 m from the top oil level of a large power transformer, the oil head must be added to the pressure in the gas space above the oil. Assume 1% gas content in the oil. Then,

Water in paper, W_{WP}	=	1.2	%
External pressure,	=	750	torr
Oil head (2.4384 m)	=	176	torr
Total pressure, P_{pres}	=	926	torr
Gas content, V_g	=	1.0	%

Using Equation (A.2), you get Θ_{bubble} = 167 °C. With a gas content of 8%, the bubble evolution temperature would drop by only a degree. However, if the moisture content is also 8%, the bubble evolution temperature would be 63 °C. If the water content in the paper is 2%, the bubble evolution temperature would be in the 140–150 °C range. Some published papers on bubble evolution have stated that 140 °C is the bubble evolution temperature, but the moisture content was not specified or accurately determined (Heinrichs [A16]). The new equation is applicable to aged and somewhat wet insulation.

Moisture content appears to be the most critical parameter in determining bubble evolution temperature. However, direct moisture determination would require a paper sample, especially from the hot spot region. This is not practical; hence indirect methods have to be used. The moisture parameter used in Equation (A.2) is the average moisture content.

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Annex B

(normative)

Effect of loading transformers above nameplate rating on bushings, tap changers, and auxiliary components

B.1 Bushings

B.1.1 General

The following discussion applies to oil-impregnated, paper-insulated, capacitance-graded bushings only. For other bushing types, consult with the manufacturer for loading guidelines. Bushings are normally designed with a hottest- spot total temperature limit of 105 °C at rated bushing current with a transformer top-oil temperature of 95 °C averaged over a 24 h time period. Operating a transformer beyond nameplate current can result in bushing temperatures above this limit, which cause bushing loss-of-life depending on the actual time-temperature profile the bushing sees.

A number of factors that reduce the severity of bushing overloads compared to transformer winding insulation overloads include the following:

a) Transformer top-oil temperature may be well below 95 °C at rated transformer output.
b) Bushings are sealed units preserving insulation and thermal integrity.
c) Bushing insulation is usually drier than transformer insulation.
d) Bushing insulation is not significantly stressed by fault-current forces.
e) The use of bushings with higher current ratings than the connected transformer windings.

Possible bushing overload effects include the following:

— Internal pressure build-ups
— Aging of gasket materials
— Unusual increases in power factor from thermal deterioration
— Gassing caused by hottest-spots in excess of 140 °C
— Thermal runaway from increased dielectric losses at high temperatures
— Heating in metallic flanges due to stray magnetic flux

The following overload limits are established for coordination of bushings with transformers:

Ambient air	40 °C maximum
Transformer top-oil temperature	110 °C maximum
Maximum current	2 times rated bushing current
Bushing insulation hottest-spot temperature	150 °C maximum

Methods for calculating bushing lead steady-state and transient hottest-spot temperatures are included in IEEE Std C57.19.100™ [B3].[8]

The insulation used in condenser bushings is not thermally upgraded. The relation of insulation deterioration to changes in time and temperature is assumed to follow an adaptation of the Arrhenius reaction rate theory, which states that the logarithm of insulation life is a function of the reciprocal of absolute temperature.

$$Log_{10}(LIFE) = \left[\frac{6972.15}{\Theta_{HS} + 273} - 14.133 \right] \tag{B.1}$$

where

LIFE	is the life of bushing insulation, h
Θ_{HS}	is the bushing insulation hottest-spot temperature, °C

Equation (B.1) indicates that bushings operated at rated current and rated insulation hot-spot temperature have a predicted life less than that of the transformer insulation. In most cases, bushings are applied at less than rated top-oil temperature and in many cases the transformer rated current is less than the bushing rated current. This results in bushing life equivalent to the transformer insulation life. Considerations may also be given to using a per-unit life concept and the insulation aging Equation (3) for 55 °C rise transformers.

B.1.2 Draw leads in bushings

Some bushings are designed for a solid or hollow copper rod inside the bushing to give the full bushing rating. Some bushings are also designed to substitute a draw lead cable for the conductor inside the bushings. When a bushing is operated in the draw lead mode, the thermal performance is determined by the size of the lead supplied as part of the transformer, and the nameplate rating of the bushing may not apply. The draw leads may limit transformer loading to less than the capability of the transformer winding insulation or the capability of the bushing.

B.2 Tap-changers

B.2.1 Tap-changers for de-energized operation (TCDO)

ANSI standards do not specify the temperature rise of the contacts for TCDOs. However, TCDO and LTC tap-changers have similar requirements concerning temperature rise of contacts. The rise will also depend on the design of contacts and the “condition” of the contacts when the loading occurs. Although tap-changer contacts may have certain overload capabilities when new, these capabilities may decrease due to a thin film build-up on the contacts that occurs during normal service. Once a contact reaches a critical temperature, a thermal runaway condition can occur. The contacts overheat and a deposit builds up around the contacts, increasing contact resistance until it finally reaches a temperature that will generate gas. As a minimum, this will produce a gas alarm. As a maximum, the gas may trigger a dielectric failure of the transformer.

The thin film build-up described above can be effectively controlled if the TCDO is operated a minimum of once a year. This can be done during an outage for maintenance or whenever the transformer is de-energized to change taps. Whenever this opportunity occurs, the TCDO should be operated across its full range approximately 10 times to ensure that all the contacts have been wiped clean. With clean contacts, the problem of thermal runaway and deposit buildup during overload conditions can be minimized. After operation of the TCDO it would be good industry practice to perform electrical tests of the transformer to confirm correct operation and final position of the TCDO prior to re-energization.

[8] The numbers in brackets combined with the letter “B” correspond to those of the bibliography in Annex B.

If, in the transformer owner's experience, the de-energized tap-changer has been operated periodically without problems, the previous paragraph is recommended to ensure that the contacts will remain in the best possible condition. However, if, in the owner's experience, the de-energized tap changer has not proven to be completely reliable (as a result of misalignment of the contacts or failure of the mechanized mechanism), the owner may not wish to operate it under any circumstances.

The decision to follow the recommendation of the above paragraph should be tempered by the actual experience with each transformer.

B.2.2 Load tap-changers

IEEE Std C57.131™ [B4] and IEC 60214 [B1] provide the basis for the rating of a load tap-changer. Most North American transformer manufacturers have complied with the requirements of IEC 60214 [B1] prior to the approval of IEEE Std C57.131 [B4]. The manufacturer should be consulted if it is necessary to assure that a specific LTC has been designed to these standards.

According to both standards, the basis for the current rating of an LTC includes the following:

a) Temperature rise limit of 20 °C for any current carrying contact in oil when operating at 1.2 times the maximum rated current of the LTC.

b) Capable of 40 breaking operations at twice maximum rated current and kVA. Oscillograms taken for each operation shall indicate that in no case is the arcing time such as to endanger the operation of the apparatus.

Standards allow tap-changer contacts to work in 100 °C oil with a temperature rise of 20 °C at 1.2 times the nameplate rating. Also, experience has shown that carbon starts to develop on contacts in oil at elevated temperatures (in the order of 120 °C). How serious this growth of carbon becomes depends on the wiping action of the switch contacts, the frequency that switch operation takes place, and how long the high temperature persists. Another important factor is whether the LTC is located in the main tank or in a separate compartment. Usually arcing contacts of the LTC are located in a separate compartment and the oil temperature is less than 100 °C.

Contact temperature rise over oil can be estimated using the following equation:

$$\Delta\Theta_c = \Delta\Theta_{c,R} \times K^n \tag{B.2}$$

where

$\Delta\Theta_c$ is the contact temperature rise over oil at per-unit load K, °C
$\Delta\Theta_{c,R}$ is the contact temperature rise over oil at rated current, °C
K is the load through the LTC in per unit of LTC current rating
n is the exponent of contact temperature rise and may vary over a range of 1.6–1.85. If an exact exponent, based on test results, is not known, a value of 1.8 may be used.

Total contact temperature can then be determined as follows:

$$\Theta_c = \Theta_A + \Delta\,\Theta_{TO,LTC} + \Delta\,\Theta_c \tag{B.3}$$

where

Θ_c	is the total contact temperature, °C
ΘA	is the ambient temperature, °C
$\Delta\Theta_{TO,\,LTC}$	is the oil temperature rise over ambient in LTC compartment at per-unit load K, °C
$\Delta\Theta_c$	is the contact temperature rise over oil, °C

The top-oil temperature in the LTC compartment may not be readily available unless the LTC is located in the main tank of the transformer. If the LTC is located in a separate tank, the LTC oil may be in the order of 5–15 °C cooler than the top-oil temperature in the main tank at rated load. As a rule of thumb, it can usually be assumed that the temperature rise of the oil in a separate tank is 80% of the oil temperature rise in the main tank.

The following is an example using the previous equations for the case where the LTC is located in a separate compartment. This calculation shows that the LTC could carry an emergency load of as high as 1.32 pu at an ambient of 30 °C before a contact temperature of 120 °C is reached. This assumes that, per the standards, the temperature rise of the contacts is 20 °C at 1.2 times the maximum rated load and that the oil temperature rise in the separate compartment is 66 °C at 1.32 pu load.

$$\Delta\,\Theta_{c,R} = \frac{\Delta\,\Theta_c}{K^n} = \frac{20}{(1.2\,)^{1.8}} = 14.4\ ^\circ C$$

where

K	is the ratio of load L to rated load, per unit
n	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
$\Delta\Theta_c$	is the contact temperature rise over oil, °C
$\Delta\Theta_{c,R}$	is the contact temperature rise over oil at rated load, °C

Θ_A	is ambient, °C	= 30 °C
$\Delta\Theta_{TO,\,LTC}$	is the oil rise in LTC compartment (80% of top-oil rise of 82 °C at 1.32 pu load), °C	= 66 °C
$\Delta\Theta_c$	is the maximum contact temperature rise = $14.4 \times (1.32)^{1.8}$, °C	= 24 °C
	Total	120 °C

Some LTC manufacturers have advised caution about using the above approach. One caution is that the cooling ability of the contact geometry and contact mass are also important to consider. In addition, it is not physically possible to actually measure the temperature at the contact point. What is actually measured is a point close to the contact point. The temperature of the actual contact point will be considerably higher. A well-designed transformer will have an LTC capable of carrying the same load as the core and coils. That is, the hottest-spot temperature in the transformer will be the limitation to loading, not the LTC contact temperature. If this is the case, calculations as shown above would not be necessary. However, such calculations may be useful if the LTC limits the output of the transformer.

LTCs designed in accordance with IEEE Std C57.131 [B4] and IEC standards must be capable of 40 breaking operations at twice maximum rated current and kVA. The user would be wise, however, to exercise caution before operating an LTC in this fashion. It should be realized that a factory test is made under ideal conditions (new oil, new contacts, recently adjusted, etc.). Most LTC manufacturers would agree to a few operations per year at twice rated current and kVA. As the number of operations at twice rated current increases, not only would there be additional contact deterioration, but the likelihood of failure of the LTC would also increase. The wear of contacts and contamination of oil increases rapidly with current. Higher overloads on an LTC will necessitate more frequent maintenance.

B.3 Bushing-type current transformers

B.3.1 General

In their normal location, bushing-type current transformers have the transformer top-oil as their ambient, which is limited to 105 °C total temperature at rated output for 65 °C rise transformers. Loading the power transformer beyond nameplate results in an increase in top-oil temperature and secondary current in the current transformer with an associated temperature rise.

A factor in reducing the severity of the current transformer overload is that the top-oil temperature at rated transformer output may be well below 105 °C. In cases where consideration of the loading and top-oil temperature rise of the power transformer and the current in the current transformer indicates the possibility of excessive operating temperatures in the current transformer, the manufacturer should be consulted on the current transformer capability before loading beyond its nameplate rating. The capability of bushing current transformers under operating conditions cannot necessarily be derived from the rating factor.

It may also be possible to select higher current transformer ratios to reduce secondary currents and thus increase the capability of the current transformer.

B.4 Insulated lead conductors

Within the transformer, connections to tap-changer and line terminals and other internal connections are made with insulated leads and cables. The method of calculating the hottest-spot temperature for these leads is different from that employed for the windings. However, the same hottest-spot limits apply equally for both windings and leads since similar insulating materials are normally used. Generally, the loading of the transformer will not be limited by the lead temperature rise. Recommendations of the manufacturer should be sought if proposed loading cycles are in excess of original specifications for the transformer.

B.5 Bibliography for Annex B

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[B2] IEEE Std C57.13™, IEEE Standard Requirements for Instrument Transformers.

[B3] IEEE Std C57. 19.100, IEEE Guide for Application of Power Apparatus Bushings.

[B4] IEEE Std C57. 131, IEEE Standard Requirements for Load Tap Changers.

Annex C

(informative)

Calculation methods for determining ratings and selecting transformer size

C.1 General

A transformer application problem usually needs to answer the question, "Is an available transformer suitable for a given load cycle?" Calculations required to answer this question can be made by hand, or a computer program can be written to automate the calculation. This annex will illustrate calculation procedures used for the determination of loading limits and the selection of a transformer rating. It should be noted that the purpose of the illustration is to show one way to approach the problem. As in most engineering problems, different approaches are possible and judgment must be used in interpreting the results. The principles outlined in the following examples can be applied to all sizes and ratings of transformers. The calculation methods of Annex I may be used to determine if the loss of insulation life for these examples is acceptable.

C.2 Calculation determining loading beyond nameplate rating of an existing transformer

For this example, a 65 °C rise triple rated, ONAN/ODAF/ODAF directed forced-oil cooled transformer rated 112 000/149 333/186 666 kVA will be used. A load profile is given (see Table C.1, normal load in per unit) for a day starting at 6:00 a.m. The hottest-spot winding temperature profile will be determined by calculation. Some simplifying assumptions will be made to make the calculation easier. The first assumption is that maximum cooling will be used throughout the day, even though at the lowest part of the load cycle, the loading will be less than the intermediate rating. The assumption may be optimistic; on the other hand, when loading beyond nameplate rating is planned, it is reasonable to assume that every measure is taken to assist the transformer, including the use of maximum cooling throughout the day.

For the directed forced oil cooling, the n exponent is 1 and no correction of the time constant is required. That is,

$$\tau_{TO} = \tau_{TO,R}$$

where

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

For cooling modes with $n < 1$ the time constant should be corrected and this refinement is easily accomplished with a computer program.

The third assumption is that the load is kept constant during the following hour. For the rising part of the load curve this assumption will give loads that are too low, but on the falling part of the load curve loading values that will be too high. It is possible to refine the load representation when there is need.

The last assumption is that the ambient temperature is constant during the day.

Table C.1— Load cycles and temperature rises for 187 MVA transformer

	Normal load					PLBN				LTE				STE			
Hour	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H	Load pu	$\Delta\Theta_{TO}$	$\Delta\Theta_H$	Θ_H
6	0.52	18.14	19.20	7.73	56.9	0.66	26.86	12.46	69.3	0.66	26.86	12.46	69.3	0.66	26.86	12.46	69.3
7	0.55	17.14	17.94	8.65	56.6	0.69	24.91	13.62	68.5	0.69	24.91	13.62	68.5	0.69	24.91	13.62	68.5
8	0.61	16.63	17.23	10.63	57.9	0.77	23.75	16.96	70.7	0.77	23.75	16.96	70.7	0.77	23.75	16.96	70.7
9	0.70	16.76	17.21	14.01	61.2	0.88	23.74	22.15	75.9	0.88	23.74	22.15	75.9	0.88	23.74	22.15	75.9
10	0.79	17.74	18.07	17.85	65.9	1.00	25.08	28.60	83.7	1.00	25.08	28.60	83.7	1.00	25.08	28.60	83.7
11	0.85	19.47	19.71	20.66	70.4	1.07	27.76	32.74	90.5	1.07	17.76	32.74	90.5	1.07	27.76	32.74	90.5
12	0.90	21.49	21.67	23.17	74.8	1.13	30.85	36.52	97.4	1.13	30.85	36.52	97.4	1.13	30.85	36.52	97.4
13	0.93	23.66	23.79	24.74	78.5	1.17	34.14	39.15	103.3	1.29	34.14	39.15	103.3	1.92	34.14	39.15	103.3
												47.59	111.7		a	a	a
14	0.96	25.69	25.79	26.36	82.2	1.21	37.29	41.87	109.2	1.33	39.48	50.59	120.1	1.33	46.76	50.59	127.4
15	0.98	27.64	27.71	27.47	85.2	1.23	40.36	43.27	113.6	1.36	44.27	52.90	127.2	1.36	49.73	52.90	132.6
16	0.99	29.39	29.44	28.03	87.5	1.25	43.03	44.69	117.7	1.38	48.46	54.47	132.9	1.38	52.55	54.47	137.0
17	1.00	30.84	30.88	28.60	89.5	1.26	45.40	45.41	120.8	1.39	52.01	55.26	137.3	1.39	55.07	55.26	140.3
18	1.00	32.08	32.11	28.60	90.7	1.26	47.36	45.41	122.8	1.39	54.87	55.26	140.1	1.39	57.17	55.26	142.4
19	0.98	33.01	33.03	27.47	90.5	1.23	48.83	43.27	122.1	1.23	57.02	55.26	142.3	1.23	58.74	55.26	144.0
												43.27	130.3			43.27	132.0
20	0.97	33.41	33.43	26.91	90.3	1.22	49.38	42.57	122.0	1.22	55.52	42.57	128.1	1.22	56.81	42.57	129.4
21	0.94	33.57	33.58	25.27	88.9	1.18	49.61	39.82	119.4	1.18	54.21	39.82	134.0	1.18	55.18	39.82	125.0
22	0.90	33.26	33.27	23.17	86.4	1.13	49.07	36.52	115.6	1.13	52.52	36.52	119.0	1.13	53.25	36.52	119.8
23	0.86	32.49	32.49	21.15	83.6	1.08	47.81	33.36	111.2	1.08	50.39	33.36	113.8	1.08	50.94	33.36	114.3
24	0.81	31.39	31.39	18.76	80.2	1.02	46.04	29.76	105.8	1.02	47.98	29.76	107.7	1.02	48.39	29.76	108.2
1	0.68	29.94	29.94	13.22	73.2	0.86	43.78	21.15	94.9	0.86	45.23	21.15	96.4	0.86	45.54	21.15	96.7
2	0.61	27.42	27.42	10.64	68.1	0.77	39.85	16.96	86.8	0.77	40.94	16.96	87.9	0.77	41.17	16.96	88.1
3	0.58	24.86	24.86	9.62	64.5	0.73	35.82	15.24	81.1	0.73	36.63	15.24	81.9	0.73	36.81	15.24	82.1
4	0.55	22.67	22.67	8.65	61.3	0.69	32.35	13.62	76.0	0.69	32.96	13.62	76.6	0.69	33.09	13.62	76.7
5	0.53	20.78	20.78	8.03	58.8	0.67	29.33	12.84	72.2	0.67	29.78	12.84	72.6	0.67	29.88	12.84	72.7
6	0.52	19.20	19.20	7.73	56.9	0.66	26.86	12.46	69.3	0.66	27.20	12.46	69.7	0.66	27.27	12.46	69.7

[a] See C.5 for temperature rises at 13:30 h.

The transformer characteristics at 187 MVA are as follows:

Top-oil rise over ambient at rated load	$\Delta\Theta_{TO,R}$ = 36.0 °C
Hottest-spot conductor rise over top-oil temperature, at rated load	$\Delta\Theta_{HS,R}$ = 28.6 °C
Ratio of load loss at rated load to no-load loss	R = 4.87
Oil thermal time constant for rated load	$\tau_{TO,R}$ = 3.5 h
Exponent of loss function vs. top-oil rise	n = 1.0
Exponent of load squared vs. winding gradient	m = 1

The ultimate top-oil rise over ambient for load K will be, according to Equation (11).

$$\Delta\Theta_{TO,U} = \Delta\Theta_{TO,R}\left[\frac{K_U^2 R + 1}{(R+1)}\right]^n \tag{C.1}$$

$$\Delta\Theta_{TO,U} = 36\left[\frac{K_U^2 (4.87) + 1}{(4.87+1)}\right]^n$$

$$\Delta\Theta_{TO,U} = 29.87 K_U^2 + 6.13$$

where

K_U is the ratio of the ultimate load L to rated load, per unit
R is the ratio of load loss at rated load to no-load loss on the tap position to be studied
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

After 1 h the top-oil temperature rise will be [see Equation (9)].

$$\Delta\Theta_{TO} = (\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i})\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i}$$

where

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C
τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h
t is the duration of load, h

or rewritten:

$$\Delta\Theta_{TO} = \Delta\Theta_{TO,U}\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i}\, e^{-\frac{t}{\tau_{TO}}}$$

where

t is the duration of load, h
$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C
τ is the oil time constant of transformer, h
τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

When we substitute $\tau_{TO} = \tau_{TOR} = 3.5$, and the $\Delta\Theta_{TO,U}$ value of Equation (C.1), we obtain for $t = 1$ h.

$$\Delta\Theta_{TO} = (29.87K^2 + 6.13)\left(1 - e^{\frac{-1}{3.5}}\right) + \Delta\Theta_{TO,i}\, e^{\frac{-1}{3.5}}$$

where

K	is the ratio of load L to rated load, per unit
$\Delta\Theta_{TO}$	is the top-oil rise over ambient temperature, °C
$\Delta\Theta_{TO,i}$	is the initial top-oil rise over ambient temperature for $t = 0$, °C

or

$$\Delta\Theta_{TO} = 7.42K^2 + 1.53 + 0.75\Delta\Theta_{TO,i} \tag{C.2}$$

and for $t = 0.5$ h

$$\Delta\Theta_{TO} = 3.98K^2 + 0.82 + 0.87\Delta\Theta_{TO,i} \tag{C.3}$$

The winding hot-spot rise over top oil will be according to Equation (18).

$$\Delta\Theta_{TO} = \Delta\Theta_{H,R} K^{2m} = 28.6K^2 \tag{C.4}$$

where

K	is the ratio of load L to rated load, per unit
m	is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.
$\Delta\Theta_{H,R}$	is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C
$\Delta\Theta_{TO}$	is the top-oil rise over ambient temperature, °C

One quantity, the initial top-oil rise, is still missing and we will have to estimate it. If we assume the load cycle for normal load found in Table C.1, we may establish the rms value of the load curve, as an example, for the 6 h load preceding 6:00 a.m.

$$K = \sqrt{\frac{\left[(0.81)^2 + (0.68)^2 + (0.61)^2 + (0.58)^2 + (0.55)^2 + (0.53)^2\right]}{6}} = 0.634$$

Using Equation (C.1), a load of this magnitude yields an ultimate top-oil rise of

$$\Delta\Theta_{TO,U} = 29.87K^2 + 6.13 = 29.87(0.634)^2 + 6.13 = 18.14^\circ C$$

Using $\Delta\Theta_{TO,i}$ = 18.14 °C at 6:00 a.m., and K = 0.52, we can determine $\Delta\Theta_{TO}$ at 7:00 a.m. as follows:

$$\Delta\Theta_{TO,U} = 7.42K^2 + 1.53 + 0.75\Delta\Theta_{TO,i} = 17.14^\circ C$$

where

K is the ratio of load L to rated load, per unit
$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C
$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for t = 0, °C

To determine the top-oil temperature rise at 8:00 a.m., set $\Delta\Theta_{TO,i} = \Delta\Theta_{TO}$ calculated at 7:00 a.m. Repeated application of Equation (C.2) will produce a top-oil temperature rise profile; however, a slight discrepancy occurs 24 h later at 6:00 a.m. When one continues to apply Equation (C.2), convergency to true values is soon obtained, as shown in normal load, $\Delta\Theta_{TO}$ columns of Table C.1. The first column represents the first iteration, and the second column represents the results after an additional iteration.

The winding hot-spot rise over top oil, $\Delta\Theta_{TO}$ is considered to be instantaneous. Only where current discontinuities occur will some consideration be given to the winding time-constant.

For example, at 6:00 a.m.:

$$\Delta\Theta_H = (28.6)(0.52)^2 = 7.73^\circ C$$

The equation, $\Theta_H = \Delta\Theta_{TO} + \Delta\Theta_H + \Theta_A$, will be used to establish the hottest-spot winding temperature Θ_H, using for ambient temperature Θ_A = 30.0 °C.

A complete daily normal load cycle is shown in Table C.1 and plotted in Figure C.1.

C.3 Planned loading beyond nameplate (PLBN)

The constant on PLBN loading is hottest-spot winding temperatures in the 120–130 °C range; therefore, $\Delta\Theta_{TO} + \Delta\Theta_H$ = 120 °C – Θ_A = 90 °C. The three highest temperatures for the normal loading cycle are just over 90.3 °C; therefore, $\Delta\Theta_{TO} + \Delta\Theta_H$ = 60.3 °C.

To estimate what load multiplier K should be to produce $\Delta\Theta_{TO} + \Delta\Theta_H$ = 90 °C, we proceed as follows:

$$\left[\frac{\left(K^2R+1\right)}{(R+1)}\right]^n = \frac{90}{60.3}$$

where

K is the ratio of load L to rated load, per unit
n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.
R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

and solving for K gives

K = 1.26

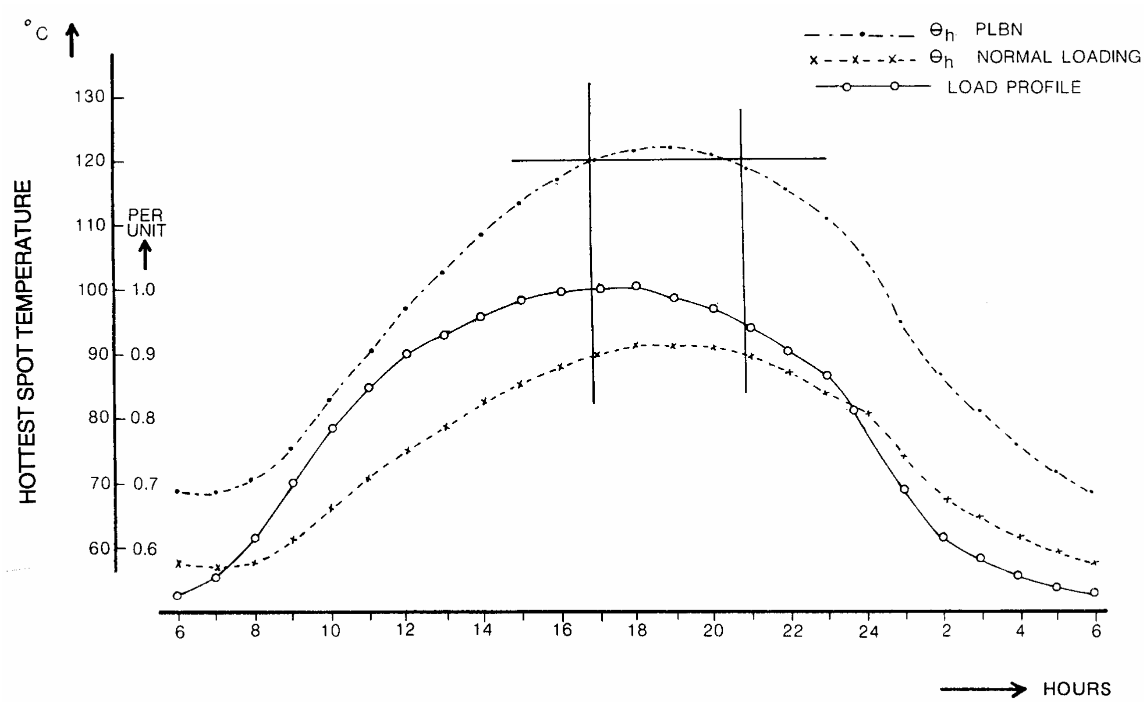

Figure C.1— Load cycles for normal loading and planned loading beyond nameplate

The top-oil rise is not quite proportional to the square of the load current (no-load losses are constant) but the winding gradient is proportional to the square of the load current. The multiplier may have to be corrected if it is unsatisfactory. Again we have to estimate an initial top-oil temperature. Following the same procedures as for the normal load, we obtain a temperature profile, based on the load cycle shown in Figure C.1. The hottest-spot temperature is in the 120–130 °C range for close to 4 h.

C.4 Long-time emergency loading (LTE)

A user has to consider carefully the emergency loading conditions that may occur on his system. A maximum period of 6 h is used in our example. Assume that the long time emergency begins at 13:00 h, and was preceded by a PLBN loading. Suppose a load multiplier of value K_2 is applied.

At 13:00 h:

$\Delta\Theta_{TO,i}$ = 33.90 °C, which is equal to $\Delta\Theta_{TO}$ in the PLBN loading. Apply Equation (C.2) to find this value.

At 14:00 h:

$$\Delta\Theta_{TO} = \left(7.42 \times 0.93 K_2^2\right) + 1.53 + \left(0.75 + 34.14\right) = 6.42 K_2^2 + 27.14$$

$$\Delta\Theta_H = \left(28.6 \times 0.96 K_2^2\right) = 26.36 K_2^2$$

At 15:00 h:

$$\Delta\Theta_{TO} = \left(7.42 \times 0.96 K_2^2\right) + 1.53 + \left(0.75\right)\left(6.42 K_2^2 + 27.14\right) = 11.66 K_2^2 + 21.89$$

$$\Delta\Theta_H = 27.47 K_2^2$$

Repeated application of Equation (C.2) finally gives at 19:00 h an equation for $\Delta\Theta_{TO}$ and $\Delta\Theta_H$ in terms of K_2 as follows:

$$\Delta\Theta_{TO} = \Delta\Theta_H = 51.25K_2^2 + 11.11$$

The LTE constraint is 140 °C, thus,

$$51.25K_2^2 + 11.11 + 30 = 140.0$$

and

$K_2 = 1.39$

Table C.1 shows the top-oil rise and the winding gradient. At 13:00 h and at 19:00 h, there is a discontinuity in current. The winding time-constant usually is in the order of 3–5 min. After 20 min, ΔT_{HS} will be according to the new load. Figure C.2 shows the hottest-spot temperature profile. The 140 °C temperature limitation has been met. The hottest-spot temperature is in the 130–140 °C range less than 6 h and in the 120–130 °C range longer than 4 h, so a value of 1.39 applied to the per-unit load from 13:00–19:00 hours seems to be in order.

C.5 Short-time emergency (STE) loading

In our example, an STE loading is assumed to occur at 13:00 h, following a PLBN loading. After 1/2 h, the load is reduced to the LTE loading, which will persist for 5.5 h. We will use an interval load value K_3. The STE constraint is a maximum hottest-spot temperature of 180 °C.

At 13:00 h:

$$\Delta\Theta_{TO,i} = 34.14^\circ C$$

Apply Equation (C.3) (for t = 0.5 h) to obtain at 13:30 h

$$\Delta\Theta_{TO} = 3.98K^2 + 0.82 + 0.87(34.14)$$

$$\Delta\Theta_H = 28.6K_3^2$$

$$\Theta_H = \Delta\Theta_{TO} + \Delta\Theta_H + \Theta_A = 32.58K_3^2 + 30.52 + 30.0 + 180.0$$

where

K_3	is the ratio of load L to rated load, per unit
Θ_A	is the average ambient temperature during the load cycle to be studied, °C
Θ_H	is the winding hottest-spot temperature, °C
$\Delta\Theta_H$	is the winding hottest-spot rise over top-oil temperature, °C
$\Delta\Theta_{TO}$	is the top-oil rise over ambient temperature, °C

K_3= 1.92

At 13:30 h: $\Delta\Theta_{TO}$ = 45.19 °C, $\Delta\Theta_H$ = 105.43 °C, Θ_H = 180.6 °C, load = 1.29 per unit

At 14:00 h: $\Delta\Theta_{TO} = (3.98)\ (1.29)^2 + 0.82 + (0.870)\ (45.19) = 46.76\ °C$

Figure C.2 shows the temperature excursion to be within the limits for the STE loading. The hottest-spot temperature will be somewhat longer in the 130–140 °C range limit.

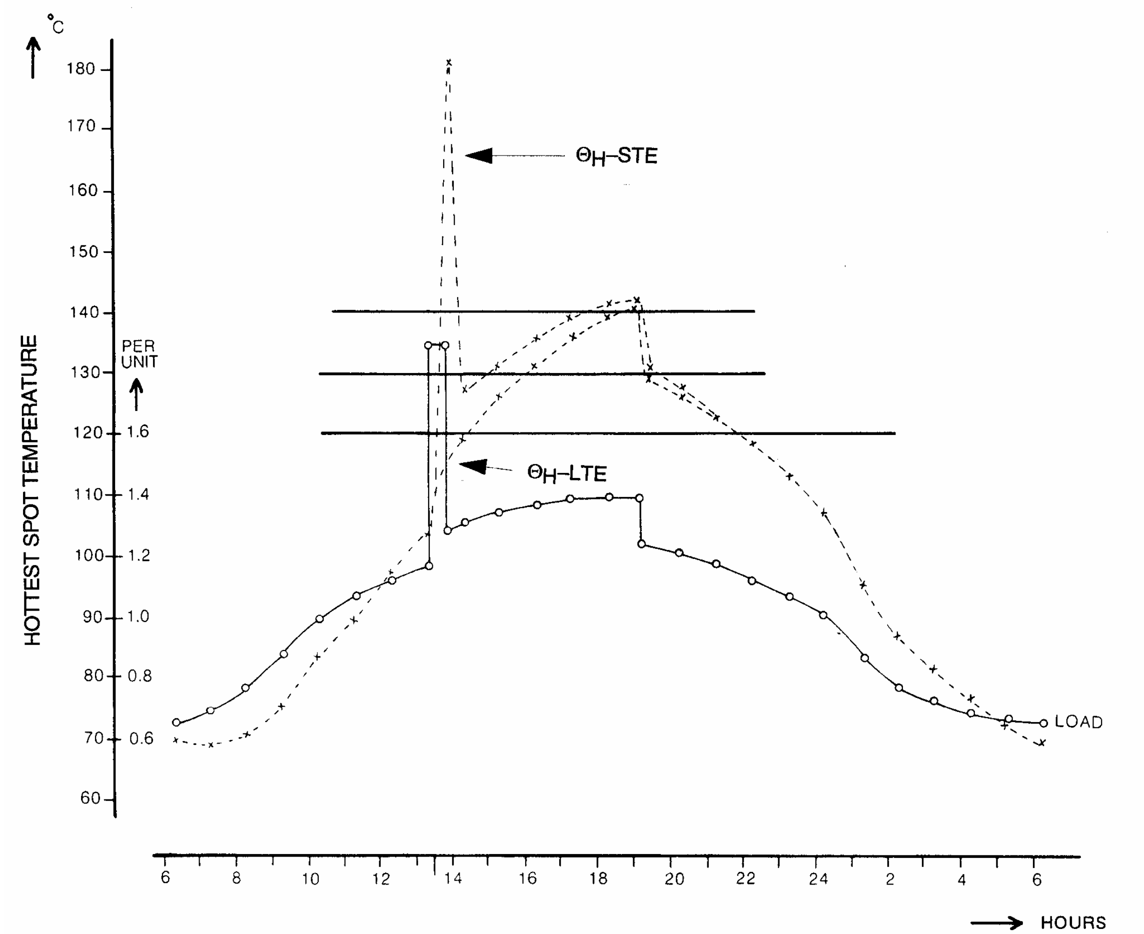

Figure C.2—Hottest-spot temperature profile for long time and short time emergency loading

Annex D

(normative)

Philosophy of guide applicable to transformers with 55 °C average winding rise (65 °C hottest-spot rise) insulation systems

D.1 General

Loading of transformers above nameplate is a controversial subject. Agreement on the loading limits can be agreed upon with the manufacturer if they have been clearly specified prior to the design of the transformer. However, since there has been new knowledge gained in recent years concerning stray flux fields and their effects of metallic temperatures, it is desirable to confirm greater than nameplate load capabilities with the manufacturers of transformers on critical systems.

Some users have considerable experience in loading power transformers above nameplate using computer programs in conjunction with IEEE Std C57.92-1981 and NEMA TR98-1978. Since this approach deals with loss of life due to the effects of thermal aging of the windings, it should always be accompanied with due consideration given to the load capabilities of all other components in the transformer. These components include bushings, tap-changers and terminal boards, current transformers, and leads. Relay settings should also be checked so that load is not dumped. Consideration should also be given to oil expansion and its effect on possible mechanical relief device operation, subsequent possible operation of the fault-pressure relay, and oil clogging of breathing devices. Forced-oil cooler fouling should also be a consideration when determining load capability. This fouling is particularly found in areas having salt spray environments or dust and chemical contaminants present. These computer programs should be modified to reflect this new loading guide where its use may lead to more conservative loading. The loss of a single transformer of over 100 MVA rating rarely causes power interruption of customers. However, loss of one transformer due to its failure or due to the failure of some other part in the electrical circuit can result in increased loading of the back-up transformers. Most utilities do not design for second contingencies without loss of load. The adverse consequences are therefore rather great if the increased loading of the back-up transformer results in a failure.

Common sense and good planning are required to keep the economic gains in balance with the risks of failure. Because excessive transformer temperatures weaken the insulation structures physically, and because many of the older transformers have low impedances, short-circuit failures should also be considered. The types of transformer construction are a factor in making this assessment. Most utilities load these transformers conservatively. Gas evolution in power transformers is not a new insulation contaminant. There are at least eight causes of gas within the transformer that have been documented. The risk of having a failure due to free gas in the insulating structure should take into consideration the insulation margins used and the construction of the insulation structures. The risk of failure increases considerably when the insulation levels are reduced three full steps from a typically accepted level such as use of 650 kV BIL on 230 kV transformers. The risk decreases when no insulation collars are used in highly stressed parts of these transformers with reduced BIL. Knowledgeable transformer engineers have paid close attention to gas evolution when specifying and designing these transformers.

The loading of transformers without thermally upgraded insulation (from an insulation aging point of view) can be considered to be similar to transformers with thermally upgraded insulation. The calculation of temperatures included in Clause 7 and Annex G may be applied equally well for transformers without thermally upgraded insulation. Equation (3) in Clause 5 gives the equation to calculate equivalent aging and loss of life for transformers with 55 °C rise insulation systems. The normal loss of life ratings are loadings that result in a daily loss of life equal to that of a continuous winding hottest-spot temperature of 95 °C for 55 °C rise transformers.

The factor that determines the greatest risk associated with loading transformers above nameplate rating is the evolution of free gas from the insulation of winding and lead conductors. This gas will result from the following two major sources:

a) *Vaporization of water contained in the insulation*. This process is discussed in Annex A of this guide.

b) *Thermal decomposition of cellulose*. Data on the constituent gases and their proportions released by thermal decomposition of both thermally up-graded and non-upgraded cellulose insulation may be found in many of the references in the bibliographies for Annex A and Annex I.

D.2 Aging equations

For older transformers with 55 °C average winding rise insulation systems with a rated hottest-spot rise over ambient of 65 °C and a 30 °C ambient, the reference temperature is 95 °C. The equations for per-unit life and the aging acceleration factor are as follows:

$$\text{Per unit life} = 2.00 \times 10^{-10}\, e^{\left[\frac{15000}{\Theta_H + 273}\right]} \tag{D.1}$$

where

Θ_H is the winding hottest-spot temperature, °C

$$F_{AA} = e^{\left[\frac{15000}{368} - \frac{15000}{\Theta_H + 273}\right]} \tag{D.2}$$

where

F_{AA} is the aging acceleration factor
Θ_H is the winding hottest-spot temperature, °C

Annex E

(normative)

Unusual temperature and altitude conditions

E.1 Unusual temperatures and altitude

Transformers may be applied at higher ambient temperatures or at higher altitudes than specified in IEEE Std C57.12.00, but performance may be affected, and special consideration should be given to these applications.

E.2 Effect of altitude on temperature rise

The effect of the decreased air density due to high altitude is to increase the temperature rise of transformers since they are dependent upon air for the dissipation of heat losses.

E.3 Operation at rated kVA

Transformers may be operated at rated kVA at altitudes greater than 1000 m (3300 ft) without exceeding temperature limits, provided the average temperature of the cooling air does not exceed the values of Table E.1 for the respective altitudes.

a) See 4.3.2 and Table 1 in IEEE Std C57.12.00-2010 for corrections of transformer insulation capability at altitudes above 1000 m (3300 ft).

b) Operation in low ambient temperature with the top liquid at a temperature lower than –20 °C may reduce dielectric strength between internal energized components below design levels.

E.4 Operation at less than rated kVA

Transformers may be operated at altitudes greater than 1000 m (3300 ft) without exceeding temperature limits, provided the load to be carried is reduced below rating by the percentages given in Table E.2 for each 100 m (330 ft) and that the altitude is above 1000 m (3300 ft).

Table E.1—Maximum allowable average temperature[a] of cooling air for carrying rated kVA

Method of cooling apparatus	1000 m (3300 ft)	2000 m (6600 ft)	3000 m (9900 ft)	4000 m (13200 ft)
Liquid-immersed self-cooled	30	28	25	23
Liquid-immersed forced-air-cooled	30	26	23	20
Liquid-immersed forced-oil-cooled with oil-to-air cooler	30	26	23	20

[a] It is recommended that the average temperature of the cooling air be calculated by averaging 24 consecutive hourly readings. When the outdoor air is the cooling medium, the average of the maximum and minimum daily temperatures may be used. The value obtained in this manner is usually slightly higher by not more than 0.3 °C than the true daily average.

Table E.2—Rated kVA correction factors for altitudes greater than 1000 m (3300 ft)

Types of cooling	Derating factor% per 100m (330 ft)
Liquid-immersed air-cooled	0.4
Liquid-immersed water-cooled	0.0
Liquid-immersed forced-air-cooled	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-air cooler	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-water-cooler	0.0

E.5 Bibliography for Annex E

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Annex F

(normative)

Cold-load pickup (CLPU)

F.1 General

Cold-load pickup (CLPU) is the loading imposed on power and distribution transformers upon re-energization following a system outage. When an outage occurs, temperature in residential and office buildings starts to decay towards the outdoor ambient temperature. The amount of this decay and heat loss depends upon the temperature differential, the building insulation level, etc. Diversity among all the electric space heating furnaces and other appliances is rapidly lost. When the power is restored, all connected electric space heating furnaces, heaters, and other appliances will demand power simultaneously until the normal temperature conditions are attained and the diversity is regained. The time required to regain the diversity depends on the heating capacity of the furnaces and the duration of the preceding outage.

Obviously, the total loading imposed on the transformer after power restoration will be substantially higher than its normal peak load. Cold-load pickup consists of the following two components of the restoration load:

a) Inrush current associated with transformers, motor starting, etc. Although the magnitudes are quite large (in the order of 6 to 25 times the normal current), the duration is quite short, lasting a few cycles.

b) Load due to loss of diversity among thermostatically controlled cycling appliances. This load may persist for tens of minutes.

F.2 Duration of loads

Duration of this excessive load depends upon several variables, some of which are as follows:

— Time of and the day the outage begins – Day of the week outage ends
— Duration of outage
— Temperature conditions and wind
— Number of customers affected by the outage – Building size and insulation levels
— Type of load

This loading condition will persist until all the thermostatically controlled appliances are satisfied and the diversity has been restored. Typically, the maximum length of time during an outage until all diversity will be lost is around 20 min. The longer the outage lasts, the longer the load will remain undiversified after re-energization.

F.3 CLPU ratio

The ratio of the post-interruption load to pre-interruption load varies with the length and time of day of the interruption and the ambient temperature during interruption.

As an example, CLPU ratios that may be expected in a utility are as follows:

Load type	CLPU ratio
Major industrial	Less than 1.0
Residential plus 50% industrial	1–1.5
Urban residential plus less than 20% penetration of electric	1.5–2.0
Combination urban and rural	2.0–2.5
Rural	2.5–3.0

Different users will have different CLPU ratios depending upon their own customers and operating practices. Each user should look at the ratios for his or her system.

Studies (such as *Effects of the Cold Load Pickup at the Distribution Substation Transformer* [F2]) have shown that CLPU with high penetration of electric heating can become a limiting factor for substation transformers and for the protective equipment on the feeder. Electric heat penetration of 50–70% could lead to a CLPU ratio in the range of 3–4, or even higher.

Air conditioning could become a limiting factor if the penetration of air conditioning loads exceeds electric resistance space heating by a factor of 3 or more.

Depending upon normal loading of the transformer, it is possible to reach short-term emergency loading limits of the substation transformer. In some cases, it is possible for CLPU to exceed the thermal limits of a transformer resulting in associated loss of transformer insulation life.

During these types of loads, the auxiliary cooling equipment should be in operation. Since the duration of these loads is short or does not occur often, it is recommended that CLPU be considered as short-time emergency loading of the transformer.

F.4 Other considerations

Although CLPU has not been recognized as a serious problem in the past, changing patterns of oil and gas price and availability in several parts of the country have resulted in a continuing changeover from oil-based heating system to electric space heating system, making CLPU a more serious problem. In the substations where the transformers may be approaching their nameplate loading, it is worthwhile investigating the type of loads served to determine if a CLPU problem exists.

Depending upon circumstances, it may be necessary to restore the load in stages.

The effect of CLPU should be considered in the setting of relays, recloser trip settings, and fuse sizes to prevent nuisance tripping.

When planning capacity additions, utilities normally select the transformer capabilities to accommodate the anticipated load growth. It is recommended that effects of CLPU should also be considered during this planning. Application of loads in excess of nameplate when ambient temperatures are less than 0 °C requires consideration of transformer design, cooling control, and prior loading. Viscosity of the insulation fluid will influence velocity and distribution, and may detrimentally affect heat transfer. For power transformers with external cooling accessories, the method of control should be reviewed to ensure oil flow is induced before loading exceeds the respective ratings. If prior loading cannot be controlled by demand or rate of increase, the windings may experience localized hot spots and accelerated aging of conductor insulation during cold weather ambients.

F.5 Bibliography for Annex F

[F1] Aubin and Langhame, T., *Effect of Oil Viscosity on Transformer Loading Capability at Low Ambient Temperatures*, IEEE Transactions on Power Delivery, vol. 7 no. 2, pp. 516–524, April 1992.

[F2] *Effects of Cold Load Pickup at the Distribution Substation Transformer*, Canadian Electrical Association (CEA), Report 131D 247, Nov. 1988.

[F3] Wilde, R.L., *Effects of Cold Load Pickup at the Distribution Substation Transformer*, IEEE Transactions on Power Apparatus and Systems, vol. PAS-104, no. 3, Mar. 1985.

[F4] Wilde, R. L., *Effects of Cold Load Pickup on Distribution Transformers*, IEEE Transactions on Power Apparatus and Systems, vol. PAS-100, no. 5 May 1981.

Annex G

(informative)

Alternate temperature calculation method

G.1 General

The transformer loading equations in Clause 7 use the top-oil temperature rise over ambient to determine the winding hottest-spot temperature during an overload. When the equations were first proposed in 1945, there were few experimental investigations of the winding hottest-spot temperature during transient loading conditions. Recent investigations (Aubin and Langhame [G4], Pierce [G7]) have shown that during overloads, the temperature of the oil in the winding cooling ducts rises rapidly at a time constant equal to the winding. During this transient condition, the oil temperature adjacent to the hot spot location is higher than the top oil temperature in the tank. For the ONAN and ONAF cooling modes, this phenomena results in winding hottest-spot temperatures greater than predicted by the equations of Clause 7. Accurate predictions of the winding hottest-spot temperature require the use of the temperature of the oil entering and exiting the winding cooling ducts. The equations presented in this annex consider type of liquid, cooling mode, winding duct oil temperature rise, resistance and viscosity changes, and ambient temperature and load changes during a load cycle. The derivation of the equations is given in Pierce [G8]. A PC Basic computer program is presented to perform the calculations in a step-by-step procedure.

Although the equations more exactly describe the heat transfer and fluid flow phenomena occurring in a liquid-immersed transformer during transient loading, they may not be equally valid for all distribution and power transformers covered by this guide and for all loading conditions. Recent research using imbedded thermocouples and fiber optic detectors indicate that the fluid flow occurring in the winding during transient heating and cooling is an extremely complicated phenomena to describe by simple equations. Research in this field is ongoing at this time and may be incorporated into future revisions of this guide.

G.2 List of symbols

Temperatures are indicated by Θ, and temperature rises or temperature differences are indicated by $\Delta\Theta$.

Equation	Program	Description
—	A	Aging acceleration factor
—	AEQ	Equivalent aging acceleration factor over a complete load cycle
—	ASUM	Equivalent insulation aging over load cycle, h
—	AMB( )	Ambient point on input of load cycle curve, °C
D	B	Constant in viscosity equation
G	C	Constant in viscosity equation
Cp_{CORE}	—	Specific heat of core, W-min/lb °C
Cp_{OIL}	CPF	Specific heat of fluid, W-min/lb °C
—	CPST	Specific heat of steel, W-min/lb °C
Cp_{TANK}	—	Specific heat of tank, W-min/lb °C
Cp_W	CPW	Specific heat of winding material, W-min/lb °C
E_{HS}	PUELHS	Eddy loss at winding hot spot location, per unit of I^2R loss

Equation	Program	Description
—	GFLUID	Fluid volume, gallons
H_{HS}	HHS	Per unit of winding height to hot spot location
—	JJ	Number of points on load cycle
I_R	—	Rated current, A
K_{HS}	TKHS	Temperature correction for losses at hot spot location
—	KK	Number of times results are printed
K_W	TKW	Temperature correction for losses of winding
—	LCAS	Loading case 1 or 2, see input data description in G.5
K	PL	ratio of load L to rated load, per unit
—	PUL( )	Per-unit load point on load cycle curve
—	MA	Cooling code, 1 = ONAN, 2 = ONAF, 3 = non-directed OFAF, 4 = directed ODAF
—	MC	Conductor code, l = aluminum, 2 = copper
—	MCORE	Core overexcitation occurs during load cycle, 0 = no, l = yes
—	MF	Fluid code, 1= mineral oil, 2 = silicone, 3 = HTHC
—	MPR1	Print temperature table, 0 = no, 1 = yes
—	MPR	Print temperature table, 0 = no, 1 = yes
M_{CC}	WCC	Core and coil (untanking) weight, lb
M_{CORE}	WCORE	Mass of core, lb
M_{OIL}	WFL	Mass of fluid, lb
M_{TANK}	WTANK	Mass of tank, lb
M_W	WWIND	Mass of windings, lb
$M_W Cp_W$	XMCP	Winding mass times specific heat, W-min/°C
ΣMCp	SUMMCP	Total mass times specific heat of fluid, tank, and core, W-min/°C
$P_{C,R}$	PC	Core (no-load) loss, W
$P_{C,OE}$	PCOE	Core loss when overexcitation occurs, W
P_E	PE	Eddy loss of windings at rated load, W
P_{EHS}	PEHS	Eddy loss of windings at rated load and rated winding hot-spot temperature, W
P_S	PS	Stray losses at rated load, W
P_T	PT	Total losses at rated load, W
P_W	PW	Winding I^2R loss at rated load, W
P_{HS}	PWHS	Winding I^2R loss at rated load and rated hot-spot temperature, W
Q_C	QC	Heat generated by core, W-min
$Q_{GEN,HS}$	QHSGEN	Heat generated at hot spot temperature, W-min
$Q_{GEN,W}$	QWGEN	Heat generated by windings, W-min

Equation	Program	Description
$Q_{LOST,\ HS}$	QLHS	Heat lost for hot-spot calculation, W-min
$Q_{LOST,\ O}$	QLOSTF	Heat lost by fluid to ambient, W-min
$Q_{LOST,\ W}$	QWLOST	Heat lost by winding, W-min
Q_S	QS	Heat generated by stray losses, W-min
—	RHOF	Fluid density, lb/in^3
—	SL	Slope of line between two load points of load cycle curve
—	SLAMB	Slope of line between two ambient temperature points of load cycle curve
Δt	DT	Time increment for calculation, min
—	DTP	Time increment for printing calculations, min
—	TIM( )	Value of time point on load cycle
—	TIMHS	Time during load cycle when maximum hot spot occurs, h
—	TIMP( )	Times when results are printed, min
—	TMP	Time to print a calculation, min
—	TIMCOR	Time when core overexcitation occurs, h
—	TIMTO	Time during load cycle when maximum top oil temperature occurs, h
—	TIMS	Elapsed time, min
	TIMSH	Elapsed time, h
x	X	Exponent for duct oil rise over bottom oil, 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF
y	YN	Exponent of average fluid rise with heat loss, 0.8 for ONAN, 0.9 for ONAF and OFAF, 1.0 for ODAF
z	Z	Exponent for top to bottom fluid temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF
Θ	T	Temperature to calculate viscosity, °C
Θ_A	TA	Ambient temperature, °C
$\Theta_{A,R}$	TAR	Rated ambient at kVA base for load cycle, °C
Θ_{BO}	TBO	Bottom fluid temperature, °C
$\Theta_{BO,R}$	TBOR	Bottom fluid temperature at rated load, °C
Θ_{DAO}	TDAO	Average temperature of fluid in cooling ducts, °C
$\Theta_{DAO,R}$	TDAOR	Average temperature of fluid in cooling ducts at rated load, °C
Θ_{TDO}	TTDO	Fluid temperature at top of duct, °C
$\Theta_{\mathrm{TDO,R}}$	TTDOR	Fluid temperature at top of duct at rated load, °C
Θ_{H}	THS	Winding hottest-spot temperature, °C
—	THSMAX	Maximum hottest-spot temperature during load cycle, °C
$\Theta_{H,R}$	THSR	Winding hottest-spot temperature at rated load, °C
Θ_{K}	TK	Temperature factor for resistance correction, °C
—	TKHS	Correction factor for correction of losses to hot-spot temperature

Equation	Program	Description
—	TKVA1	Temperature base for losses at base kVA input, °C
—	TMU	Temperature in viscosity function, °C
Θ_{AO}	TFAVE	Average fluid temperature in tank and radiator, °C
—	TFAVER	Average fluid temperature in tank and radiator at rated load, °C
Θ_{TO}	TTO	Top fluid temperature in tank and radiator, °C
—	TTOMAX	Maximum top fluid temperature in tank during load cycle, °C
$\Theta_{TO,R}$	TTOR	Top fluid temperature in tank and radiator at rated load, °C
Θ_{W}	TW	Average winding temperature, °C
Θ_{WO}	TWO	Temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO,R}$	TWOR	Temperature of oil adjacent to winding hot spot at rated load, °C
—	TWR	Rated Average winding temperature at rated load, °C
$\Theta_{W,R}$	TWRT	Average winding temperature at rated load tested, °C
$\Delta\Theta_{AO,R}$	—	Average oil rise over ambient at rated load, °C
$\Delta\Theta_{BO}$	—	Bottom fluid rise over ambient, °C
$\Delta\Theta_{BO,R}$	THEBOR	Bottom fluid rise over ambient at rated load, °C
$\Delta\Theta_{DO,R}$	THEDOR	Temperature rise of fluid at top of duct over ambient at rated load, °C
$\Delta\Theta_{DO/BO}$	DTDO	Temperature rise of fluid at top of duct over bottom fluid, °C
$\Delta\Theta_{H/A}$	THEHSA	Winding hottest-spot rise over ambient, °C
$\Delta\Theta_{H/WO}$	—	Winding hot-spot temperature rise over oil next to hot-spot location, °C
$\Delta\Theta_{T/B}$	DTTB	Temperature rise of fluid at top of radiator over bottom fluid, °C
$\Delta\Theta_{TO}$	—	Top fluid rise over ambient, °C
$\Delta\Theta_{TO,R}$	THETOR	Top fluid rise over ambient at rated load, °C
—	THKVA2	Rated ave. winding rise over ambient at kVA base of load cycle, °C
$\Delta\Theta_{W/A,R}$	THEWA	Tested or rated average winding rise over ambient, °C
$\Delta\Theta_{WO/BO}$	—	Temperature rise of oil at winding hot-spot location over bottom oil, °C
μ	FNV(B,C,T)	Viscosity, cP
μ_{HS}	VISHS	Viscosity of fluid for hot-spot calculation, cP
$\mu_{\mathrm{HS,R}}$	VIHSR	Viscosity of fluid for hot-spot calculation at rated load, cP
μ_{W}	VIS	Viscosity of fluid for average winding temperature rise calc., cP
$\mu_{W,R}$	VISR	Viscosity of fluid for average winding temperature rise at rated load, cP
τ_{W}	TAUW	Winding time constant, min
—	XKVA1	kVA base for losses in input data
—	XKVA2	kVA base for load cycle curve

Suffixes	**Description**
1	At the prior time
2	At the next instant of time
R	At rated load
/	Over
Superscript	**Description**
(')	Indicates adjustment of test report data for a different tap position

Cooling modes	**Description**
ONAN	Natural convection flow of oil through windings and radiators. Natural convection flow of air over tank and radiators.
ONAF	Natural convection flow of oil through windings and radiators. Forced convection flow of air over radiators by fans.
ODAF	Forced oil flow through windings and radiators or heat exchanger by pumps. The oil is directed from the radiators or heat exchangers into the windings. The air is forced over the radiators or heat exchanger by fans.
OFAF	Forced oil flow through the radiators by one or more pumps. The oil is forced to flow into the tank by the pumps; however the main forced oil flow in the tank bypasses the windings. The air is forced over the radiators or heat exchangers by fans.

G.3 Equations

G.3.1 Introduction

The winding hottest-spot and oil temperatures are obtained from equations for the conservation of energy during a small instant of time, Δt. The system of equations constitutes a transient forward-marching finite difference calculation procedure. The equations were formulated so that temperatures obtained from the calculation at the prior time t_1 are used to compute the temperatures at the next instant of time $t_1 + \Delta t$ or t_2. The time is incremented again by Δt, and the last calculated temperatures are used to calculate the temperatures for the next time step. At each time step, the losses were calculated for the load and corrected for the resistance change with temperature. Corrections for fluid viscosity changes with temperature were also incorporated into the equations. With this approach, the required accuracy is achieved by selecting a small value for the time increment Δt and the programming approach is very simple. No iteration is required.

The improved system of loading equations is based on the fluid flow conditions occurring in the transformer during transient conditions. The hottest-spot temperature is made up of the following components.

$$\Theta_H = \Theta_A + \Delta\Theta_{BO} + \Delta\,\Theta_{WO/BO} + \Delta\,\Theta_{H/WO} \tag{G.1}$$

where

Θ_A	is the average ambient temperature during the load cycle to be studied, °C
Θ_H	is the winding hottest-spot temperature, °C
$\Delta\Theta_{BO}$	is the bottom fluid rise over ambient, °C
$\Delta\Theta_{WO/BO}$	is the temperature rise of oil at winding hot-spot location over bottom oil, °C
$\Delta\Theta_{H/WO}$	is the winding hot-spot temperature rise over oil next to hot-spot location, °C

The energy balance equation to determine the oil temperature was based on the average oil temperature in the tank and radiators. The temperatures of the top and bottom oil are determined from Equation (G.2) and Equation (G.3).

$$\Theta_{BO} = \Theta_{AO} - \frac{\Delta\Theta_{T/B}}{2} \tag{G.2}$$

$$\Theta_{TO} = \Theta_{AO} + \frac{\Delta\Theta_{T/B}}{2} \tag{G.3}$$

where

Θ_{AO}	is the average fluid temperature in tank and radiator, °C
Θ_{BO}	is the bottom fluid temperature, °C
Θ_{TO}	is the top fluid temperature, °C
$\Delta\Theta_{T/B}$	is the temperature rise of fluid at top of radiator over bottom fluid, °C

For overload conditions, the oil temperature rise at the hottest-spot location $\Delta\Theta_{WO/BO}$ is the temperature rise of the oil in the winding cooling ducts above the bottom oil temperature. When the load is reduced, the winding duct oil temperature falls, but a portion of the upper winding may still remain in the hotter top oil of the main tank. When the winding duct oil temperature is less than the top oil in the main tank, $\Delta\Theta_{WO/BO}$ is assumed to equal the tank top-oil rise over the bottom oil.

G.3.2 Average winding temperature

The heat generated by the windings during the time t_1 to t_2 is

$$Q_{GEN,W} = K^2 \left[P_W K_W + \frac{P_E}{K_W} \right] \Delta t \tag{G.4}$$

where

K	is the ratio of load L to rated load, per unit
K_W	is the temperature correction for losses of winding
P_E	is the eddy loss of windings at rated load, W
P_W	is the winding I^2R loss at rated load, W
$Q_{GEN,W}$	is the heat generated by windings, W-min
Δt	is the time increment for calculation, min

where

$$K_W = \frac{\Theta_{W,1} + \Theta_K}{\Theta_{W,R} + \Theta_K} \tag{G.5}$$

where

K_W	is the temperature correction for losses of winding
Θ_K	is the temperature factor for resistance correction, °C
$\Theta_{W,1}$	is the average winding temperature at the prior time, °C
$\Theta_{W,R}$	is the average winding temperature at rated load tested, °C

For the ONAN, ONAF, and OFAF cooling modes, the heat lost by the windings is

$$Q_{LOST,W} = \left[\frac{\Theta_{W,1} - \Theta_{DAO,1}}{\Theta_{W,R} - \Theta_{DAO,R}}\right]^{5/4} \left[\frac{\mu_{W,R}}{\mu_{W,1}}\right]^{1/4} (\,P_W + P_E\,)\,\Delta t \tag{G.6A}$$

where

P_E	is the eddy loss of windings at rated load, W
P_W	is the winding I^2R loss at rated load, W
$Q_{LOST,\,W}$	is the heat lost by winding, W-min
$\Theta_{DAO,1}$	is the average temperature of fluid in cooling ducts at the prior time, °C
$\Theta_{DAO,R}$	is the average temperature of fluid in cooling ducts at rated load, °C
$\Theta_{W,1}$	is the average winding temperature at the prior time, °C
$\Theta_{W,R}$	is the average winding temperature at rated load tested, °C
Δt	is the time increment for calculation, min
$\mu_{W,1}$	is the viscosity of fluid for average winding temperature rise at rated load at the prior time, cP
$\mu_{W,R}$	is the viscosity of fluid for average winding temperature rise at rated load, cP

The viscosity μ is evaluated at a temperature equal to the average winding temperature plus the average oil duct temperature divided by two.

For the ODAF cooling mode, no viscosity correction is used since the fluid is pumped and the heat lost is

$$Q_{LOST,W} = \left[\frac{\Theta_{W,1} - \Theta_{DAO,1}}{\Theta_{W,R} - \Theta_{DA(O,R)}}\right] (\,P_W + P_E\,)\,\Delta t \tag{G.6B}$$

where

P_E	is the eddy loss of windings at rated load, W
P_W	is the winding I^2R loss at rated load, W
$Q_{LOST,\,W}$	is the heat lost by winding, W-min
$\Theta_{DAO,1}$	is the average temperature of fluid in cooling ducts at the prior time, °C
$\Theta_{DAO,R}$	is the average temperature of fluid in cooling ducts at rated load, °C
$\Theta_{W,1}$	is the average winding temperature at the prior time, °C
$\Theta_{W,R}$	is the average winding temperature at rated load tested, °C
Δt	is the time increment for calculation, min

The mass and thermal capacitance of the windings may be estimated from the winding time constant. The winding time constant may be determined from the cooling curves obtained during factory heat run testing, or approximate values may be used. From the definition of a time constant for exponential heating or cooling the MCp term may be determined from Equation (G.7).

$$M_W Cp_W = \frac{(P_W + P_E)\,\tau_W}{\Theta_{W,R} - \Theta_{DAO,R}} \qquad \text{(G.7)}$$

where

$M_W Cp_W$	is the winding mass times specific heat, W-min/°C
P_E	is the eddy loss of windings at rated load, W
P_W	is the winding I^2R loss at rated load, W
$\Theta_{DAO,R}$	is the average temperature of fluid in cooling ducts at rated load, °C
$\Theta_{W,R}$	is the average winding temperature at rated load tested, °C
τ_W	is the winding time constant, min

The average winding temperature at time $t = t_2$ is

$$\Theta_{W,2} = \frac{Q_{GEN,W} - Q_{LOST,W} + M_W Cp_W\, \Theta_{W,1}}{M_W Cp_W} \qquad \text{(G.8)}$$

where

$M_W Cp_W$	is the winding mass times specific heat, W-min/°C
$Q_{GEN,W}$	is the heat generated by windings, W-min
$Q_{LOST,W}$	is the heat lost by winding, W-min
$\Theta_{W,1}$	is the average winding temperature at the prior time, °C
$\Theta_{W,2}$	is the average winding temperature at the next instant of time, °C

G.3.3 Winding duct oil temperature rise over bottom oil

$$\Delta\Theta_{DO/BO} = \Theta_{TDO} - \Theta_{BO} = \left[\frac{Q_{LOST,W}}{(P_W + P_E)\,\Delta t}\right]^x (\Theta_{TDO,R} - \Theta_{BO,R}) \qquad \text{(G.9)}$$

where

P_E	is the eddy loss of windings at rated load, W
P_W	is the winding I^2R loss at rated load, W
$Q_{LOST,W}$	is the heat lost by winding, W-min
x	is the exponent for duct oil rise over bottom oil, and is 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF
Θ_{BO}	is the bottom fluid temperature, °C
$\Theta_{BO,R}$	is the bottom fluid temperature at rated load, °C
Θ_{TDO}	is the fluid temperature at top of duct, °C
$\Theta_{TDO,R}$	is the fluid temperature at top of duct at rated load, °C
$\Delta\Theta_{DO/BO}$	is the temperature rise of fluid at top of duct over bottom fluid, °C
Δt	is the time increment for calculation, min

For the ONAN, ONAF, and ODAF cooling modes the duct top-oil temperature at rated load, $\Theta_{TDO,R}$ is assumed equal to the tank top oil temperature. For non-directed OFAF, if the duct top-oil temperature at rated load $\Theta_{TDO,R}$ is not known, it can be assumed to be approximately equal to the average winding temperature at rated load (based on an analysis of the data reported in Pierce [G7]).

In Pierce [G7], it is shown that the hot spot may not be located at the top of the winding. The oil temperature at the hot-spot elevation is given by

$$\Delta\Theta_{WO/BO} = H_{HS}(\Theta_{TDO} - \Theta_{BO}) \quad \text{(G.10)}$$

$$\Theta_{WO} = \Theta_{BO} + \Theta_{WO/BO} \quad \text{(G.11A)}$$

where

H_{HS} is the per unit of winding height to hot spot location
Θ_{BO} is the bottom fluid temperature, °C
Θ_{TDO} is the fluid temperature at top of duct, °C
Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO/BO}$ is the temperature of oil at winding hot-spot location over bottom oil, °C
$\Delta\Theta_{WO/BO}$ is the temperature rise of oil at winding hot-spot location over bottom oil, °C

When the winding duct-oil temperature is less than the top oil in the tank, the oil temperature adjacent to the hot spot is assumed equal to the top-oil temperature since the upper portion of the winding may be in contact with the hotter top oil. The equation is as follows:

$$\text{IF } \Theta_{TDO} < \Theta_{TO} \text{ THEN } \Theta_{WO} = \Theta_{TO} \quad \text{(G.11B)}$$

Θ_{TDO} is the fluid temperature at top of duct, °C
Θ_{TO} is the top fluid temperature in tank and radiator, °C
Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C

G.3.4 Winding hottest-spot temperature

To account for the additional heat generated at the hot-spot temperature, it is necessary to correct the winding losses from the average winding temperature to the hottest-spot temperature by means of the following equations:

$$P_{HS} = \left(\frac{\Theta_{H,R} + \Theta_K}{\Theta_{W,R} + \Theta_K}\right) P_W \quad \text{(G.12)}$$

$$P_{EHS} = E_{HS}\, P_{HS} \quad \text{(G.13)}$$

where

E_{HS} is the eddy loss at winding hot spot location, per unit of I^2R loss
P_{EHS} is the eddy loss at rated load and rated winding hot-spot temperature, W
P_{HS} is the Winding I^2R loss at rated load and rated hot spot temperature, W
P_W is the winding I^2R loss at rated load, W
Θ_K is the temperature factor for resistance correction, °C
$\Theta_{H,R}$ is the winding hottest-spot temperature at rated load, °C
$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C

If E_{HS} is not known, it may be estimated; however, it should be equal to or greater than $P_{E,R}$ divided by $P_{W,R}$.

$$Q_{GEN,HS} = K^2 \left[P_{HS}\, K_{HS} + \frac{P_{EHS}}{K_{HS}} \right] \Delta t \quad \text{(G.14)}$$

where

K	is the ratio of load L to rated load, per unit
K_{HS}	is the temperature correction for losses at hot spot location
P_{EHS}	is the eddy loss at rated load and rated winding hot-spot temperature, W
P_{HS}	is the winding I^2R loss at rated load and rated hot spot temperature, W
$Q_{GEN,HS}$	is the heat generated at hot spot temperature, W-min
Δt	is the time increment for calculation, min

where

$$K_{HS} = \frac{\Theta_{H,1} + \Theta_K}{\Theta_{H,R} + \Theta_K} \tag{G.15}$$

where

K_{HS}	is the temperature correction for losses at hot spot location
Θ_K	is the temperature factor for resistance correction, °C
$\Theta_{H,1}$	is the winding hottest-spot temperature at rated load at the prior time, °C
$\Theta_{H,R}$	is the winding hottest-spot temperature at rated load, °C

For the ONAN, ONAF, and OFAF cooling modes, the heat lost at the hot spot location is given by

$$Q_{LOST,HS} = \left[\frac{\Theta_{H,1} - \Theta_{WO}}{\Theta_{H,R} - \Theta_{WO,R}}\right]^{5/4} \left[\frac{\mu_{HS,R}}{\mu_{HS,1}}\right]^{1/4} (P_{HS} + P_{EHS})\, \Delta t \tag{G.16A}$$

where

P_{EHS}	is the eddy loss at rated load and rated winding hot-spot temperature, W
P_{HS}	is the winding I^2R loss at rated load and rated hot spot temperature, W
$Q_{LOST,\,HS}$	is the heat lost for hot-spot calculation, W-min
$\Theta_{H,1}$	is the winding hottest-spot temperature at the prior time, °C
$\Theta_{H,R}$	is the winding hottest-spot temperature at rated load °C
Θ_{WO}	is the temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO,R}$	is the temperature of oil adjacent to winding hot spot at rated load, °C
$\mu_{HS,1}$	Is the viscosity of fluid for hot-spot calculation at the prior time, cP
$\mu_{HS,R}$	Is the viscosity of fluid for hot-spot calculation at rated load, cP
Δt	is the time increment for calculation, min

For the ODAF cooling mode, no viscosity correction is used since the oil is pumped and the heat lost at the hot-spot location is given by

$$Q_{LOST,HS} = \left[\frac{\Theta_{H,1} - \Theta_{WO}}{\Theta_{H,R} - \Theta_{WO,R}}\right] (P_{HS} + P_{EHS})\, \Delta t \tag{G.16B}$$

where

P_{EHS}	is the eddy loss at rated load and rated winding hot-spot temperature, W
P_{HS}	is the winding I^2R loss at rated load and rated hot spot temperature, W
$Q_{LOST,\,HS}$	is the heat lost for hot-spot calculation, W-min
$\Theta_{H,1}$	is the winding hottest-spot temperature at the prior time, °C
$\Theta_{H,R}$	is the winding hottest-spot temperature at rated load °C
Θ_{WO}	is the temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO,R}$	is the temperature of oil adjacent to winding hot spot at rated load, °C
Δt	is the time increment for calculation, min

The winding hot-spot temperature at time t_2 is

$$\Theta_{H,2} = \frac{Q_{GEN,HS} - Q_{LOST,HS} + M_W Cp_W \, \Theta_{H,1}}{M_W Cp_W} \tag{G.17}$$

where

$M_W Cp_W$	is the winding mass times specific heat, W-min/°C
$Q_{GEN,\ HS}$	is the heat generated at hot spot temperature, W-min
$Q_{LOST,\ HS}$	is the heat lost for hot-spot calculation, W-min
$\Theta_{H,1}$	is the winding hottest-spot temperature at the prior time, °C
$\Theta_{H,2}$	is the winding hottest-spot temperature at the next instant of time, °C

G.3.5 Average oil temperature

The heat lost by the windings to the duct oil and the heat generated by the core and stray losses is absorbed by the bulk oil in the main tank and radiators and is lost to the ambient air. The heat generated by the core varies slightly with temperature; however, it is assumed constant for the analysis. Overexcitation during the load cycle increases core loss however. The heat generated by the core is given by Equation (G.18A), Equation (G.18B), and Equation (G.19) as follows:

For normal excitation:

$$Q_C = P_{C,R} \, \Delta t \tag{G.18A}$$

where

$P_{C,R}$	is the core (no-load) loss, W
Q_C	is the heat generated by core, W-min
Δt	is the time increment for calculation, min

For overexcitation:

$$Q_C = P_{C,OE} \, \Delta t \tag{G.18B}$$

where

$P_{C,OE}$	is the core loss when overexcitation occurs, W
Q_C	is the heat generated by core, W-min
Δt	is the time increment for calculation, min

The heat generated by the stray loss is given by

$$Q_S = \left[\frac{K^2 P_S}{K_W} \right] \Delta t \tag{G.19}$$

where

K	is the ratio of load L to rated load, per unit
K_W	is the temperature correction for losses of winding
P_S	is the stray losses at rated load, W
Q_S	is the heat generated by stray losses, W-min
Δt	is the time increment for calculation, min

The temperature correction, K_W for stray loss is given by Equation (G.5) and assumes that the temperature of the structural parts is the same as the average winding temperature.

The heat lost by the oil is given by Equation (G.20) and Equation (G.21) as follows:

$$P_T = P_W + P_E + P_S + P_C \tag{G.20}$$

where

P_C is the core (no-load) loss, W
P_E is the eddy loss of windings at rated load, W
P_S is the stray losses at rated load, W
P_T is the total losses at rated load, W
P_W is the winding I^2R loss at rated load, W

$$Q_{LOST,O} = \left[\frac{\Theta_{AO,1} - \Theta_{A,1}}{\Theta_{AO,R} - \Theta_{A,R}}\right]^{1/y} P_T \Delta t \tag{G.21}$$

where

P_T is the total losses at rated load, W
$Q_{LOST,O}$ is the heat lost by fluid to ambient, W-min
$\Theta_{A,1}$ is the ambient temperature at the prior time, °C
$\Theta_{A,R}$ is the rated ambient at kVA base for load cycle, °C
$\Theta_{AO,1}$ is the average fluid temperature in tank and radiator at the prior time, °C
$\Theta_{AO,R}$ is the average fluid temperature in tank and radiator at the rated load, °C
Δt is the time increment for calculation, min
y is the exponent of average fluid rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF

To determine the core weight it is necessary to subtract the weight of the windings used in Equation (G.22) from the total core and coil weight given on the outline drawing supplied by the manufacturer.

$$M_W = \frac{M_W Cp_W}{Cp_W} \tag{G.22}$$

where

Cp_W is the specific heat of winding material, W-min/lb °C
$M_W Cp_W$ is the winding mass times specific heat, W-min/°C
M_W is the mass of windings, lb

$$M_{CORE} = M_{CC} - M_W \tag{G.23}$$

where

M_{CC} is the core and coil (untanking) weight, lb
M_{CORE} is the mass of core, lb
M_W is the mass of windings, lb

$$\sum MCp = M_{TANK}\, Cp_{TANK} + M_{CORE}\, Cp_{CORE} + M_{OIL}\, Cp_{OIL} \tag{G.24}$$

where

CP_{CORE}	is the specific heat of the core, W-min/lb °C
CP_{OIL}	is the specific heat of fluid, W-min/lb °C
CP_{TANK}	is the specific heat of the tank, W-min/lb °C
M_{CORE}	is the mass of core, lb
M_{OIL}	is the mass of fluid, lb
M_{TANK}	is the mass of tank, lb
$\sum MCp$	is the total mass times specific heat of oil, tank, and core, W-min/°C

The average oil temperature at time t_2 is given by

$$\Theta_{AO,2} = \frac{Q_{LOST,W} + Q_S + Q_C - Q_{LOST,O} + (\sum MCp)\Theta_{AO,1}}{\sum MCp} \tag{G.25}$$

where

$Q_{LOST,O}$	is the heat lost by fluid to ambient, W-min
$Q_{LOST,W}$	is the heat lost by winding, W-min
Q_C	is the heat generated by core, W-min
Q_S	is the heat generated by stray losses, W-min
ΣMCp	is the total mass times specific heat of fluid, tank, and core, W-min/°C
$\Theta_{AO,1}$	is the average fluid temperature in tank and radiator at the prior time, °C
$\Theta_{AO,2}$	is the average fluid temperature in tank and radiator at the next instant of time, °C

The heat lost by the winding to oil is given by Equation (G.6).

G.3.6 Top and bottom oil temperatures

The top and bottom oil temperatures are determined by an equation similar to the equation for duct oil rise.

$$\Delta\Theta_{T/B} = (\Theta_{TO} - \Theta_{BO}) = \left[\frac{Q_{LOST,O}}{P_T\,\Delta t}\right]^z (\Theta_{TO,R} - \Theta_{BO,R}) \tag{G.26}$$

where

z	is the exponent for top to bottom fluid temperature difference and is 0.5 for ONAN and ONAF; 1.0 for OFAF and ODAF
P_T	is the total losses at rated load, W
$Q_{LOST,O}$	is the heat lost by fluid to ambient, W-min
$\Delta\Theta_{T/B}$	is the temperature rise of oil at top of radiator over bottom fluid, °C
Θ_{BO}	is the bottom fluid temperature, °C
$\Theta_{BO,R}$	is the bottom fluid temperature at rated load, °C
Θ_{TO}	is the top fluid temperature in tank and radiator, °C
$\Theta_{TO,R}$	is the top fluid temperature in tank and radiator at rated load, °C
Δt	is the time increment for calculation, min

The heat lost by the oil, $Q_{LOST,O}$ is given by Equation (G.21). The top and bottom oil temperatures then are determined as follows from Equation (G.2) and Equation (G.3):

$$\Theta_{BO} = \Theta_{AO} - \frac{\Delta\Theta_{T/B}}{2}$$

$$\Theta_{TO} = \Theta_{AO} + \frac{\Delta\Theta_{T/B}}{2}$$

where

Θ_{AO}	is the average fluid temperature in tank and radiator, °C
Θ_{BO}	is the bottom fluid temperature, °C
Θ_{TO}	is the top fluid temperature in tank and radiator, °C
$\Delta\Theta_{T/B}$	is the temperature rise of oil at top of radiator over bottom fluid, °C

G.3.7 Stability requirements

For the ONAN, ONAF, and OFAF cooling modes, the system of equations is stable if the following criteria are met.

$$\frac{\tau_W}{\Delta t} > \left[\frac{\Theta_{W,1} - \Theta_{DAO,1}}{\Theta_{W,R} - \Theta_{DAO,R}}\right]^{1/4} \left[\frac{\mu_{W,R}}{\mu_{W,1}}\right]^{1/4} \tag{G.27A}$$

where

$\Theta_{DAO,1}$	is the average temperature of fluid in cooling ducts at the prior time, °C
$\Theta_{DAO,R}$	is the average temperature of fluid in cooling ducts at rated load, °C
$\Theta_{W,1}$	is the average winding temperature at the prior time, °C
$\Theta_{W,R}$	is the average winding temperature at rated load tested, °C
$\mu_{W,1}$	is the viscosity of fluid for average winding temperature rise at the prior time, cP
$\mu_{W,R}$	is the viscosity of fluid for average winding temperature rise at rated load, cP
τ_W	is the winding time constant, min
Δt	is the time increment for calculation, min

$$\frac{\tau_W}{\Delta t} > \left[\frac{\Theta_{H,1} - \Theta_{WO}}{\Theta_{H,R} - \Theta_{WO,R}}\right]^{1/4} \left[\frac{\mu_{HS,R}}{\mu_{HS,1}}\right]^{1/4} \tag{G.27B}$$

where

$\Theta_{H,1}$	is the winding hottest-spot temperature at the prior time, °C
$\Theta_{H,R}$	is the winding hottest-spot temperature at the rated load, °C
Θ_{WO}	is the temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO,R}$	is the temperature of oil adjacent to winding hot spot at rated load, °C
$\mu_{HS,1}$	is the viscosity of fluid for hot-spot calculation at the prior time, cP
$\mu_{HS,R}$	is the viscosity of fluid for hot-spot calculation at rated load, cP
τ_W	is the winding time constant, min
Δt	is the time increment for calculation, min

and for ODAF

$$\frac{\tau_W}{\Delta t} > 1 \tag{G.27C}$$

where

τ_W	is the winding time constant, min
Δt	is the time increment for calculation, min

For the computer program, a time increment of Δt = 0.5 min is used, and the following criteria used for stability and accuracy for all four cooling modes:

$$\frac{\tau_W}{\Delta t} > 9 \tag{G.27D}$$

If required, the value of Δt is reduced to meet the stability requirement.

G.3.8 Fluid viscosity and specific heats of materials

Fluid viscosity is highly temperature dependant. The fluid viscosity at any temperature is given by an equation of the form

$$\mu = D\,\mathrm{e}^{G/(\Theta + 273)} \tag{G.28}$$

where

D	is a constant (Table G.2)
G	is a constant (Table G.2)
Θ	is the temperature of oil to use for viscosity, °C
μ	is the viscosity of oil, centipoises

The temperatures used to calculate the viscosity are given in Table G.1. Values of the constants D and G for three transformer fluids were derived from property data given in ASTM D3487 [G1], ASTM D4652 [G2], and ASTM D5222 [G3]. The values of these constants are given in Table G.2. Specific heats of materials vary only slightly with temperature so that a constant value may be used. Specific heats are given in Table G.2.

Table G.1—Temperatures for calculating viscosity

Equation number	Viscosity term	Temperature for calculation
G.6A	$\mu_{W,R}$	$(\Theta_{W,R} + \Theta_{DAO,R})/2$
G.6A	$\mu_{W,1}$	$(\Theta_{W,1} + \Theta_{DAO,1})/2$
G.16A	$\mu_{HS,R}$	$(\Theta_{H,R} + \Theta_{WO,R})/2$
G.16A	$\mu_{HS,1}$	$(\Theta_{H,1} + \Theta_{WO,1})/2$

Table G.2—Specific heat and constants for viscosity calculation

Material	Cp[a]	D	G
Oil	13.92	.0013573	2797.3
Silicone	11.49	.12127	1782.3
HTHC	14.55	.00007343	4434.7
Tank(steel)	3.51		
Core(steel)	3.51		
Copper	2.91		
Aluminum	6.80		

[a]W-min./lb °C

G.3.9 Summary of exponents

Values of the exponents used in the temperature calculations are summarized in Table G.3.

The computer program allows changing the *y* exponent for cases for which test data is available.

Table G.3—Summary of exponents

Exponent	Used for	Cooling mode			
		ONAN	ONAF	OFAF	ODAF
x	Duct oil rise	0.5	0.5	0.5	1.0
y	Average oil rise	0.8	0.9	0.9	1.0
z	Top to bottom oil rise in Radiator	0.5	0.5	1.0	1.0

G.3.10 Adjustment of rated test data for a different tap position

If it is desired to adjust the test data for operation on a no-load tap position other than that reported on the test report, Equation (G.29) through Equation (G.31) may be used as follows in G.3.10.1.

G.3.10.1 Top- and bottom-oil rise over ambient

$$\Delta\Theta_{AO,R} = \frac{\Delta\Theta_{TO,R} + \Theta_{BO,R}}{2} \tag{G.29}$$

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at rated load, °C
$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated load, °C

$$\Delta\Theta'_{TO,R} = \Delta\Theta_{AO,R}\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{y} + \left[\frac{\Delta\Theta_{TO,R} - \Delta\Theta_{BO,R}}{2}\right]\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{z} \tag{G.30}$$

where

$P_{T,R}$ is the total losses at rated load, W
$P'_{T,R}$ is the total losses on a different tap, W
y is the exponent of average fluid rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF
z is the exponent for top to bottom fluid temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at rated load, °C
$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated load, °C
$\Delta\Theta'_{TO,R}$ is the top fluid rise over ambient at rated load on a different tap, °C

$$\Delta\Theta'_{BO,R} = \Delta\Theta_{AO,R}\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{y} - \left[\frac{\Delta\Theta_{TO,R} - \Delta\Theta_{BO,R}}{2}\right]\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{z} \tag{G.31}$$

where

$P_{T,R}$	is the total losses at rated load, W
$P'_{T,R}$	is the total losses on a different tap, W
y	is the exponent of average fluid rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF
z	is the exponent for top to bottom fluid temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF
$\Delta\Theta_{AO,R}$	is the average oil rise over ambient at rated load, °C
$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta'_{BO,R}$	is the bottom fluid rise over ambient at rated load on a different tap, °C$\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated load, °C

G.3.10.2 Average winding rise over ambient

For ONAN, ONAF, and ODAF:

$$\Delta\Theta_{DO/BO,R} = \Delta\Theta_{TO,R} - \Delta\Theta_{BO,R} \tag{G.32A}$$

where

$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta_{TO,R}$	is the top fluid rise over ambient at rated load, °C

For OFAF:

$$\Delta\Theta_{DO/BO,R} = \Delta\Theta_{W/A,R} - \Delta\Theta_{BO,R} \tag{G.32B}$$

where

$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta_{W/A,R}$	is the tested or rated average winding rise over ambient, °C

then

$$\Delta\Theta'_{DO/BO,R} = \Delta\Theta_{DO/BO,R}\left[\frac{I'_{R}}{I_{R}}\right]^{2x} \tag{G.33}$$

where

I_R	is the rated current at rated load, A
I'_R	is the rated current at rated load at a different tap position, A
x	is the exponent for duct oil rise over bottom oil, 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta'_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C

For ONAN, ONAF, and OFAF:

$$\Delta\Theta'_{W/A,R} = \left[\Delta\Theta_{W/A,R} - \Delta\Theta_{BO,R} - \frac{\Delta\Theta_{DO/BO,R}}{2}\right]\left[\frac{I'_R}{I_R}\right]^{1.6} + \Delta\Theta'_{BO,R} + \frac{\Delta\Theta'_{DO/BO,R}}{2} \quad \text{(G.34A)}$$

where

I_R	is the rated current at rated load, A
I'_R	is the rated current at rated load at a different tap position, A
$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta'_{BO,R}$	is the bottom fluid rise over ambient at rated load at a different tap position, °C
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta'_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C
$\Delta\Theta_{W/A,R}$	is the tested or rated average winding rise over ambient, °C
$\Delta\Theta'_{W/A,R}$	is the tested or rated average winding rise over ambient at a different tap position, °C

For ODAF:

$$\Delta\Theta'_{W/A,R} = \left[\Delta\Theta_{W/A,R} - \Delta\Theta_{BO,R} - \frac{\Delta\Theta_{DO/BO,R}}{2}\right]\left[\frac{I'_R}{I_R}\right]^{2.0} + \Delta\Theta'_{BO,R} + \frac{\Delta\Theta'_{DO/BO,R}}{2} \quad \text{(G.34B)}$$

where

I_R	is the rated current at rated load, A
I'_R	is the rated current at rated load at a different tap position, A
$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta'_{BO,R}$	is the bottom fluid rise over ambient at rated load at a different tap position, °C
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta'_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C
$\Delta\Theta_{W/A,R}$	is the tested or rated average winding rise over ambient, °C
$\Delta\Theta'_{W/A,R}$	is the tested or rated average winding rise over ambient at a different tap position, °C

G.3.10.3 Hottest-spot rise over ambient

For ONAN, ONAF, and OFAF:

$$\Delta\Theta'_{H/A,R} = \left[\Delta\Theta_{H/A,R} - \Delta\Theta_{BO,R} - \Delta\Theta_{DO/BO,R}\right]\left[\frac{I'_R}{I_R}\right]^{1.6} + \Delta\Theta'_{BO,R} + \Delta\Theta'_{DO/BO,R} \quad \text{(G.35A)}$$

where

I_R	is the rated current at rated load, A
I'_R	is the rated current at rated load at a different tap position, A
$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta'_{BO,R}$	is the bottom fluid rise over ambient at rated load at a different tap position, °C
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta'_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C
$\Delta\Theta_{H/A,R}$	is the winding hottest-spot rise over ambient at rated load, °C
$\Delta\Theta'_{H/A,R}$	is the winding hottest-spot rise over ambient at rated load at a different tap position, °C

For ODAF:

$$\Delta\Theta'_{H/A,R} = \left[\Delta\Theta_{H/A,R} - \Delta\Theta_{BO,R} - \Delta\Theta_{DO/BO,R}\right]\left[\frac{I'_R}{I_R}\right]^{2.0} + \Delta\Theta'_{BO,R} + \Delta\Theta'_{DO/BO,R} \tag{G.35B}$$

where

I_R	is the rated current at rated load
I'_R	is the rated current at rated load at a different tap position
$\Delta\Theta_{BO,R}$	is the bottom fluid rise over ambient at rated load, °C
$\Delta\Theta'_{BO,R}$	is the bottom fluid rise over ambient at rated load at a different tap position, °C
$\Delta\Theta_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C
$\Delta\Theta'_{DO/BO,R}$	is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C
$\Delta\Theta_{H/A,R}$	is the winding hottest-spot rise over ambient at rated load, °C
$\Delta\Theta'_{H/A,R}$	is the winding hottest-spot rise over ambient at rated load at a different tap position, °C

G.3.11 Load cycles and ambient temperatures

Values for the per-unit load and ambient temperature are obtained from a plot or table. In the computer program, the load cycle is described by the end points of straight lines where the load or ambient temperature plot changes slope.

Figure G.1 and the input data file is an example of this concept. This method more accurately describes the variation of load than the step load change or rms method of Clause 7. Values may be input for any number of load points.

G.4 Discussion

The equations require the use of the bottom oil rise over ambient at rated conditions. Reference IEEE Std C57.12.90-1993 [G5] requires that this measurement be made during thermal testing; however, the measurement is not normally reported on the transformer test report. For existing units, the data may be obtained from the manufacturer. Specifications for new transformers should require that both the top and bottom oil temperature rises be stated on the test report.

The exponents in the equations were derived from fluid flow and heat transfer principles. The value of the *y* exponent depends upon the relative contribution of radiation, natural convection, and forced air heat losses and some variation between units. The computer program allows changing the value of the y exponent. Data for the *y* exponent may be obtained from overload heat run in accordance with IEEE Std C57.119 [G6]. It is recommended that no changes be made in the other exponents.

The equations consider a variable ambient during the load cycle. Loading capability as a function of ambient may be determined with the equations. The equation formulation assumes that the temperature of the top oil in the tank and radiators are equal. During cold start-up at temperatures below about –20 °C, the oil in the main tank may become considerable hotter than the oil in the radiator. This depends upon the tank and radiator configuration. This condition is not considered in the equations.

Overexcitation of the core is considered in the program to allow predictions of oil and winding temperatures. Overexcitation may increase core loss several times above rated. Overexcitation above 110% of rated may result in core saturation and excessive local overheating. This is not considered. The loading equations also separate eddy and stray losses from losses due to winding resistance. This will permit a future consideration of oil and winding heating effects due to increased stray and eddy losses when harmonic currents are present. Local overheating due to stray losses in the structural parts or the tank may also occur, and this local overheating is not considered in the loading equations. Other subclauses of the guide should be consulted for other loading limitations.

Thermal testing in accordance with IEEE Std C57.12.90-1993 [G5] is performed by the short-circuit method, which gives zero core loss. The effect of core loss on the oil temperature is determined by holding above rated current. The computer program listed later was developed for loading of in-service transformers with core loss present. To compare the program predictions with the results of overload thermal tests, zero core loss should be used as input and the per-unit loads based on the currents should be held during the various tests.

G.5 Disclaimer statement

This computer program is an essential part of IEEE Std C57.91-2011. This computer program may be copied, sold, or included with software that is sold as long as Annex G of IEEE Std C57.91-2011 is cited as the source. This computer program may be used to implement this standard and may be distributed in source code or compiled form in any manner. This file may be copied for individual use by users who have purchased this standard.

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G.6 Computer program Input data for computer program

Line numbers are used for convenience. They must be used, but have no significance. Reference to instruction numbers refer to the following instructions for data input and default values for unknown data.

	1,
kVA base for losses	____,
Temperature base for losses at this kVA, °C	____,
I^2R losses, P_W, W (see instruction a)	____,
Winding eddy losses, P_E, W (see instruction a)	____,
Stray losses, P_S, W (see instruction a)	____,
Core loss, $P_{C,R,}$,W	____,

	2,
One per unit kVA base for load cycle	____,
Data at this kVA (temperatures and temperature rises in °C):	
Rated average winding rise over ambient	____,
Tested or rated average winding rise over ambient, $\Delta\Theta_{W/A,R}$	____,
Tested or rated hot-spot rise over ambient, $\Delta\Theta_{H/A,R}$	____,
Tested or rated top-oil rise over ambient, $\Delta\Theta_{TO,R}$	____,
Tested or rated bottom oil rise over ambient, $\Delta\Theta_{BO,R}$	____,
Rated ambient temperature, $\Theta_{A,R}$	____,

3,

Winding conductor, 1 = aluminum, 2 = copper ____,

Per unit eddy loss at winding hot-spot, E_{HS} (see instruction b) ____,

Winding time constant, τ_W, minutes (See instruction c) ____,

Per unit winding height to hot spot, H_{HS} (see instruction d) ____,

4,

Weight of core and coils, M_{CC}, lb ____,

Weight of tank and fittings, M_{TANK}, lb ____,

Type fluid, 1 =oil, 2=silicone, 3=HTHC ____,

Gallons of fluid ____,

(See instruction e) 5,

Over excitation occurs, 0 = no, 1 = yes ____,

Time when over excitation occurs, h ____,

Core loss during overexcitation, $P_{C,OE}$, W ____,

6,

Loading case, 1 or 2 ____

For case 1 the loading cycle (usually 24 h)

is assumed to repeat and the initial temperatures are not known.

For case 2, the initial temperatures (see instruction f) are input at line 7.

NOTE — Line 7 data must be input for case 2 and must not be input for case 1.

7,

(See instruction f)

Initial winding hottest-spot temperature, Θ_{HS}, °C ____,

initial average winding temperature, Θ_W, °C ____,

Initial top-oil temperature, Θ_{TO},°C ____,

Initial top-duct-oil temperature, Θ_{TDO}, °C ____,

Initial bottom-oil temperature, Θ_{BO}, °C ____,

8,

Type cooling for load cycle, 1 = ONAN, 2 = ONAF, 3 = non-directed OFAF, 4 = directed ODAF ____,

Print temperature table, 0=no, 1=yes ____,

Time increment for printing, minutes ____,

Number of points on load cycle ____,

Data for load cycle, time in hours, ambient in °C (see instruction g):

10,time(1),ambient(1),per-unit load(1)
11,time(2),ambient(2),per-unit load(2)
12,time(3),ambient(3),per-unit load(3)…

xx,time (last),ambient (last),per-unit load (last)

The following are instructions for data input and default values for unknown data:

a) Stray losses and winding eddy losses vary inversely with temperature. The total stray and eddy loss may be obtained by calculating total I^2R using the resistance data from the total load loss. The computer program calculates a ratio of instantaneous losses to rated losses to determine the various temperature components. Since stray and eddy losses vary inversely with temperature, it is conservative to assume zero winding eddy loss, that is, the ratio is higher when zero eddy losses are assumed. If resistance data is not available or if a calculation of I^2R is not made, it is conservative to input total load losses for I^2R loss and zero values for winding eddy loss and stray loss.

b) If the per unit eddy loss at the winding hot-spot location is unknown, use zero. This gives conservative results for the reasons given in instruction a).

c) Typical values of the winding time constant are 3–7 min. Estimates may be obtained from resistance cooling curve data from thermal testing. Overloads greater than 1/2 h have a minor effect on the hottest-spot temperature calculation. If the time constant is unknown, 5 min is suggested.

d) If the location of the winding hottest spot is unknown, input 1.00 for per unit winding height to the hottest-spot location. Values less than 1.00 are used to compare predicted hot spot temperatures with tested values in test windings with imbedded thermocouples or transformers with fiber optic hotspot detectors.

e) If overexcitation does not occur, input zero for time overexcitation and normal excitation core loss for core loss during overexcitation.

f) Case 1 is used for repeating load cycles (usually 24 h) such as planned overloading. Case 2 is used for short-time loading or emergency load cycles that do not repeat and may last less than 24 h. For case 2, the initial temperatures are determined by running a case 1 analysis and using the final temperatures as initial temperatures in line 7 for a case 2 analysis. For convenience, the computer program output lists final temperatures in the same order needed for input in line 7.

g) For repeating load cycles, data statements for 0 h and the last time input are equal unless a step load change occurs at zero time. Step changes in load are illustrated by the following example. Assume that the load increases from 0.7 to 1.5 at time 1 h with the ambient of some value, say 30 °C. Two sequential lines of data for the one hour point are required as follows:
   xx1.0,30.0,70
   xx,l.0,30.0,1.5

Program example:

It is desired to evaluate the load capability of a transformer rated ONAN/ONAF/ONAF-T-60-28000/37333/46667/52267-138000-34500Y/19919 for a summer load cycle with a maximum ambient of 40 °C and a peak load of 1.1. The losses on the test report are given at 28 000 kVA and 75 °C as follows:

No load	36 986 W
Load loss	72 768 W
Total loss	109 755 W

From the resistance data the I^2R losses are calculated to be 51 690 W. Thus, total stray and eddy loss is 72 768–51 690 or 21 078 W. The temperature rise data at 52 267 kVA and the weights and fluid quantity are given as follows.

Core and coil weight, lb	75,600
Tank and radiators, lb	31,400
Gallons of oil	4,910
Temperature rises at 52,267 kVA, °C:	
Average wdg. guar.	65
Average wdg. test	63
Hottest spot	80
Top oil	55
Bottom oil	25

Values for the per-unit load and ambient are obtained from a plot of the load cycle. Values may be input for any number of load points. A plot of the load cycle is shown in Figure G.1.

PU LOAD

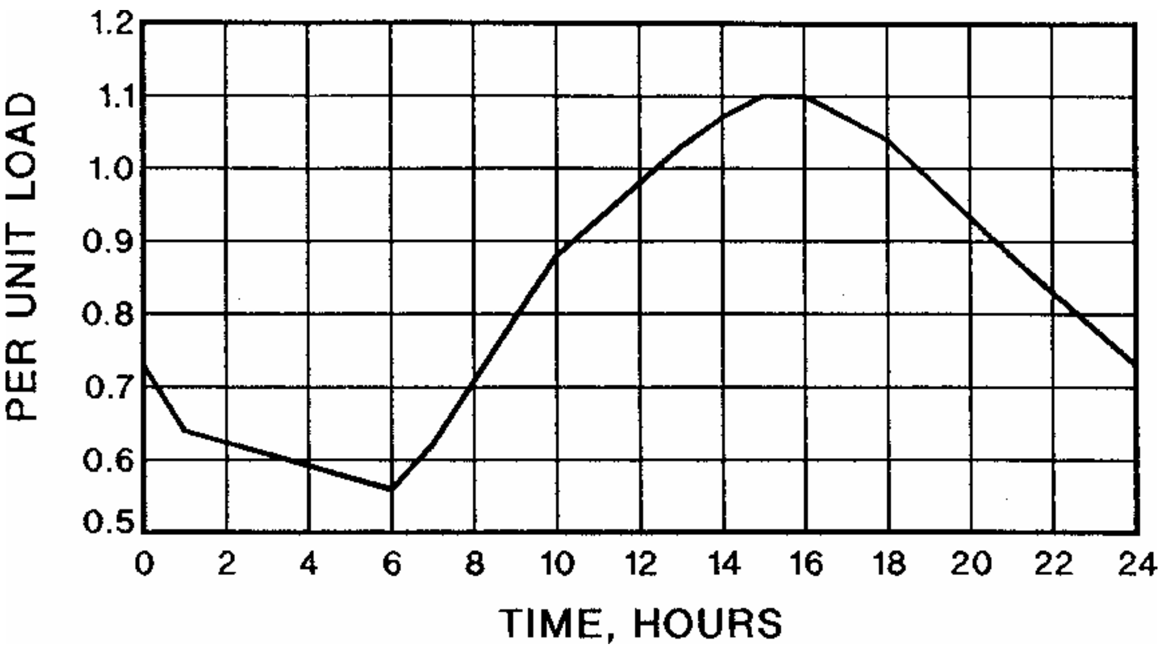

Figure G.1—Example load cycle

The input data file is shown below. The program output file is printed on the following pages.

Input data file:

```
1,28000,75.,51690,0,21078,36986
2,52267,65,63.0,80,55.0,25.0,30.0
3,2,0,5,1.00
4,75600,31400,1,4910
5,0,0,36986
6,1
9,2,1,60,12
10,0,30.0, .73
11,1,29.5, .64
```

12,6,28.2, .56
13,7,29.8, .62
14,10,35.9, .88
15,13,39.6,1.03
16,14,40,1.07
17,15,40,1.10
18, 16,39.6,1.10
19,18,36.8,1.04
20,21,32.5, .88
21,24,30.0, .73

Output data file from program:

PROGRAM LOADT, VERSION 1.1, 9-15-1993

TRANSFORMER TEMPERATURE CALCULATION WITH VARIABLE LOAD AND AMBIENT TEMPERATURE USING BOTTOM OIL RISE DUCT OIL RISE, RESISTANCE CHANGE WITH TEMPERATURE CORRECTIONS FOR FLUID VISCOSITY FOR ONAN, ONAF, AND NON-DIRECTED OFAF COOLING MODES. NO VISCOSITY CORRECTION FOR DIRECTED ODAF COOLING MODE.

INPUT DATA FILENAME IS LCYC
OUTPUT DATA FILENAME IS LCYCOUT

KVA BASE FOR LOSS INPUT DATA	= 28000
TEMPERATURE BASE FOR LOSS INPUT DATA	= 75 C
WINDING I SQUARE R	= 51690 WATTS
WINDING EDDY LOSS	= 0 WATTS
STRAY LOSSES	= 21078 WATTS
CORE LOSS	= 36986 WATTS
TOTAL LOSSES	= 109754 WATTS

WINDING CONDUCTOR IS COPPER

PER UNIT EDDY LOSS AT HOT SPOT LOCATION	= 0
WINDING TIME CONSTANT	= 5 MINUTES
PER UNIT WINDING HEIGHT TO HOT SPOT	= 1

WEIGHT OF CORE & COILS	= 75600 POUNDS
WEIGHT OF TANK AND FITTINGS	= 31400 POUNDS
GALLONS OF FLUID	= 4910

COOLING FLUID IS TRANSFORMER OIL

ONE PER UNIT LOAD. = 52267 KVA
FORCED AIR (ONAF) COOLING
EXPONENT OF LOSSES FOR AVERAGE FLUID RISE = 0.9
AT THIS KVA LOSSES AT 95 C ARE AS FOLLOWS:

WINDING I SQUARE R	= 191752.2 WATTS
WINDING EDDY LOSS	= 0 WATTS
STRAY LOSSES	= 68988.03 WATTS
CORE LOSSES	= 36986 WATTS
TOTAL LOSS	= 297726.3 WATTS

AT THIS KVA INPUT DATA FOR TEMPERATURES AS FOLLOWS:

RATED AVERAGE WINDING RISE OVER AMBIENT	= 65 °C
TESTED AVERAGE WINDING RISE OVER AMBIENT	= 63 °C
HOTTEST SPOT RISE OVER AMBIENT	= 80 °C

TOP FLUID RISE OVER AMBIENT = 55 °C
BOTTOM FLUID RISE OVER AMBIENT = 25 °C
RATED AMBIENT TEMPERATURE = 30 °C

CORE OVEREXCITATION DOES NOT OCCUR

(LOAD-TEMPERATURE TABLE ON PAGE TWO)

Load temperature table

Time Hours	PU Load	AMB Temp	HS Temp	TOPO Temp	TOPDO Temp	BOTO Temp
0.000	0.730	30.0	89.9	74.1	69.6	48.0
1.000	0.640	29.5	82.7	69.5	64.0	45.0
2.000	0.624	29.2	77.9	65.4	60.5	42.4
3.000	0.608	29.0	74.5	62.5	58.1	40.6
4.000	0.592	28.7	71.9	60.3	56.2	39.3
5.000	0.576	28.5	69.7	58.6	54.6	38.2
6.000	0.560	28.2	67.8	57.2	53.2	37.3
7.000	0.620	29.8	68.7	56.6	54.9	37.7
8.000	0.707	31.8	73.7	58.5	59.3	39.7
9.000	0.793	33.9	82.4	62.7	65.2	42.9
10.000	0.880	35.9	92.3	68.5	72.2	47.1
11.000	0.930	37.1	100.4	74.9	78.4	51.3
12.000	0.980	38.4	108.0	80.9	84.3	55.4
13.000	1.030	39.6	115.7	86.6	90.1	59.5
14.000	1.070	40.0	122.3	92.0	95.3	63.1
15.000	1.100	40.0	127.7	96.6	99.5	66.1
16.000	1.100	39.6	130.0	99.8	101.7	68.0
17.000	1.070	38.2	128.4	100.8	101.1	68.2
18.000	1.040	36.8	125.7	99.6	98.9	66.9
19.000	0.987	35.4	121.0	96.7	94.8	64.6
20.000	0.933	33.9	115.1	92.6	89.8	61.3
21.000	0.880	32.5	108.6	87.9	84.4	57.7
22.000	0.830	31.7	102.1	83.0	79.2	54.3
23.000	0.780	30.8	95.9	78.4	74.3	51.1
24.000	0.730	30.0	89.9	74.1	69.6	48.0

TEMPERATURES DURING LOAD CYCLE:
MAX. HOT SPOT TEMP. = 130.0855 AT 16.08333 HOURS
MAX. TOP FLUID TEMP. = 100.7999 AT 16.85 HOURS

FINAL HOT SPOT TEMP. = 89.9446
FINAL AVE. WIND. TEMP. = 73.36386
FINAL TOP OIL TEMP. = 74.08505
FINAL DUCT OIL TEMP. = 69.60123
FINAL BOT. OIL TEMP. = 48.01001

EQUIVALENT AGING = 36.22312 HOURS
LOAD CYCLE DURATION = 24 HOURS
EQUIVALENT AGING FACTOR = 1.509297 PER UNIT

Program listing:

```
10    REM PROGRAM LOADT,9-15-1993
20    DEFINT I-N:DIM TIM(100),PUL(100),AMB(100),TIMP(1500)
30    PRINT “ENTER INPUT DATA FILENAME”
40    INPUT F2$
50    PRINT “ENTER OUTPUT FILENAME”
60    INPUT F1$
70    OPEN F2$ FOR INPUT AS #2
80    OPEN F1$ FOR OUTPUT AS #1
90    INPUT #2, LN,XKVA1,TKVA1,PW,PE,PS,PC
100   INPUT #2, LN, XKVA2,THKVA2,THEWA,THEHSA,THETOR,THEBOR,TAR
110   INPUT #2, LN,MC,PUELHS,TAUW,HHS
120   INPUT #2, LN,WCC,WTANK,MF,GFLUID
130   INPUT #2, LN,MCORE,TIMCOR,PCOE
140   INPUT #2, LN, LCAS
150   ON LCAS GOTO 170,160
160   INPUT #2, LN, THS,TW,TTO,TTDO,TBO
170   INPUT #2, LN,MA,MPR1,DTP,JJ
180   FOR J=l TO JJ
190   INPUT #2, LN,TIM(J),AMB(J),PUL(J)
200   TIM(J)=60!*TIM(J)
210   NEXT J
220   CLOSE #2
230   PT=PW+PE+PS+PC
240   PRINT #1, “PROGRAM LOADT, VERSION 1.1, 9-15-1993”
250   PRINT #1,“TRANSFORMER TEMPERATURE CALCULATION WITH VARIABLE”
260   PRINT #1,“LOAD AND AMBIENT TEMPERATURE USING BOTTOM OIL RISE”
270   PRINT #1,“DUCT OIL RISE, RESISTANCE CHANGE WITH TEMPERATURE”
280   PRINT #1,“CORRECTIONS FOR FLUID VISCOSITY FOR ONAN, ONAF, AND NON-”
290   PRINT #1,“DIRECTED OFAF COOLING MODES. NO VISCOSITY CORRECTION”
300   PRINT #1,“FOR DIRECTED ODAF COOLING MODE.”
310   PRINT #1,
320   PRINT #1,“INPUT DATA FILENAME IS ”;F2$
330   PRINT #1,“OUTPUT DATA FILENAME IS ”;F1$
340   PRINT #1,
350   PRINT #1,“KVA BASE FOR LOSS INPUT DATA = ”;XKVA1
360   PRINT #1,“TEMPERATURE BASE FOR LOSS INPUT DATA = ”;TKVA1;“C”
370   PRINT #1,“WINDING I SQUARE R = “;PW;“WATTS”
380   PRINT #1,“WINDING EDDY LOSS = ”;PE;“WATTS”
390   PRINT #1,“STRAY LOSSES = ”;PS;“WATTS”
400   PRINT #1,“CORE LOSS = ”;PC;“WATTS”
410   PRINT #1,“TOTAL LOSSES = ”;PT;“WATTS”
420   PRINT #1,
430   ON MC GOTO 440,460
440   PRINT #1,“WINDING CONDUCTOR IS ALUMINUM”
450   TK=225!:CPW=6.798:GOTO 480
460   PRINT #1,“WINDING CONDUCTOR IS COPPER”
470   TK=234.5:CPW=2.91
480   PRINT #1,“PER UNIT EDDY LOSS AT HOT SPOT LOCATION = ”;PUELHS
490   PRINT #1,“WINDING TIME CONSTANT = ”;TAUW;“MINUTES”
500   PRINT #1,“PER UNIT WINDING HEIGHT TO HOT SPOT = ”;HHS
510   PRINT #1,
520   PRINT #1,“WEIGHT OF CORE & COILS = ”;WCC;“POUNDS”
530   PRINT #1,“WEIGHT OF TANK AND FITTINGS = ”;WTANK;“POUNDS”
540   PRINT #1,“GALLONS OF FLUID = ”;GFLUID
550   ON MF GOTO 560,580,600
560   CPF=13.92:RHOF=.031621:C=2797.3:B=.0013473
570   PRINT #1, “COOLING FLUID IS TRANSFORMER OIL”:GOTO 620
580   CPF=11.49:RHOF=.0347:C=1782.3:B=.12127
```

```
590   PRINT #1, “COOLING FLUID IS SILICONE”:GOTO 620
600   CPF=14.55:RHOF=.03178:C=4434.7:B=7.343E-05
610   PRINT #1, “COOLING FLUID IS HTHC”
620   PRINT #1,
630   PRINT #1,“ONE PER UNIT LOAD. = ”;XKVA2;“ KVA”
640   ON MA GOTO 650,680,710,740
650   X=.5:YN=.8:Z=.5:THEDOR=THETOR
660   PRINT “COOLING MODE IS ONAN”
670   PRINT #1, “COOLING MODE IS ONAN”:GOTO 770
680   X=.5:YN=. 9:Z=.5:THEDOR=THETOR
690   PRINT “COOLING MODE IS ONAF”
700   PRINT #1, “FORCED AIR (ONAF) COOLING”:GOTO 770
710   X=.5:YN=.9:Z=1!:THEDOR=THEWA
720   PRINT “COOLING MODE IS NON-DIRECTED OFAF”
730   PRINT #1, “NON-DIRECTED FORCED OIL (OFAF) COOLING”:GOTO 770
740   X=1! :YN=1! :Z=1! :THEDOR=THETOR
750   PRINT “COOLING MODE IS DIRECTED ODAF”
760   PRINT #1, “DIRECTED FORCED OIL COOLING (ODAF)”
770   PRINT “NOMINAL VALUE OF Y EXPONENT IS”;YN
780   PRINT “DO YOU WISH TO CHANGE? TYPE Y FOR YES OR N FOR NO”
790   INPUT F3$
800   IF F3$ = “Y” THEN GOTO 820
810   GOTO 840
820   PRINT “INPUT DESIRED VALUE OF Y EXPONENT”
830   INPUT YN
840   PRINT “PROGRAM IS RUNNING”
850   PRINT #1, “EXPONENT OF LOSSES FOR AVERAGE FLUID RISE = ”;YN
860   TWR=TAR+THKVA2 :TWRT=TAR+THEWA
870   THSR=TAR+THEHSA:TTOR=TAR+THETOR
880   TBOR=TAR+THEBOR: TTDOR=THEDOR+TAR
890   TWOR=(HHS* (TTDOR-TBOR) )+TBOR
900   TDAOR=(TTDOR+TBOR) /2! :TFAVER=(TTOR+TBOR) /2!
910   XK2=(XKVA2/XKVA1)^2! :TK2=(TK+TWR)/(TK+TKVA1)
920   PW=XK2*PW*TK2:PE=XK2*PE/TK2:PS=XK2*PS/TK2
930   PT=PW+PE+PS+PC
940   IF (PE/PW)>PUELHS THEN PUELHS=PE/PW
950   TKHS=(THSR+TK) / (TWR+TK) :PWHS=TKHS*PW
960   PEHS=PUELHS* PWHS
970   PRINT #1, “AT THIS KVA LOSSES AT”;TWR;”C ARE AS FOLLOWS:”
980   PRINT #1,“WINDING I SQUARE R = ”;PW;“WATTS”
990   PRINT #1,“WINDING EDDY LOSS = ”;PE;“WATTS”
1000  PRINT #1,“STRAY LOSSES = ”;PS;“WATTS”
1010  PRINT #1,“CORE LOSSES = ”;PC;“WATTS”
1020  PRINT #1,“TOTAL LOSS = ”;PT;“WATTS”:PRINT #1,
1030  PRINT #1,“AT THIS KVA INPUT DATA FOR TEMPERATURES AS FOLLOWS:
1040  PRINT #1,“RATED AVERAGE WINDING RISE OVER AMBIENT = ”;THKVA2;“C”
1050  PRINT #1,“TESTED AVERAGE WINDING RISE OVER AMBIENT = ”;THEWA;“C”
1060  PRINT #1,“HOTTEST SPOT RISE OVER AMBIENT = ”;THEHSA;“C”
1070  PRINT #1,“TOP FLUID RISE OVER AMBIENT = ”;THETOR;“C”
1080  PRINT #1,“BOTTOM FLUID RISE OVER AMBIENT = ”;THEBOR;“C”
1090  PRINT #1,“RATED AMBIENT TEMPERATURE = ”;TAR;“C”
1100  IF MCORE<1 GOTO 1140
1110  PRINT #1,“CORE OVEREXCITATION OCCURS AT ”;TIMCOR;“HOURS”
1120  PRINT #1,“CORE OVEREXCITATION LOSS IS ”;PCOE;“WATTS”
1130  GOTO 1150
1140  PRINT #1,“CORE OVEREXCITATION DOES NOT OCCUR”
1150  IF MPR1<1 GOTO 1230
1160  PRINT #1,
1170  PRINT #1, “(LOAD-TEMPERATURE TABLE ON PAGE TWO)”
```

```
1180  FOR I=l TO 15
1190  PRINT #1,
1200  NEXT I
1210  PRINT #1, “LOAD TEMPERATURE TABLE”
1220  PRINT #1,
1230  TIMCOR=60*TIMCOR
1240  DT=. 5
1250  IF (TAUW/DT)>9! THEN GOTO 1270
1260  DT=DT/2!:GOTO 1250
1270  XMCP=(PE+PW)*TAUW/(TWRT-TDAOR) :WWIND=XMCP/CPW
1280  IF WWIND>WCC THEN GOTO 2260
1290  WCORE=WCC-WWIND:CPST=3.51:WFL=GFLUID*231*RHOF
1300  SUMMCP=(WTANK*CPST)+(WCORE*CPST)+(WFL*CPF)
1310  DEF FNV(B,C,TMU)=B*EXP(C/(TMU+273!))
1320  T=(TWRT+TDAOR)/2! :VISR=FNV(B,C,T)
1330  T= (THSR+TWOR) /2! :VIHSR=FNV(B, C, T)
1340  TMP=0!:IF MPR1<1 THEN DTP=15
1350  KK=INT((TIM(JJ)/DTP)+.01)
1360  FOR K=1 TO KK
1370  TMP=TMP+DTP:TIMP(K) =TMP
1380  NEXT K
1390  PRINT #1,
1400  C$=“##.###     ##.###     ##.#     ###.#     ###.#     ###.#     ###.#”
1410  IF MPR1<1 THEN GOTO 1450
1420  PRINT #1, “ TIME      PU      AMB      HS      TOPO      TOPDO      BOTO”
1430  PRINT #1, “HOURS     LOAD      TEMP      TEMP      TEMP      TEMP      TEMP”
1440  PRINT #1,
1450  ON LCAS GOTO 1460,1480
1460  THS=THSR:TW=TWRT:TTO=TTOR:TTDO=TTDOR:TBO=TBOR
1470  PR =0:JLAST=2:GOTO 1490
1480  MPR=MPR1 : JLAST=1
1490  TFAVE= (TTO+TBO)/2! :TWO=TBO+ (HHS* (TTDO-TBO))
1500  FOR JJJ=1 TO JLAST
1510  IF JJJ=2 THEN MPR=MPR1
1520  THSMAX=THS :TIMHS=0 :TTOMAX=TTO :TIMTO=0
1530  J=1:K=1:TIMS=0! :TIMSH=0! :ASUM=0!
1540  IF MPR<1 THEN GOTO 1560
1550  PRINT #1, USING C$;TIMSH, PUL(1),AMB(1),THS,TTO,TTDO,TBO
1560  TIMS=TIMS+DT
1570  IF TIMS>TIM(J+1) THEN J=J+l
1580  IF TIMS>TIM(JJ) THEN GOTO 2120
1590  TIMSH=TIMS/60!
1600  IF ABS (TIM(J+l)-TIM(J))<.01 THEN J=J+l
1610  SL=(PUL(J+1)-PUL(J))/(TIM(J+1)-TIM(J))
1620  PL=PUL(J)+(SL*(TIMS-TIM(J)) )
1630  SLAMB=(AMB(J+1)-AMB(J))/(TIM(J+1)-TIM(J))
1640  TA=AMB(J)+(SLAMB*(TIMS-TIM(J)))
1650  TDAO=(TTDO+TBO)/2!
1660  TKW= (TW+TK)/(TWR+TK)
1670  QWGEN=PL*PL*((TKW*PW)+(PE/TKW))*DT
1680  IF TW<TDAO THEN GOTO 1750
1690  ON MA GOTO 1700,1700,1700,1730
1700  T=(TW+TDAO)/2! :VIS=FNV(B,C,T)
1710  QWLOST=(((TW-TDAO)/(TWRT-TDAOR))^1.25)*((VISR/VIS)^.25)*(PW+PE)*DT
1720  GOTO 1770
1730  QWLOST=((TW-TDAO)/(TWRT-TDAOR))*(PW+PE)*DT
1740  GOTO 1770
1750  QWLOST=0!
1760  IF TW<TBO THEN TW=TBO
```

```
1770  TW= (QWGEN-QWLOST+(XMCP*TW))/XMCP
1780  DTDO=(TTDOR-TBOR)* ((QWLOST/((PW+PE)*DT) )^X)
1790  TTDO=TBO+DTDO:TDAO=(TTDO+TBO)/2!
1800  TWO=TBO+(HHS*DTDO) :TKHS=(THS+TK)/(THSR+TK)
1810  IF (TTDO+.1)<TTO THEN TWO=TTO
1820  IF THS<TW THEN THS=TW
1830  IF THS<TWO THEN THS=TWO
1840  QHSGEN=PL*PL*((TKHS*PWHS)+(PEHS/TKHS))*DT
1850  ON MA GOTO 1860,1860,1860,1890
1860  T=(THS+TWO)/2! :VISHS=FNV(B,C,T)
1870  QLHS=(((THS-TWO)/(THSR-TWOR))^1.25)*((VIHSR/VISHS)^.25)*(PWHS+PEHS)*DT
1880  GOTO 1900
1890  QLHS=((THS-TWO)/(THSR-TWOR))*(PWHS+PEHS)*DT
1900  THS= (QHSGEN-QLHS+(XMCP*THS))/XMCP
1910  QS=((PL*PL*PS)/TKW)*DT
1920  QLOSTF=(((TFAVE-TA)/(TFAVER-TAR))^(1/YN))*PT*DT
1930  IF MCORE<1 THEN GOTO 1960
1940  IF TIMS<TIMCOR THEN GOTO 1960
1950  QC=PCOE*DT: GOTO 1970
1960  QC=PC*DT
1970  TFAVE=(QWLOST+QC+QS-QLOSTF+(SUMMCP*TFAVE))/SUMMCP
1980  DTTB=((QLOSTF/(PT*DT))^Z)*(TTOR-TBOR)
1990  TTO=TFAVE+(DTTB/2!) :TBO=TFAVE-(DTTB/2!)
2000  IF TBO<TA THEN TBO=TA
2010  IF TTDO<TBO THEN TTDO=TBO
2020  AX=(15000!/383!)-(15000!/(THS+273!))
2030  A=EXP(AX) :ASUM=ASUM+(A*DT)
2040  IF THS<THSMAX THEN GOTO 2060
2050  THSMAX=THS:TIMHS=TIMSH
2060  IF TTO<TTOMAX THEN GOTO 2080
2070  TTOMAX=TTO: TIMTO=TIMSH
2080  IF TIMS<TIMP(K) THEN GOTO 1560
2090  IF MPR<1 THEN GOTO 2110
2100  PRINT #1, USING C$; TIMSH, PL, TA, THS, TTO, TTDO, TBO
2110  K=K+1: GOTO 1560
2120  NEXT JJJ
2130  TIMS=TIMS-DT: ASUM=ASUM/60! : AEQ=ASUM/TIMSH: PRINT #1,
2140  PRINT #I,“TEMPERATURES DURING LOAD CYCLE:”
2150  PRINT #1, “MAX. HOT SPOT TEMP. =”; THSMAX; “AT”; TIMHS; “HOURS”
2160  PRINT #1, “MAX. TOP FLUID TEMP. =”; TTOMAX; “AT”; TIMTO; “HOURS”
2170  PRINT #1, PRINT #1, “FINAL HOT SPOT TEMP. =”; THS
2180  PRINT #1, “FINAL AVE. WIND. TEMP. =”; TW
2190  PRINT #1, “FINAL TOP OIL TEMP. =”; TTO
2200  PRINT #1, “FINAL DUCT OIL TEMP. =”; TTDO
2210  PRINT #1, “FINAL BOT. OIL TEMP. =”; TBO: PRINT #1,
2220  PRINT #1, “EQUIVALENT AGING =”; ASUM; “HOURS”
2230  PRINT #1, “LOAD CYCLE DURATION =”; TIMSH; “HOURS”
2240  PRINT #1, “EQUIVALENT AGING FACTOR =”; AEQ; “PER UNIT”
2250  GOTO 2290
2260  PRINT “WINDING TIME CONSTANT TOO HIGH”
2270  PRINT #1, “CHANGE INPUT TO LOWER VALUE”
2280  PRINT “CHANGE INPUT TO LOWER VALUE IN INPUT FILE”; F2$
2290  CLOSE #1
2300  END
```

G.7 Bibliography for Annex G

[G1] ASTM D3487, *Standard Specification for Mineral Oil in Electrical Apparatus*.

[G2] ASTM D4652, *Standard Specification for Silicone Fluid Used for Electrical Insulation*.

[G3] ASTM D5222), *Standard Specification for High Fire-Point Mineral Electrical Insulating Oils*.

[G4] Aubin, J., and Langhame, T., *Effect of Oil Viscosity on Transformer Loading Capability at Low Ambient Temperatures*, IEEE Transactions on Power Delivery, vol. 7, no. 2, pp. 516–524, April 1992.

[G5] IEEE Std C57.12.90-1993, *IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers.*

[G6] IEEE Std C57.11-2001, IEEE Recommended Practice for Performing Temperature Rise Tests on Oil-Immersed Power Transformers at Loads Beyond Nameplate Rating.

[G7] Pierce, L. W., *An Investigation of the Thermal Performance of an Oil Filled Transformer Winding*, IEEE Transactions on Power Delivery, vol. 7, no. 3, pp. 1347–1358, July 1992.

[G8] Pierce, L. W., *Predicting Liquid Filled Transformer Loading Capability*, IEEE Transactions on Industry Applications, vol. 30, no. 1, pp. 170–178, Jan./Feb. 1994.

Annex H

(normative)

Operation with part or all of the cooling out of service

H.1 General

Where auxiliary equipment, such as pumps or fans, or both, is used to increase the cooling efficiency, the transformer may be required to operate for some time without this equipment functioning. The permissible loading under such conditions is given in the following clauses.

H.2 ONAN/ONAF transformers

Some manufactures use a large number of small fans and others use a small number of large fans. If the number of fans inoperative is a large percentage of the total, use the self-cooled (ONAN) rating. For some designs only one or two inoperative fans may result in loss of significant cooling capacity.

H.3 ONAN/ONAF/ONAF, ONAN/ONAF/OFAF, and ONAN/OFAF/OFAF transformers

For triple rated forced-air, forced-oil-cooled transformers with all or part of the cooling inoperative use the nameplate rating based on the full stage of cooling remaining in operation, or if less than a full stage of fan and pump cooling is operative, use the self-cooled (ONAN) rating. For loss of either fans or pumps on a stage of cooling, use the rating that pertains to total loss of that stage of cooling. For large units with a large number of fans, the loss of one or two fans will result in minimal temperature increase. For non-directed OFAF units, the loss of one or more pumps with the fans still in operation results in an increase in tank top oil, which gives increased temperatures for bushings, cables, and other ancillary components; however, the increase in winding hot-spot rise may not be significant.

H.4 OFAF and OFWF transformers

H.4.1 General

In general, the heat exchangers used to cool OFAF and OFWF type transformers will dissipate only an insignificant amount of heat when either the forced-oil circulation or the forced cooling medium (air or water) are inoperative. If only part of the coolers is inoperative, then refer to H.5 for load capability. If all of the coolers are inoperative, loading amounts and durations can be calculated as in H.4.2.

The amount of load carried, the duration of the load, the previous loading condition, the ambient temperature, and the physical parameters of the transformer determine its hottest-spot temperature and the loss-of-life experienced during the period of loss of all cooling. The user should calculate in accordance with the method below and refer to other pertinent clauses of this guide to determine the effects of the operating condition. During the period of loss of all cooling, the only significant amount of heat dissipated by the transformer will depend on tank radiation and its convection characteristics, which, in turn, are dependent on tank dimensions. Heat dissipation characteristics may be calculated from measurements obtained by measuring the actual unit or from estimations based on the transformer outline drawings.

H.4.2 Calculations

An approximation of the effect of loading and time upon the oil and hottest-spot temperature can be determined as shown in this clause. More accurate data may be obtained from the manufacturer.

H.4.2.1 Equations

1) Estimate the losses in watts that will be dissipated by the tank at the 100% OFAF oil rise after loss of all cooling as follows:

$$q_{TANK} = (0.00365)(0.155 \times S)(\Delta\Theta_{AO,R})^{1.21} \tag{H.1}$$

where

q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$, W
S is the sum of surface areas of tank walls and cover neglecting braces, appurtenances, etc., cm^2
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C

2) Estimate the ultimate rise of average oil for the load that is to be maintained as follows:

$$\Delta\Theta_{AO,U} = \left(\frac{P_T}{q_{TANK}}\right)^{0.8} \Delta\Theta_{AO,R} \tag{H.2}$$

where

P_T is the total losses in watts, at load to be maintained
q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$, W
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{AO,U}$ is the ultimate rise of average oil over ambient, °C

3) The time constant corresponding to this loading condition should be calculated as follows:

$$\tau_L = \frac{C\left[\Delta\Theta_{AO,U} - \Delta\Theta_{AO,R}\right]}{P_T - q_{TANK}} \tag{H.3}$$

where

C is the thermal capacity as defined in Equation (13A) or Equation (13B)
P_T is the total losses in watts, at load to be maintained
q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$
$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{AO,U}$ is the ultimate rise of average oil over ambient, °C
τ_L is the oil time constant corresponding to loading condition, h

4) The average oil rise at any time t for the transformer in this operating mode can be estimated from the following formula:

$$\Delta\Theta_{AO} = \left(\Delta\Theta_{AO,U} - \Delta\Theta_{AO,R}\right)\left(1 - e^{\frac{-t}{\tau_L}}\right) + \Delta\Theta_{AO,R} \tag{H.4}$$

where

t	is the time, h
$\Delta\Theta_{AO}$	is the average oil rise over ambient at time t, °C
$\Delta\Theta_{AO,R}$	is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{AO,U}$	is the ultimate rise of average oil over ambient, °C
τ_L	is the oil time constant corresponding to loading condition, h

5) During the time period of t/τ_L = 0 to 0.15, the difference between top-oil temperature and average oil temperature can be estimated as follows:

$$\Delta\Theta_{TO-AO} = 7t + 6 \tag{H.5}$$

where

t	is the time, h
$\Delta\Theta_{TO\text{-}AO}$	is the difference in top oil temperature and average oil temperature, °C

The estimated top-oil rise can then be determined as follows:

$$\Delta\Theta_{TO} = \Delta\Theta_{TO-AO} + \Delta\Theta_{AO} \tag{H.6}$$

where

$\Delta\Theta_{AO}$	is the average oil rise over ambient at time t, °C
$\Delta\Theta_{TO}$	is the top-oil temperature rise over ambient, °C
$\Delta\Theta_{TO\text{-}AO}$	is the difference in top oil temperature and average oil temperature, °C

It is recommended that $\Delta\Theta_{TO} + \Theta_A$ not exceed 110 °C.

Estimates of top-oil rises at t/τ_L greater than 0.15 will have to be obtained from the manufacturer.

The hottest-spot rise above top-oil temperature, for directed oil flow units, will increase substantially when the forced-oil flow is stopped. An estimate of this rise can be obtained from the manufacturer. On the premise that some reasonable oil circulation will continue by natural convection, a rough estimate can be made as shown in the paragraphs that follow.

For nondirected flow, OFAF:

$$\Delta\Theta_{H,R} = \left(\Delta\Theta_{W/A} - \Delta\Theta_{AO,R}\right) + 5 \tag{H.7A}$$

where

$\Delta\Theta_{AO,R}$	is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{H,R}$	is the hottest-spot conductor rise over top-oil temperature at rated load, °C
$\Delta\Theta_{W/A}$	is the average winding temperature rise over ambient, °C

For directed flow, ODAF:

$$\Delta\Theta_{H,R} = 2.0\left(\Delta\Theta_{W/A} - \Delta\Theta_{AO,R}\right) + 5 \tag{H.7B}$$

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C
$\Delta\Theta_{H,R}$ is the hottest-spot conductor rise over top-oil temperature at rated load
$\Delta\Theta_{W/A}$ is the average winding temperature rise over ambient, °C

And then,

$$\Delta\Theta_{H} = \Delta\Theta_{H,R} K^{2m} \tag{H.8}$$

where

K is the ratio of load to be carried to 100% OFAF nameplate rating
m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.
$\Delta\Theta_{H}$ is the hottest-spot rise above top-oil rise at load to be maintained, °C
$\Delta\Theta_{H,R}$ is the hottest-spot conductor rise over top-oil temperature at rated load, °C

The average winding rise and average oil rise should be obtained from the certified test reports for the maximum nameplate rating.

The hottest-spot temperature at the load to be maintained can be estimated as follows:

$$\Theta_{H} = \Theta_{A} + \Delta\Theta_{TO}\Delta\Theta_{H} \tag{H.9}$$

where

Θ_{A} is the ambient temperature, °C
Θ_{H} is the hottest-spot temperature, °C
$\Delta\Theta_{H}$ is the hottest-spot rise above top-oil rise at load to be maintained, °C
$\Delta\Theta_{TO}$ is the top-oil temperature rise over ambient, °C

It is recommended that Θ_H not exceed 140 °C.

H.4.3 Caution

In using the equations in H.4.2.1, the following factors should be considered during a loss of cooling situation as follows:

a) Much of the normal overload protection (overcurrent relay, etc.) installed on a transformer will be inadequate for this operating condition.

b) The hottest-spot relay (for alarm and in many cases trip), using the two input parameters of phase current and top-oil temperature, is calibrated to a hottest-spot rise over oil with forced-oil circulation in the windings. It will indicate a temperature many degrees lower than actual hottest-spot temperature if there is no forced oil flow in the windings.

c) If the transformer is of directed flow design and pumps have been lost, it may be necessary to hold top-oil temperature well below normal to keep the hottest-spot temperature within its limitation, since, with drastically reduced oil flow, the hottest-spot gradient is greatly increased. Hence, the top-oil temperatures shall be kept lower to stay within the design hottest-spot limitation.

H.5 Forced-oil-cooled transformers with part of coolers in operation

For forced-oil-cooled (OFAF or OFWF) transformer ratings, with part of the coolers in operation, use the reductions in permissible loading given in Table H.1. These permissible loads will give approximately the same temperature rise as full load with all cooling in operation.

Table H.1—Loading capability for OFAF or OFWF transformers

% of total coolers in operation	Permissible load in % of nameplate rating
100	100
80	90
60	78
50	70
40	60
33	50

Annex I

(informative)

Transformer insulation life

I.1 Historical perspectives

In past versions of the guides for loading transformers, much space was dedicated to the subject of “loss-of-life.” The background of this term was not always well understood. Many engineers assumed incorrectly that the “life” in “loss-of-life” referred to the transformer’s life. From the beginning, the important modifier “insulation” frequently has been omitted from the phrase, “loss-of-life.” Actually, loss-of-life has always meant “loss-of-insulation life.” Because this distinction is so important, the user should review the following discussion of the history of loss-of-insulation life.

In the 1920s, but reported in 1930, Montsinger [I17] placed varnished cambric tape insulation into a series of oil-filled test tubes, heated them, and then measured the insulation’s tensile strength. He reported that the life of the varnished cambric was reduced by one half for each 8 °C increase in continuous temperature. The “end-of-life” was defined as the point where the tensile strength of the varnished cambric reached 50% of its initial value. The loss of 50% of initial tensile strength end point was probably chosen because tensile strength was easy to measure. It also varied in about the same manner as other mechanical properties of the early insulations. This is not true of many of the insulating coatings, etc., in common use today. This was an initial signal for engineers to use their slide rules (later calculators and now computers) to make calculations of the expected life of a transformer’s insulation at various operating temperatures to many significant figures beyond the accuracy of the input data.

The end-of-life of a transformer is not determined by a 50% reduction in the tensile strength of its insulation. It has been obvious for some time that transformers with residual insulation tensile strengths well below 20% of initial operate in a completely satisfactory manner. Lamentably, the industry gave far too much credence to Montsinger’s test tube work. In 1944, Montsinger [I18] stated that one should not use aging data at higher temperatures and that the 8 °C rule was incorrect for lower temperatures. He also said, “There is, of course, some question whether laboratory aging tests made on isolated strips of paper in sealed tubes can be applied directly in estimating the life of insulation in a transformer.” Unfortunately, the transformer industry apparently has seemed to ignore this statement.

Later, Dakin [I7] postulated that transformer insulation deteriorated following a modification of Arrhenius’ chemical reaction rate theory. Dakin was probably correct, and a simple “insulation” life curve was developed to relate the insulation’s life at a test temperature to an operating temperature. The industry took Dakin’s work and, unfortunately, Montsinger’s residual tensile strength end-of-insulation life end point and arrived at loss-of-life percentages (without the insulation modifier) based on time at various temperatures. These percentages were badly flawed due to the poorly selected end point; yet, with some slight modifications, they still appeared in recent loading guides without that all-important “insulation” modifier. This happened in spite of a contemporary 1947 paper by Satterlee and Reed [I19] whose tests showed that insulation, in a sealed tank of oil with no load but exposed to ambient temperatures only, experienced a reduction of tensile strength to 20% of initial in about 2.5 years.

The data on the loss-of-insulation life curves shown in the different guides differed considerably. For example, although both distribution and power transformers use the same insulation, the loss-of-insulation life curves in the guides show a considerable variation for a specific temperature. The insulation life of distribution transformers is listed as being several times greater than the power transformer’s guide insulation life.

In summary, loss-of-life data in previous guides was based, in part, on observations made 60–70 years ago, on obsolete materials, test tube data, and an inferior refined oil. In addition, the original investigator repudiated the data in the 1940s.

In the mid-1950s, a task force of the AIEE Transformers Committee composed of the manufacturers and users of distribution and power transformers undertook the most comprehensive examination of transformer life to date.

Sample distribution transformers of each manufacture were subjected to a series of carefully selected loading tests at a number of different manufacturing locations. The data from each of the investigators was coded to preserve the supplier's identity and sent to a neutral data compiler for review by the task force. It was initially planned by the task force to subject the transformer test models to alternate back-to-back loading and cooling cycles at three carefully determined hottest-spot conductor temperatures to determine their straight line life characteristic in accordance with reaction rate theory. The temperatures selected were 220 °C, 180 °C, and 140 °C. The test duration at each temperature was determined by current theory. The temperature was controlled by a monitor of exactly the same design containing thermocouples located throughout the windings and tank. After thermal cycling, each test model received "product" tests; the monitor received no product tests except oil analysis. The test end point was established as failure during any one of the product tests.

The 220 °C models were aged first to obtain a better estimate of the test duration for subsequent temperatures. To the surprise of many task force members, the 220 °C models survived many more cycles than expected. The variability between manufacturers was quite large as expected. The next series at 180 °C hottest-spot temperature was started at lengthened test duration and sure enough, the models continued to pass test cycle after cycle beyond expectation. Using end point times from the very first 180 °C failures to be reported, the task force predicted both an unacceptably long test cycle for the 140 °C models and a projected standard "life" exceeding hundreds of thousands of hours at normal rated temperature. Many manufacturers discontinued the 180 °C cycles. Others continued to run the tests for their own purposes. Although the end point tests included impulse and low-frequency withstands and short-circuit and visual examination, many of the investigators reported short circuits particularly in the end turns as the ultimate failure mode. Investigation showed this to be true long after nearly total dielectric strength reduction of the insulating system.

Since at least three test temperatures were not obtained from which to extrapolate the life characteristics of the tested systems; and as the "end-of-life" points reached at the 220 °C and 180 °C aging temperatures were significantly longer than anticipated, the task force, after much discussion, arbitrarily redefined the life curve for distribution transformers and supported the subsequent recommendation of the even more conservative power transformer life line.

A careful review of this history has been coupled with recent findings based on work done on model power transformers on two extensive EPRI transformer loading research projects ([I2], [I3]). Some results of this review have been as follows:

a) The reviewers have decided that the insulation life curves for distribution and power transformers are similar.
b) The insulation life curves for distribution and for power transformers, which were found in their respective previous guides, are not appropriate for modern transformer loading guides, but should be included in a future revision of IEEE Std C57.100 for thermal evaluation comparisons of the new insulation system.
c) The chemical test measurement of degree of polymerization (DP) is a much better indication of cellulosic insulation mechanical characteristics than loss of tensile strength.

I.2 Thermal aging principles

The principal constituent of most transformer conductor insulation materials is cellulose, an organic compound whose molecule is made up of a long chain of glucose rings or monomers (Fabre and Pinchon [I8], Shroff and Stannet [I20], Lampe and Spicar [I12], Beavers, Rabb, and Leslie [I5]. Degree of molecular polymerization refers to the average number of glucose rings in the molecule and it typically ranges from 1000–1400 for new material. A single cellulose fiber will contain many of these long chains and the mechanical strength of the fiber, and hence of its parent material, is closely related to the length of the chains. Thus, the degree of polymerization is a good measure of retained strength and functionality of cellulose.

As cellulose ages thermally in an operating transformer, three mechanisms contribute to its degradation, namely hydrolysis, oxidation, and pyrolysis (Shroff and Stannet [I20], Lampe and Spicar [I12]). The agents responsible for the respective mechanisms are water, oxygen, and heat. Each of these agents will have an effect on degradation rate so they must be individually controlled. Water and oxygen content of the insulation can be controlled by the transformer oil preservation system, but control of heat is left to transformer operating personnel.

Since the early days of transformer manufacture, the deterioration of mechanical properties as a result of thermal aging has been recognized. Montsinger [I17] published early aging data and made an observation about the aging rate that has been widely used. He noted that the rate of deterioration of mechanical properties doubled for each 5–10 °C increase in temperature. The doubling factor was not a constant, being about 6 °C in the temperature range from 100–110 °C and 8 °C for temperatures above 120 °C. However, people tend to remember the doubling factor as a constant and the present IEC Loading Guide [I11] uses 6 °C.

In 1948, Dakin [I7] made a more significant advance in defining insulation aging rates by recognizing that aging of cellulose is the result of a chemical reaction, so the rate of change of a measured property can be expressed in the form of a reaction rate constant K_o. This can be applied by multiplying the rate constant, a function of temperature, by the time interval over which the aging takes place to find the percentage change in a property. Mathematically, the rate constant can be expressed by

$$K_O = A' \mathrm{e}^{\left[\frac{B}{\Theta + 273}\right]} \tag{I.1}$$

where

A' and B	are empirical constants
Θ	is the temperature in °C

Dakin showed that all aging rate data being compared in an AIEE committee, including Montsinger's data, could fit this relationship. The Dakin relationship, sometimes referred to as the Arrhenius reaction rate equation, has found wide acceptance in the world technical community in the ensuing years.

When the approach discussed is to be used for transformer life definition, there are two aspects involved, the first being the aging rate and the second being the life end-point criterion. These may be separated by treating life as a per unit quantity with the following as a life definition

$$Per\ Unit\ Life = A\, \mathrm{e}^{\left[\frac{B}{\Theta_H + 273}\right]} \tag{I.2}$$

where

A	is a modified per unit constant, derived from the selection of 110 °C as the temperature established for "one per unit life"
B	is the same aging rate slope as Equation (I.1)
Θ_H	is the hottest-spot temperature, °C

This equation expresses the dependence of the aging rate on temperature alone, and the absolute definition of "one per unit life" in units of time can encompass the end-point criterion and the other variables that affect the time to reach that end point, namely water and oxygen content of the insulation system. Each of these aspects may be discussed separately.

Many investigators have measured cellulose aging rates under controlled conditions and have presented their results in the above form. Some measured mechanical properties, some measured DP, and some measured gas evolution rates. To use the reaction rate constant for loading guide purposes, it is desirable to select a single rate slope, the constant B, which would be reasonably accurate for all forms of cellulose. Table I.1 represents the results of a search of the published literature to find that slope.

Dakin's and Sumner's data appear to have been shared within an AIEE committee. Head's observations were most interesting in that he found that the B constants for mechanical properties (tensile strength, burst strength, elongation to rupture), DP and gas evolution were all the same within a range of ±440. Most of these data appear to be for non-thermally upgraded paper, but Lampe also evaluated thermally upgraded paper. His B constant in the table is one of the lowest, but his constant for thermally upgraded paper was even lower (9820). This could be the result of a limited temperature range of measurement, 135 °C–155 °C, from which it would be difficult to find an accurate slope. In recent evaluations to qualify thermally upgraded papers in the U.S. the data falls reasonably close to the slope of IEEE Std C57.92-1981. It should be pointed out that the ASA C57.92-1948 curve was not an Arrhenius curve, so it does not have a single value of *B* for all temperatures.

Table I.1—Aging rate constant—*B*

Source	Basis	*B*
Dakin [I7]	20% tensile strength retention	18 000
Sumner, et al. [I21]	20% tensile strength retention	18 000
Head, et al. [I10]	Mechanical/DP/gas evolution	15 250
Lawson, et al. [I14]	10% tensile strength retention	15 500
Lawson, et al. [I14]	10% DP retention	11 350
Shroff [I20]	250 DP	14 580
Lampe, et al. [I13]	200 DP	11 720
Goto, et al. [I9]	Gas evolution	14 300
ASA C57.92-1948	50% tensile strength retention	14 830 [a]
IEEE Std C57.92-1981	50% tensile strength retention	16 054
IEEE Std C57.91-1981	DT life tests	14 594

[a]120 °C to 150 °C temperature range.

From Table I.1 it may seem that there is not a single “right” value of *B*, but it must be remembered that all experimental data is subject to variability and the materials and test conditions for all of the investigators were certainly not identical. Placing the most emphasis on the more modern data (Shroff and Stannet [I20], Goto, Tsukioka, and Mori [I9], Head, Gale, and Lawson [I10]), it seems that a value of *B* of 15 000 would be appropriate and is used in the transformer insulation life curve in this loading guide.

For small distribution transformers, it is possible to define an end point for insulation life by means of functional life tests on the actual apparatus, as was done in the 1960s. However, this is not economically practical for power transformers. Another option is to make the definition in terms of a measurable physical characteristic—mechanical, electrical, or chemical. It can involve a percentage retention of the characteristic or an absolute level of the characteristic that is judged to be essential for functionality. Dielectric strength is the characteristic that would relate most closely to functionality, but it has been found that it deteriorates very slowly if the insulation is not disturbed mechanically. Thus, a mechanical characteristic, usually tensile strength, has customarily been chosen with an end-point criterion of 50% retained tensile strength. However, this has a deficiency in that 50% retained strength for initially weak paper could be a lower absolute strength than 25% retained strength for initially strong paper.

Functional life test evaluations on power transformer models were sponsored by EPRI in the 1978 to 1982 time period (EPRI [I2], EPRI [I3], and McNutt and Kaufman [I16]). They demonstrated that the ANSI 50 %-retained tensile-strength life criterion is very conservative. In one program (EPRI [I2], McNutt and Kaufman [I16]), small disk coils were aged for 6.2 times ANSI life without failure on short circuit and dielectric end-point tests. The aged coils had suffered only a 10% reduction of the initial dielectric strength. In a separate program (EPRI [I3]), disk windings were aged for 8.6, 12.0, and 15.3 ANSI life (see IEEE Std C57.92-1981) without failure on short-circuit and dielectric end-point tests.

An alternative end-point criterion, an absolute level of DP, has the advantages that only a small sample is required, measurement is simple, and the results tend to have less dispersion than tensile strength measurements. Many investigators (Fabre and Pichon [I8], Head, Gale, and Lawson [I10], Lampe and Spicar [I12], Lawson, Simmons, and Gale [I14], Yoshida, et al. [I22]) have shown good correlation between reduction of mechanical properties and reduction of DP. Using DP, an end-point criterion can be selected based on subjective judgment of “loss of useful mechanical properties.” Various investigators Bozzini [I6], Fabre and Pichon [I8], Lampe, Spicar and Carranger [I13], Shroff and Stannet [I20], tend to choose different levels of DP for the endpoint, ranging from 100 to 250. A value of 200 seems a good compromise for power transformers, but smaller transformers subjected to lower mechanical stress levels in service could possibly accept a lower limit. Some small transformers have continued operation in service with DP below 100 (Bassetto and Mak [I4]).

Selection of an absolute value for useful life of transformer insulation at the reference temperature of 110 °C is very subjective. The general feeling at present is that the definition of 65 000 h given in IEEE Std C57.92-1981 (and earlier versions) may be excessively conservative. This value was chosen based on time to 50% tensile strength reduction of the insulation in sealed tube aging tests. The functional life tests on power transformer models previously mentioned confirmed that 65 000 was extremely conservative, perhaps by a factor of 2 or 3. At various times during the early deliberations about loading guides, lower levels of residual tensile strength were considered for the end point in sealed tube aging tests, down to a level of 20% residual (Sumner, Stein, and Lockie [I21]). At that level, the life could be considered to be 150 000 h and would be approximately equivalent to an end-point criterion of 200 residual DP. A slightly more conservative end point would be 25% residual tensile strength at a life of 135 000 h.

Functional life testing of distribution transformers was begun in 1957 (Acker [I1]) to evaluate the life of 55 °C average winding rise insulation in that product. A factor of safety of 5 was applied to the most pessimistic results to obtain a life definition for distribution transformers of 180 000 h at 95 °C. More recent tests by individual manufacturers on the 65 °C average winding rise insulation system distribution transformers have demonstrated a similar useful life at 110 °C. The normal life of 180 000 h has been used in this standard for many years.

Both the results of functional tests and service experience suggest that a normal life of 15–20 years at a winding hot spot temperature of 110 °C is a reasonable expectation for both distribution and power transformers with well-dried and oxygen-free insulation systems. A 20-year life has long standing in the loading guides for distribution transformers. When an absolute value is placed on time to reach a selected life end point, the effect of all of the significant variables must be considered, namely heat, water, and oxygen. Accelerated material aging tests that formed the basis for the traditional IEEE Std C57.92-1981 life curves (time to 50% retained tensile strength) were always carried out with very low moisture and oxygen contents in the aging cell. The same can be said for power transformer models and distribution transformers subjected to functional life tests. However, such is not always the case for in-service transformers, particularly those older units with open conservator oil preservation systems. An end of functional life criterion must, therefore, reflect not only a suitable end-point measurement level, but also appropriate moisture and oxygen levels in the insulation system of the operating transformer. For modern, well-sealed systems, these levels are comparable to those in the sealed cell material life evaluation tests.

The effect of the two controllable variables, water and oxygen, on aging rates has been extensively investigated. Fabre and Pichon [I8] stated a very simple rule for the effect of water, namely that the deterioration rate is directly proportional to the water content. Shroff's and Stannet's data [I20] supports that relationship. The reference moisture level typical for material aging tests is 0.2% to 0.3% by weight, so the deterioration rates must be proportionally increased for higher moisture levels in operating transformers. However, the moisture level at the critical location, the hottest spot, is typically only about half of the average moisture level, because of moisture partitioning by temperature. Fabre and Pichon [I8] also investigated the effect of oxygen, comparing deterioration rates for a sealed low oxygen content system to an open free-breathing system. He found a deterioration acceleration factor of 2.5 for the open system. In a similar study, Lampe et al. [I13] found a factor of 10. All of these data give utilities good incentive to employ an oil preservation system that maintains low moisture and oxygen levels in their transformers.

Water, heat, and oxygen are the catalyst, the accelerator, and the active reagent in the oxidation of the oil in oil-filled transformers. The products of oil oxidation are acids, esters, and metallic soaps that attack the cellulose insulation with vigor and tenacity. The oxidation by-products also attack the oil producing additional oxidation by-products. If failures of the oil preservation system occur (loss of tank seal), then oil oxidation that dramatically accelerates insulation deterioration can be expected.

To summarize, the effect of heat on the useful life of a cellulose insulation material can be estimated on a per unit basis without regard to end-of-life criteria or internal conditions in the insulation system using Equation (I.2). Cumulative loss-of-life can be calculated for varying load conditions on this relative basis (see Table I.3 and Table I.4), with the result that one real day of operation will produce less or more aging than one day at the reference temperature of 110 °C (for a 65 °C average winding rise insulation system).

During development of the 1995 revision of IEEE Std C57.91, after the working group agreed to combine the existing separate guides into one document, some users of power transformers were concerned about the effect of dropping the old life curve for power transformers and adopting the life curve for distribution transformers. Their concern was the effect on the calculations of the insulation loss of life. To alleviate those concerns, the Working Group developed a table of alternative end of life values that the user could choose from, when performing loss of insulation life calculations. The authors failed to adequately explain why the table was created. That table is now included in this annex to document the historical information.

Table I.2—Options offered in the 1995 revision of IEEE Std C57.91—Normal insulation life of a well-dried oxygen-free 65 °C average winding temperature rise system at the reference temperature of 110 °C

Basis	Normal insulation life	
	Hours	Years
50% retained tensile strength of insulation (former IEEE Std C57.92-1981 criterion)	65 000	7.42
25% retained tensile strength of insulation	135 000	15.41
200 retained degree of polymerization in insulation	150 000	17.12
Interpretation of distribution transformer functional life test data (former IEEE Std C57.91-1981 criterion)	180 000	20.55
NOTE 1— Tensile strength or degree of polymerization (D.P.) retention values were determined by sealed tube aging on well-dried insulation samples in oxygen-free oil. NOTE 2 — Per IEEE Std C57.12.00-2010 (5.11.3) a minimum normal insulation life of 180 000 h is required. Other end of life criteria have been used historically for developing transformer loading. They are provided above for reference.		

I.3 Example calculations

In the first example (see Table I.3) with a mild overload, the life consumption was about 107.7% of one day at reference temperature, while for the short-time emergency load in Table I.4, with hottest-spot temperature rising to 180 °C for a very brief time, the life consumption was about 18.6 times that of one day at reference temperature. It should be noted that in the development of Table I.3 and Table I.4 and in the sample calculation, the hot spot temperature that was used was that for the end of each hour, with the assumption made that the temperature was constant for the full hour. In reality, the hot-spot temperature will vary during any one hour of loading. If this variation is small, there is little error in the calculation of aging hours, but if the variation is larger, such as 5 ° C–10 °C, or more as around the hour 17:00 in Table I.4, the error can be significant. To minimize this error, it is recommended that a computer program be used in which the aging hours are calculated in small increments, such as every 3 min or 5 min.

One example of the use of the aging acceleration factor (FAA) would be for planned overloading. A 24 h variable load cycle would be input, which consists of variable loads and ambient temperature. The ambient and peak load might be high during the day and reduced during the night. Also an equivalent aging factor for a summer load cycle might be averaged with an equivalent aging factor for the winter. If the average was 1.0 for the year, then the kVA purchased was correct. If the average was above 1.0, then a higher kVA should be purchased. Or, economics might be factored in and the best return on the investment would be achieved by loading to, say, a 1.1 equivalent aging factor, which would accelerate slightly the use of the life of the unit and recover the investment more quickly. The user could then buy a newer transformer with more up-to-date technology if the old one failed due to this loading or other reasons.

In order to apply an absolute time scale to the life measurement, an appropriate end-of-life criterion must be selected. Tensile strength retention of 50% would be conservative and a lesser level could be accepted. Alternatively, an absolute level of DP, such as a value of 200, could be chosen as a level at which "useful mechanical properties" of the cellulose are still retained. In the Table I.4 example, the absolute percentage of total life lost in this 24 h period is given for the four "normal life" optional values for the user to choose from suggested in 9.1. In making this calculation, the aging acceleration effects of moisture and oxygen must be considered if these parameters are not maintained at low levels.

Table 1 of Clause 5 gives aging acceleration factors.

This annex is based largely on a condensation of material presented in McNutt [I15].

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{25.857}{24} = 1.077$$

where

F_{EQA}	is equivalent aging factor for the total time period
$F_{AA,n}$	is aging acceleration factor for the temperature that exists during the time interval Δt_n
n	is index of the time interval, Δt
N	is total number of time intervals
Δt_n	is time interval, h

This is equivalent to aging of 1.077 days or 25.848 hours at 110 °C.

$$\%\text{Loss of Life} = \frac{F_{EQA} \times 24 \times 100}{\text{Normal Insulation Life}} = \frac{1.077 \times 24 \times 100}{180{,}000} = 0.014\%$$

Based on normal insulation life of 180 000 h.

Table I.3—24 h load cycle aging calculation mild overload 100 MVA transformer (65 °C rise)

Time	Load (P.U. of N.P.)	Hot-spot temp. °C	Aging acel factor $F_{AA,n}$	Aging hours	Cumulative age hours
1:00	0.599	80.0	0.036	0.036	0.036
2:00	0.577	72.8	0.015	0.015	0.051
3:00	0.555	72.9	0.015	0.015	0.066
4:00	0.544	72.8	0.015	0.015	0.080
5:00	0.544	71.8	0.013	0.013	0.093
6:00	0.566	71.8	0.013	0.013	0.107
7:00	0.655	73.0	0.015	0.015	0.122
8:00	0.844	74.2	0.018	0.018	0.139
9:00	0.955	85.1	0.066	0.066	0.205
10:00	1.021	92.2	0.148	0.148	0.353
11:00	1.054	99.1	0.318	0.318	0.671
12:00	1.077	104.6	0.571	0.571	1.242
13:00	1.088	109.2	0.921	0.921	2.163
14:00	1.099	112.8	1.329	1.329	3.492
15:00	1.099	116.0	1.830	1.830	5.322
16:00	1.110	117.8	2.185	2.185	7.507
17:00	1.200	125.0	4.376	4.376	11.882
18:00	1.077	130.0	6.984	6.984	18.866
19:00	0.977	125.0	4.376	4.376	23.242
20:00	0.910	114.0	1.499	1.499	24.741
21:00	0.877	104.8	0.583	0.583	25.324
22:00	0.866	97.9	0.279	0.279	25.603
23:00	0.832	93.2	0.166	0.166	25.769
24:00	0.788	87.6	0.088	0.088	25.857

Table I.4—24 h load cycle aging calculation short time emergency 100 MVA transformer (65 °C rise)

Time	Load (P.U. of N.P.)	Hot-spot temp. Deg. °C	Aging acel factor $F_{AA,n}$	Aging hours	Cumulative age hours
1:00	0.599	80.0	0.036	0.036	0.036
2:00	0.577	72.8	0.015	0.015	0.051
3:00	0.555	72.9	0.015	0.015	0.066
4:00	0.544	72.8	0.015	0.015	0.080
5:00	0.544	71.8	0.013	0.013	0.093
6:00	0.566	71.8	0.013	0.013	0.107
7:00	0.655	73.0	0.015	0.015	0.122
8:00	0.844	74.2	0.018	0.018	0.139
9:00	0.955	85.1	0.066	0.066	0.205
10:00	1.021	92.2	0.148	0.148	0.353
11:00	1.054	99.1	0.318	0.318	0.671
12:00	1.077	104.6	0.571	0.571	1.242
13:00	1.088	109.2	0.921	0.921	2.163
14:00	1.099	112.8	1.329	1.329	3.492
15:00	1.099	116.0	1.830	1.830	5.322
16:00	1.110	117.8	2.185	2.185	7.507
17:00	1.690	180.0	424.922	424.922	432.429
18:00	1.077	130.0	6.984	6.984	439.413
19:00	0.977	125.0	4.376	4.376	443.789
20:00	0.910	114.0	1.499	1.499	445.288
21:00	0.877	104.8	0.583	0.583	445.871
22:00	0.866	97.9	0.279	0.279	446.150
23:00	0.832	93.2	0.166	0.166	446.316
24:00	0.788	87.6	0.088	0.088	446.403

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{446.403}{24} = 18.6$$

$$\%\text{Loss of Life} = \frac{F_{EQA} \times 24 \times 100}{\text{Normal Insulation Life}} = \frac{18.6 \times 24 \times 100}{180{,}000} = 0.248\%$$

Using the normal life selections from Table I.2 gives the following:

a) 65 000 h = 0.687%
b) 135 000 h = 0.331%
c) 150 000 h = 0.298%
d) 180 000 h = 0.248%

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