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IEEE Guide for Loss Evaluation of Distribution and Power Transformers and Reactors

IEEE Power and Energy Society

Sponsored by the
Transformers Committee

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USA

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(Revision of IEEE Std C57.120-1991)

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Abstract: The economic loss evaluation of liquid-filled distribution and power transformers, dry-type distribution and power transformers, and reactors is covered in this guide.

Keywords: economic evaluation, IEEE C57.120™, losses, reactor, transformer

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Introduction

This introduction is not part of IEEE Std C57.120-2017, IEEE Guide for Loss Evaluation of Distribution and Power Transformers and Reactors.

This guide provides details and explanations for determining the constituent components and the methodology for determining the economic value of losses of distribution and power transformers and reactors for both utility and non-utility segments. This guide focuses on the cost of losses from the energy consumption of equipment perspective and does not provide methods to quantify other social or environmental benefits that could be related to equipment efficiencies.

Losses are quantified typically for the purposes of purchasing evaluation or replacement cost analysis. It is important to quantify losses because manufacturers of equipment have a large number of design options available to them and, by providing loss values from the user, it will help the manufacturer to propose the most economic design to fit the user's circumstances.

Loss evaluation is a means to quantify operating cost and is an economic decision. Quantifying losses for comparison is a straightforward process, however, the information required for such evaluation involves forecasting and prediction of costs over a future timeframe. There are many sources of this information available and it is up to the evaluator to identify and select the most appropriate source of data applicable to their circumstances. Economic circumstances are constantly changing and specific to each user's situation, making it impossible for any single number to be used everywhere for loss evaluation.

Prediction of future costs and forecasting requires frequent updating and it is up to the evaluator to use the best information available to determine their own values of losses.

In addition to the identification of value, the evaluator is identified as a reasonable evaluation timeframe. For example, the time period of evaluation may be the useful life of the equipment or be limited to the useful life of the facility or limited by internal corporate investment criteria. The determination of an evaluation time period is entirely dependent on the user and their circumstances.

This guide identifies parameters to consider when performing a loss evaluation, but it is up to the user to identify the parameters most applicable to their circumstances. To provide an example, a primary service transformer in an industrial plant may only have losses evaluated on the basis of energy cost charged to the facility, but an industrial user may include a loss-on-loss factor for secondary step-down transformers in the same facility and include some of the evaluation parameters for distribution transformers.

Merchant generating plants may not need to calculate the parameters associated with transmission assets or the loss-on-loss multipliers for the generator's transformer because their plant is metered at the transmission connection point and the losses in the generation plant transformers only take away from the plant's revenue capability.

This guide will assist the user to decide how to value the efficiency of equipment. Ultimately, the efficiency depends heavily on how the equipment is used, where on the power system it is used, and what decisions are made regarding operating conditions such as loading beyond nameplate and timing of asset additions/replacement. One shall make the selection of parameters for the evaluation based on the best available knowledge.

This guide uses publicly available information on wholesale electricity prices, transformer costs, and other dollar values. These numbers are provided for illustrative purposes only. Actual price (or cost) will vary by time and location. Each user of this guide should determine the price or cost values that he or she believes appropriate for making loss evaluations.

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IEEE Guide for Loss Evaluation of Distribution and Power Transformers and Reactors

1. Overview

1.1 Scope

This guide covers the economic loss evaluation of liquid-filled distribution and power transformers, dry-type distribution and power transformers, and reactors.

1.2 Purpose

The purpose of this guide is to provide a method of establishing the dollar value of the electric power needed to supply the losses of a transformer (includes distribution and power transformers as well as reactors in this guide). Users can use this loss evaluation to determine the relative economic benefit of a high-first-cost, low-loss unit versus one with a lower first cost and higher losses. Manufacturers can use the evaluation to optimize the design and provide the most economical unit to bid and manufacture. The evaluated cost of losses also enables a user to compare the offerings of two or more manufacturers to aid in making the best purchase choice among competing transformers. Loss evaluation also provides information to a user for establishing the optimum time to retire or replace existing units with modern low-loss transformers. The user should determine, on a dollars-per-kilowatt basis, the sum of the present worth of each kilowatt of losses of a transformer throughout its life, or some other selected period of time. A portion of this evaluated cost can be paid to the manufacturer to reduce losses. However, this evaluated cost includes other costs associated with owning a more expensive piece of equipment, such as financing costs, taxes, etc. This guide provides formulas by which the costs of energy, power, money, and the loading pattern of a transformer can be converted to dollars-per-kilowatt values of the transformer losses.

These dollars-per-kilowatt figures should be furnished to the manufacturer when bids are requested. If the final tested values of losses vary from the manufacturer's guaranteed values, economic adjustments may be made. Nothing in this guide is mandatory. It should not be inferred that the methodology described in this guide is the only valid methodology for computing the cost of transformer losses. Many users have developed their own transformer loss evaluation techniques that are suitable for the intended purpose.

This guide uses publicly available information on wholesale electricity prices, transformer costs, and other dollar values. These numbers are provided for illustrative purposes only. Actual price (or cost) will vary by time and location. Each user of this guide should determine the price or cost values that it believes appropriate for making loss evaluations.

This guide offers a methodology to determine, and thereby specify, the economic value of no-load, load, and auxiliary losses. The use of this guide allows manufacturers to tailor the design to the unique economic situation of each user, and allows the user to evaluate multiple designs.

2. Definitions, acronyms, and abbreviations

2.1 Definitions

For the purposes of this document, the following terms and definitions apply. For other terms, the standard transformer terminology in IEEE Std C57.12.80 [B4][1] applies. Other electrical terms are defined in the *IEEE Standards Dictionary Online*.[2]

avoided cost of energy: The levelized avoided (incremental) cost for supplying the next kilowatt hour, which may be produced by the utility's generating units or purchased from an energy supplier.

avoided cost of system capacity: The levelized avoided (incremental) cost of generation, transmission, and primary distribution capacity required to supply the next kilowatt of load to the transformer coincident with the peak load.

capital recovery factor: The ratio of a constant annuity to the present value of receiving that annuity for a given length of time.

cost: The amount of money that is needed to pay for or buy something.

escalation: The compounded price for a future cost based on current costs and inflation.

first cost: The sum of the initial expenditures involved in capitalizing a property; includes items such as transportation, installation, preparation for service, as well as other related costs.

fixed charge rate: The cost of carrying a capital investment which consists of the cost of capital, stocks, bonds, depreciation, taxes, and insurance.

hours per year: Used in the A-factor (no-load loss $/watt) and B-factor (load loss $/watt) equations and is generally taken as 8760 h. There may be exceptions that would use a lesser value.

levelized annual peak load: The levelized annual peak load seen by the transformer that is equivalent to the function of an initial peak load with an estimated load growth rate and a maximum allowable load before changeout is required.

loss multiplier: A measure of system losses from generation through the transmission and distribution system, to the point where the transformer under evaluation is installed. This number will be greater than or equal to one.

peak responsibility factor: A function of the relationship between the transformer peak load and the transformer load at the time of system peak load.

present value factor: Today's value of a future (single) cost.

present worth factor: Today's value of a future annuity (a uniform series of future costs).

transformer loss factor: Ratio of the annual average load losses to the peak value of load losses on the transformer.

[1]The numbers in brackets correspond to those of the bibliography in Annex C.
[2]*IEEE Standards Dictionary Online* is available at: http://dictionary.ieee.org/.

2.2 Acronyms and abbreviations

$	cost that is representative of any form of currency to be used (USD, CAD, Euro, etc.)
A	equivalent first cost of no-load losses ($/W)
AHPY1	hours of operation for stage 1 cooling per year
AHPY2	hours of operation for stage 2 cooling per year
AL	auxiliary losses (watts)
AL1	auxiliary loss of stage 1 cooling (watts)
AL2	auxiliary loss of stage 2 cooling (watts)
A/P	capital recovery factor
B	equivalent first cost of load losses ($/W)
CAF	compound-amount factor
CIF	compound-interest factor
CRF	capital recovery factor ($)
DC	avoided cost of distribution capacity ($/kW per year)
EC	avoided cost of energy ($/kWh)
EC_L	levelized avoided cost of energy ($/kWh)
EFC	equivalent first cost ($)
ESC	escalation (%)
FC	first cost
FCR	fixed charge rate (%)
FCR_L	levelized fixed charge rate (per-unit)
GC	avoided cost of generation capacity ($/kW per year)
HPY	hours per year energized
i	interest rate or cost of capital (%)
IPP	independent power producers
LL	load loss of the equipment (watts)
LM	loss multiplier (per-unit)
LSF	transformer loss factor (per-unit)
NL	no-load loss of the equipment (watts)
P	bid price
P/F	present value of a future cost
PL	equivalent annual peak load (watts)
PL_L	levelized annual peak load (per-unit)
PVF	present value factor
PW	present worth cost ($)
PWF	present worth factor

PW(IS)	present worth of an inflation series
RF	peak responsibility factor
SC	avoided cost of system capacity ($/kW per year)
SC_L	levelized avoided cost of system capacity ($/kW per year)
SFF	sinking-fund factor
TC	avoided cost of transmission capacity ($/kW per year)
TOC	total owning cost ($)

3. Loss evaluation parameters

3.1 General

As noted in the introduction, these procedures were first developed in the early 1970s. Since that time, there have been some significant changes in the utility industry in the U.S. and other countries. Most of those changes are not reflected in the description and the calculation procedures found in the guide.

Today, nearly all utility systems have provisions, and accounting processes, for accommodating generation capacity of independent power producers (IPP) connected to their systems. The portions of the calculations procedures that refer to the avoided cost of energy and avoided cost of generating capacity may need to be reevaluated by the transformer purchaser as there may be a need to analyze the effects and or costs of the IPP rather than using the material that now appears in the existing Clause 3. The methodology provided in Clause 4 should be reviewed by the user of this guide whenever non-vertically integrated generation or transmission arrangements are in effect.

The process of deregulation of the electric utility business has been implemented in a variety of forms across the U.S. In cases of full deregulation, there are now transmission and distribution companies that provide energy delivery services only. They do not generate or buy wholesale power and resell it. Therefore, they do not generate power or purchase it. In these cases the customer connects directly with an energy provider. The customer pays the energy provider for the energy consumed and pays a transmission and distribution delivery charge to the electric delivery company. The amount of energy consumed by system losses and particularly the transformers does not affect the financial statements of the company. So for them, avoided cost of energy, avoided cost of generation capacity, and avoided cost of system capacity are all $0. Therefore, the calculations of the A factor (equivalent first cost of no-load losses) and B factor (equivalent first cost of load losses) will produce results of $0. Because using zero as the A and B factors results in a lower efficiency transformer, alternative methods of determining the parameters are possible.

Suggestions for possible sources of data to develop parameters for the calculations are discussed in Clause 4 of this guide.

3.2 Total owning cost (TOC)

The TOC is the equivalent first cost of acquiring and operating a transformer or reactor over the predicted life of the equipment, as shown in Equation (1):

$$TOC = P + A \times NL + B \times LL + B1 \times AL1 + B2 \times AL2 \tag{1}$$

where

P	is the cost of acquiring the equipment
A	is the equivalent first cost of no-load losses, per watt

B is the equivalent first cost of load losses, per watt
$B1$ is the equivalent first cost of stage 1 auxiliary losses, per watt
$B2$ is the equivalent first cost of stage 2 auxiliary losses, per watt
NL is the no-load loss of the equipment (watts)
LL is the load loss of the equipment (watts)
$AL1$ is the auxiliary loss of stage 1 cooling (watts)
$AL2$ is the auxiliary loss of stage 2 cooling (watts)

3.3 Cost of no-load losses (A)

The cost of no-load losses, which is referred to in this guide as the A factor, can be calculated as follows in Equation (2):

$$A = \frac{SC + EC \times HPY}{FCR \times 1000} \times LM \tag{2}$$

where

SC is the levelized avoided cost of system capacity ($/kW per year)
EC is the levelized avoided cost of energy ($/kWh)
HPY are the hours of operation per year
FCR is the fixed charge rate (%)
LM is the loss on loss multiplier (per-unit)

3.4 Cost of load losses (B)

The cost of load losses, which is referred to in this guide as the B factor, can be calculated as follows in Equation (3):

$$B = \frac{[(SC \times RF) + (EC \times LSF \times HPY)] \times (PL_L)^2}{FCR \times 1000} \times LM \tag{3}$$

where

SC is the levelized avoided cost of system capacity ($/kW per year)
EC is the levelized avoided cost of energy ($/kWh)
HPY are the hours of operation per year
FCR is the fixed charge rate (%)
RF is the peak responsibility factor (per-unit)
LSF is the transformer loss factor (per-unit)
PL_L is the levelized annual peak load (per-unit)
LM is the loss on loss multiplier (per-unit)

3.5 Cost of auxiliary losses (B1, B2)

The cost of auxiliary stage 1 losses and auxiliary stage 2 losses, which is referred to in this guide as the B1 and B2 factors, can be calculated as follows in Equation (4) and Equation (5):

$$B1 = \frac{[(SC \times RF) + (EC \times LSF \times AHPY1)] \times (PL_L)^2}{FCR \times 1000} \times LM \tag{4}$$

$$B2 = \frac{[(SC \times RF) + (EC \times LSF \times AHPY2)] \times (PL_L)^2}{FCR \times 1000} \times LM \tag{5}$$

where

SC	is the levelized avoided cost of system capacity ($/kW per year)
EC	is the levelized avoided cost of energy ($/kWh)
HPY	are the hours of operation per year
AHPY1	are the hours of operation for stage 1 cooling per year
AHPY2	are the hours of operation for stage 2 cooling per year
FCR	is the fixed charge rate (%)
RF	is the peak responsibility factor (per-unit)
LSF	is the transformer loss factor (per-unit)
PL_L	is the levelized annual peak load (per-unit)
LM	is the loss on loss multiplier (per-unit)

Ultimately, the evaluation of losses is an economic exercise that, in most cases, will be dictated by corporate policies and local requirements. So simpler is better, but the user should identify the factors to be considered (or rejected) in the evaluation.

3.6 Equipment parameters

3.6.1 Bid price (P)

The bid price is the cost to acquire the transformer from the supplier. Transformer suppliers provide the transformer price when responding to requests for quotation. Some evaluators add the cost of sales tax, or other percentage adders to the transformer price. An example might be the price of design engineering as a percent of the total project cost for Engineering, Procurement, and Construction (EPC) or design/build construction projects. Another example might be the Construction Work In Progress (CWIP), which accounts for the cost of funds during construction. Care should be taken so that this is not accounted for twice in the evaluation since the cost of capital may already include an allowance for items beyond the price of the transformer.

3.6.2 No-load losses (NL)

No-load losses (in watts) are the excitation losses at rated voltage that occur on all energized transformers and are continuous, independent of load. No-load losses include dielectric loss, conductor loss in the winding due to exciting current, conductor loss due to circulating current in parallel windings, and core loss. Core loss is the power dissipated in a magnetic core subjected to a time-varying magnetizing force. Core loss includes hysteresis and eddy current losses of the core. These losses change with the excitation voltage, and may increase sharply if the rated voltage of the transformer is exceeded. The no-load losses also increase as the temperature of the core decreases. No-load losses should be expressed as guaranteed average values for the lot of units purchased specified at 20 °C.

3.6.3 Load losses (LL)

Load losses (watts) should be expressed as guaranteed average values for the lot of units purchased at the rated average winding temperature rise plus an annual average ambient, usually 20 °C. For a unit operating at 65 °C rise with a 20 °C ambient, losses would be specified at 85 °C. However, for many distribution transformers the actual winding rise may be significantly less than the nameplate average winding rise.

Load losses include I^2R loss in the winding due to load and eddy currents, stray loss due to leakage fluxes in the windings, core clamps, other parts, and the loss due to circulating currents (if any) in parallel windings or in parallel winding strands. These losses are often referred to as “copper losses,” although the actual winding may be of some other material, such as aluminum. These losses vary with the square of the load. The losses also vary with the absolute temperature of the windings. For comparative purposes, load loss values are given at a reference load and at a reference winding temperature. It is important that these reference values be stated whenever loss values are given.

The losses in load tap changing (LTC) transformers vary with the LTC position. In addition, at any given position, the losses may vary with different configurations of LTC equipment, such as tap winding location, the presence of series transformers, preventive autotransformers, etc. The user should consider these variations when comparing two or more offerings.

For an ODAF, OFAF, ODWF or OFWF rated transformer, the losses are measured at that rating, or other agreed upon ratings [B4].

Any rating may be used to evaluate load losses (even one that may not be shown on the nameplate), so long as the manufacturer knows in advance, for optimizing the design and the test results are appropriately shown on the test report.

NOTE—The rating upon which the load losses are based usually refers to the self-cooled rating of the transformer (for those transformers that have a self-cooled rating), based on cooling class and temperature rise, and not to the extended ratings available with auxiliary cooling. For example, 12/16/20 MVA transformers having a self-cooled rating of 12 MVA usually have load losses tested at 12 MVA. When carrying 20 MVA, the load losses would be approximately 2.78, i.e., $(20/12)^2$ times the tested losses. In addition, the extended loading would call for fans and pumps to be running, which require additional power as listed in 3.6.4.[3]

3.6.4 Auxiliary losses (AL)

Auxiliary losses are losses that account for the watts used when auxiliary cooling equipment (fans and/or pumps) is applied. Typically this occurs on power transformers. Auxiliary losses are dependent on hours of operation and the power consumed during operation of these devices.

If two or more separate stages of cooling are used, these stages should be expressed in separate parts, auxiliary loss of stage 1 cooling (AL1), auxiliary loss of stage 2 cooling (AL2), etc., because the individual stages will be used for different amounts of time. The number of hours per year for each stage of cooling, hours of operation for stage 1 cooling per year (AHPY1), hours of operation for stage 2 cooling per year (AHPY2), etc., will need to be estimated in order to calculate a value for the energy for each stage. It should be kept in mind that generally stage 1 cooling is also running whenever stage 2 is on.

NOTE 1—The three loss values NL, LL, and AL are normally stated by the manufacturer with its bid, and later determined by actual tests.

NOTE 2—For power transformers used in high-voltage direct current (HVDC) converter stations, additional considerations are necessary for losses incurred by harmonic currents. These harmonic losses are not discussed in this guide.

3.6.5 Shunt reactors

A shunt reactor acts as a constant load at a given voltage. Its total loss cost evaluation (even though consisting mainly of I^2R losses) is calculated using only the no load loss or (A factor). Its losses increase as the impressed voltage increases.

3.6.6 Series reactors

A series reactor experiences a varying load. Because it does not have a no-load loss, its total power loss cost evaluation is calculated using only the load loss (or B factor). Its losses increase as the load increases.

[3]Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

3.7 Cost parameters

3.7.1 General

Because avoided costs are used in the evaluation of different demand-side and conservation alternatives, they can be used in the life-cycle TOC evaluations of transformers, if applied correctly. As described in 3.2, a component of TOC is the cost to the utility to supply transformer no-load and load losses, commonly referred to as the A and B factors. These transformer losses represent additional (incremental) load that the utility serves over the life of the transformer. If the utility's avoided costs reflect its long-range incremental costs taken over the transformer's economic life, they can be used to determine the system capacity and energy costs of the transformer no-load and load losses. That is, the avoided cost of energy can be used to determine the cost of system capacity.

Many utilities have already determined their avoided costs of capacity and energy. Assuming that those values reflect the continuing economic impact over the transformer's life, they should be used directly in the loss evaluation process. On the other hand, the following information provides insight into the avoided cost process.

Ideally, avoided costs of energy and generating capacity that are used in evaluating transformers should be determined on a long-range incremental cost basis, using a generation production costing and expansion planning computer program. Using such a program is an accurate method of determining the long-range incremental costs, since the program models costs and operational factors which influence long-range incremental costs. These factors include the utility load characteristics, projected peak loads (demand), existing and future generation capability and availability, generation maintenance, generation reliability, costs associated with construction of new generation plants, current and projected fuel prices, short-range purchase/sale contracts and long-range purchase/sale contracts. The generation expansion should include a planning reserve margin sufficient to maintain system reliability at a high level based on objective criteria. For example, such criteria may be power pool requirements or reliability criteria based on generating unit contingencies. Reserve margins have historically ranged between 15% and 30%.

Two simulations should be performed to determine the avoided costs of system capacity and energy. The first simulation, a base-case, should model the utility as accurately as possible with regard to present and future system characteristics. The second simulation, a change-case, uses the base-case model and data, but with the total utility load adjusted (preferably decremented) some amount. The decrement in load in the change-case should be an approximation based on the amount of load reduction that a utility forecasts due to all of its conservation and demand-side management programs. This simulation permits a quantification of all savings that the utility will likely experience if it implements all of its selected demand-side and conservation initiatives.

The values given in 3.7.2 to 3.7.5 are from publicly available information on wholesale electricity prices, transformer costs, and other dollar values. The numbers are provided for illustrative purposes only. Actual price (or cost) will vary by time and location. Each user of this guide should determine the price or cost values that it believes appropriate for making loss evaluations.

3.7.2 Avoided cost of system capacity (SC)

The avoided cost of system capacity consists of three components: avoided cost of generation capacity, the avoided cost of transmission capacity, and the avoided cost of distribution capacity.

$$SC = GC + TC + DC \tag{6}$$

where

SC is the avoided cost of system capacity, per kW-year
GC is the avoided cost of generation capacity, per kW-year
TC is the avoided cost of transmission capacity, per kW-year
DC is the avoided cost of distribution capacity, per kW-year

The evaluator shall understand where in the system the transformer is being connected to determine the impact on system capacity. A unit transformer (UT) would have no impact to transmission or distribution capacity while a distribution transformer will impact all three components of system capacity costs.

3.7.3 Avoided cost of generation capacity (GC)

As an example, if we consider a utility with a peak load of 10 000 MW that can reduce load by 5%, or 500 MW through conservation and demand side management initiatives, its generation expansion plans can be shifted in time as demonstrated in Table 1.

Table 1—Impact of load reduction on generation expansion plan

Year	Base case installed date (MW)			Alternative case installed date (MW)		
	Gas turbine	Combined cycle	Coal steam	Gas turbine	Combine cycle	Coal steam
2012	150	—	—	—	—	—
2014	—	300	—	150	—	—
2015	—	—	—	—	300	—
2017	—	—	500	—	—	—
2019	—	—	—	—	—	500
2020	300	—	—	—	—	—
2022	—	—	—	300	—	—
2023	—	600	—	—	—	—
2025	—	—	—	—	600	—

To determine the capitalized value of the avoided cost of generation capacity, the difference in the present worth of the two streams of carrying charge is calculated in Equation (7), Equation (8), and Equation (9).

The present worth cost for gas turbine is given by Equation (7):

$$PW = GT \times MW \times 10^3 \times (1 + ESC)^{N+1} \times PVF^N \times FCR \times PWF^{25-N} \tag{7}$$

The present worth cost for combined cycle is given by Equation (8):

$$PW = CC \times MW \times 10^3 \times (1 + ESC)^{N+1} \times PVF^N \times FCR \times PWF^{25-N} \tag{8}$$

The present worth cost for coal steam is given by Equation (9):

$$PW = CS \times MW \times 10^3 \times (1 + ESC)^{N+1} \times PVF^N \times FCR \times PWF^{25-N} \tag{9}$$

where

PW is the present worth ($), in this example is up to 2012
GT is the gas turbine cost ($/kW)
CC is the combined cycle cost ($/kW)
CS is the coal steam cost ($/kW)
MW are the megawatts installed
ESC is the escalation (%)
N $N1-N2$
$N1$ is the year installed
$N2$ is 2012 in this example (present worth)

PVF is the present value factor
FCR is the fixed charge rate (%)
PWF is the present worth factor

For simplicity, the evaluation is carried out over a 25-year period, during which the carrying charges for each case are computed to present worth in 2012. The example assumes a fixed charge rate of 17%, a cost of capital (interest rate) of 11%, and a general inflation rate of 4%. The price $/kW is based on the EIA's *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* [B11]. For the example:

GT $973.00/kW
CC $917.00/kW
CS $3,246.00/kW
FCR 17%
i 11%
ESC 4%

The values of capital recovery factor, present value factor, and present worth factor as a function of *N* (for the cost of capital equal to 11%) is calculated from the formula in Table A.1. The result is given in Table 2.

Table 2—Values of capital recovery factor, present value factor, and present worth factor as a function of *N* (the cost of capital equal to 11%)

Year	CRF	PWF	PVF
1	1.110000000	0.900900901	0.900900901
2	0.583933649	1.712523334	0.811622433
3	0.409213070	2.443714715	0.731191381
4	0.322326352	3.102445690	0.658730974
5	0.270570310	3.695897018	0.593451328
6	0.236376564	4.230537854	0.534640836
7	0.212215269	4.712196265	0.481658411
8	0.194321054	5.146122761	0.433926496
9	0.180601664	5.537047532	0.390924771
10	0.169801427	5.889232011	0.352184479
11	0.161121007	6.206515325	0.317283314
12	0.154027286	6.492356149	0.285840824
13	0.148150993	6.749870404	0.257514256
14	0.143228202	6.981865229	0.231994825
15	0.139065240	7.190869576	0.209004347
16	0.135516747	7.379161780	0.188292204
17	0.132471485	7.548794396	0.169632616
18	0.129842870	7.701616573	0.152822177
19	0.127562504	7.839294210	0.137677637
20	0.125575637	7.963328117	0.124033907
21	0.123837930	8.075070376	0.111742259
22	0.122313101	8.175739077	0.100668701
23	0.120971182	8.266431601	0.090692524
24	0.119787211	8.348136578	0.081704976
25	0.118740242	8.421744665	0.073608087

For the base case, a 150 MW gas turbine is installed in 2012. Its present worth cost is as follows:

$$N = 2012 - 2012 = 0$$

$$PW = GT \times MW \times 10^3 \times (1 + ESC)^{(N+1)} \times PVF^N \times FCR \times PWF^{(25-N)} \tag{10}$$

$$PW = 973 \times 150 \times 10^3 \times (1 + 0.04)^{(0+1)} \times 0.17 \times 8.421744665 = \$217,314,362.46 \tag{11}$$

A 300 MW combined cycle plant is installed in 2014. Its present worth cost is as follows:

$$N = 2014 - 2012 = 2 \tag{12}$$

$$PW = CC \times MW \times 10^3 \times (1 + ESC)^{(2+1)} \times PVF^2 \times FCR \times PWF^{(25-2)} \tag{13}$$

$$PW = 917 \times 300 \times 10^3 \times (1 + 0.04)^3 \times 0.811622433 \times 0.17 \times 8.266431601 = \$352,948,750.47 \tag{14}$$

Table 3 shows the total result of the base case and change case for this particular example.

Table 3—Total result of the base case and change case

Present worth cost base case		**Present worth cost change case**	
Gas turbine (2012_150MW)	**$217,314,362.46**	**Gas turbine (2014_150MW)**	**$187,251,436.32**
Combine cycle (2014_300MW)	$352,948,750.47	Combine cycle (2015_300MW)	$327,062,653.14
Coal steam (2017_500MW)	$1,649,860,380.69	Coal steam (2019_500MW)	$1,400,732,474.65
Gas turbine (2020_300MW)	$231,353,906.21	Gas turbine (2022_300MW)	$193,464,538.90
Combine cycle (2023_600MW)	$331,732,692.56	Combine cycle (2025_600MW)	$270,794,518.59
Total	$2,783,210,092.39	Total	$2,379,305,621.61

The process is continued for the remaining installations of the base case, yielding a total present worth of $2,783,210,092.39. Again, the process is carried out for the installations in the change case, yielding a total present worth of $2,379,305,621.61.

The present worth difference between two cases is $403,904,470.79, which represents the avoided cost. Because the process saved 500 MW, the cost per megawatt is $807,808.94 or $807.809/kW. To place this on a capitalized basis, the value is multiplied by the capital recovery factor for 25 years, and divided by the fixed charge rate:

$$\text{Capitalized Basis} = (\$807.809 \times CRF^{25}) / FCR \tag{15}$$

$$\text{Capitalized Basis} = (\$807.809 \times 0.118740242) / 0.17 = \$564.32 \tag{16}$$

Admittedly, the calculations are limited to a fixed period (in this case, 25 years; other durations may be deemed appropriate, for example 30 years for transmission assets), and the carrying charges are calculated only to that limit. Nevertheless, the process is reasonable and allows for a justifiable avoided cost of generation capacity.

Figure 1 and Figure 2 show illustrations of the generation expansion planning using reserve margin and the effect of load decrement on generation expansion plan.

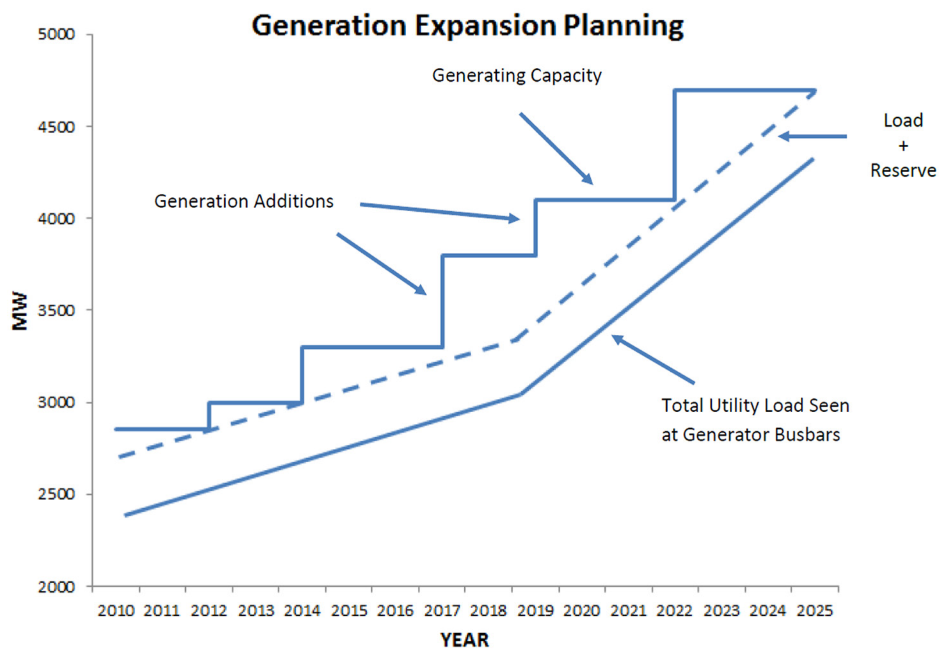

Figure 1—Generation expansion planning using reserve margin

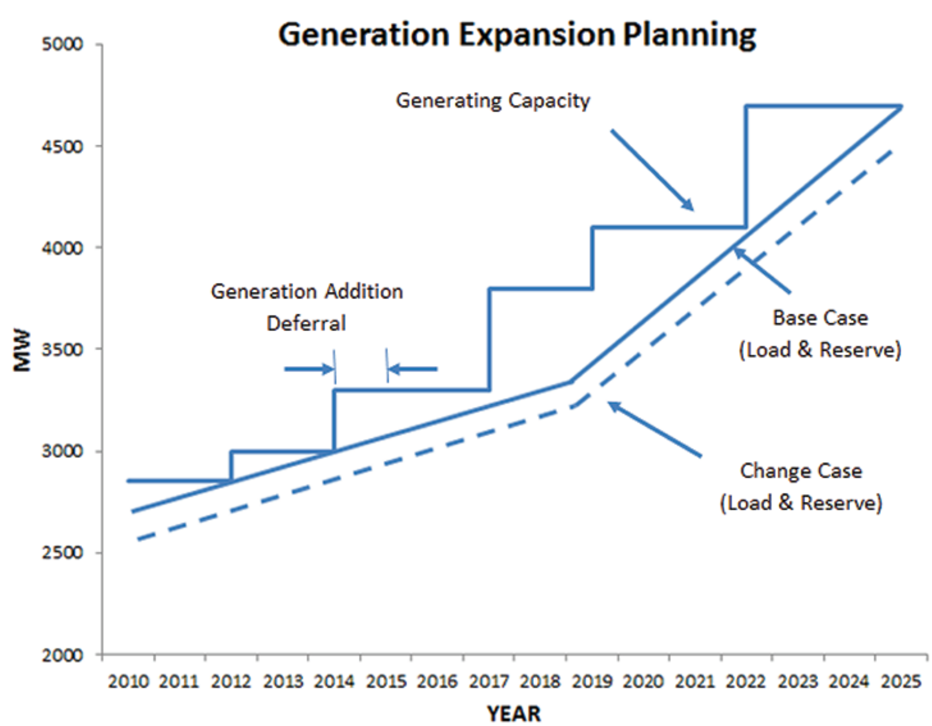

Figure 2—Effect of load decrement on generation expansion planning

3.7.4 Avoided costs of transmission (TC) and distribution capacity (DC)

To find the avoided cost of transmission and distribution capacity, it is necessary to find the utility specific cost of expansion. It is suggested that one gets cost for a new distribution line and substation and determine the cost and capacity using this information. This will give the dollar-per-kilowatt rate for the avoided cost of distribution capacity. The same procedure may be used to determine the cost of transmission capacity to determine dollar-per-kilowatt rate for the avoided cost of transmission capacity. Utilities typically have an estimated cost for new lines and substations in their planning group. They may also have what those additions would add to the capacity of the system. Once this value in today's cost is determined, the present worth method can be used to get the value for the life of the equipment using Equation (17) and Equation (18):

$$TC = CRF \times \text{Avoided First Year Cost} \times \frac{1-\left(\frac{1+ESC}{1+i}\right)^N}{i-ESC} \tag{17}$$

$$DC = CRF \times \text{Avoided First Year Cost} \times \frac{1-\left(\frac{1+ESC}{1+i}\right)^N}{i-ESC} \tag{18}$$

where

TC	is the avoided cost of transmission, per kW-year
DC	is the avoided cost of distribution capacity, per kW-year
ESC	is the escalation (%)
i	is the interest rate (%)
CRF	is the capital recovery factor
N	is the expected life (years)

Terms are the same as those in the avoided cost of generation other than N is the expected life of the transformer.

3.7.5 Avoided cost of energy (EC)

The avoided cost of energy is predominantly a fuel component, with a smaller variable Operations and Maintenance (O&M) component. It is the average incremental cost (avoided cost), not the average energy cost, which should be used for EC in the transformer owning cost equations. The procedure for calculating avoided costs using a base-case and change-case should also be used to calculate the avoided cost of energy. A similar detailed example for calculating the avoided cost of capacity was shown in 3.7.2. An example of how to determine the levelized avoided cost of energy can be found in A.1.5. It should also be recognized that it is necessary to estimate the avoided costs over the projected life of the equipment. To ignore the energy costs past some point in time, which is less than the equipment life, is to assign zero value to the cost of energy, which is inaccurate.

3.8 Load parameters

3.8.1 Levelized annual peak load (PL)

The levelized annual peak load seen by the transformer is equivalent to the function of an initial peak load with an estimated load growth rate and a maximum allowable load before change-out is required [see Equation (19)]. Figure 3 is a graphical display of the definition.

Note that the change-out may not be required depending on utility specific loading practices and the rate of projected load growth. This might manifest itself as a change in Figure 3 to 50% of the peak load after an anticipated period (perhaps as short as 5–10 years), which would be the result of a substation expansion or a transfer of load from the substation transformer to another transformer, or another station as area load grows.

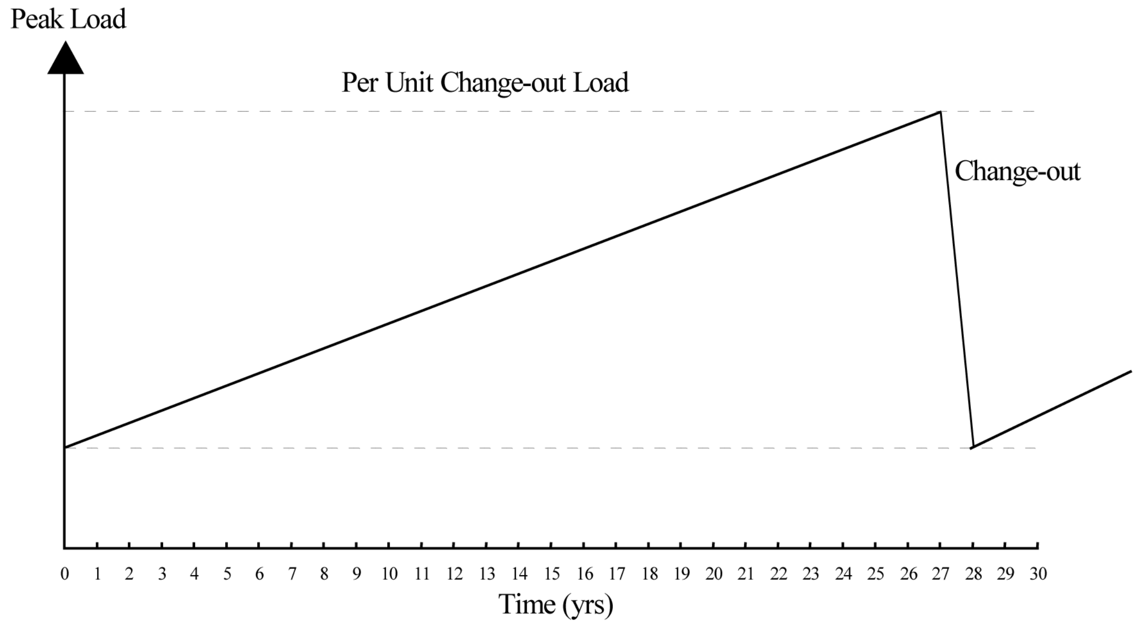

Figure 3—Transformer annual peak load

Although the concept of load loss evaluation shall consider the expected load growth to be experienced by the transformer, the load loss calculation considers the square of the load because losses accumulate as a squared function. For that reason, the following expression determines the square of the equivalent annual peak load, so it can be used directly in the loss evaluation equations. It should be noted that the levelizing function is directed not at the growing load per se, but rather at the economic contribution of load growth to the cost of load losses.

To calculate (peak load)^2, data is required on the following:

— The initial transformer load in per unit of nameplate rating

— The annual peak load growth experienced by the transformer in per unit and

— The number of years required for the transformer to attain its maximum load level

The levelized equivalent annual (peak load)^2 is shown in Equation (19):

$$PL^2 = \left[\sum_{j=1}^{n}\left(b(1+g)^{j-1}\right)^2 \times PVF_i^j + \sum_{j=n+1}^{N}\left(b(1+g)^{j-n-1}\right)^2 \times PVF_i^j\right] \times CRF_i^N \qquad (19)$$

where

N	is the transformer life (years)
n	is time to reach change-out load (years)
g	is the peak load growth rate (%)
b	initial transformer loading (%)
i	is the minimum acceptable return
CRF	is the capital recovery factor

As an example:

N	30 years
n	27 years
g	2.0%
b	90%
i	9%
CRF	0.09734

Then $PL^2 = 1.1574$.

A computer spreadsheet can be utilized to perform this calculation as shown in the Table 4.

Table 4—Example calculation levelized annual peak load

Year j	Per-unit nameplate load in year j	Per-unit nameplate load squared in year j	PVF (i = 9%)	Present value
1	0.900	0.81	0.91743	0.74312
2	0.918	0.84	0.84168	0.70930
3	0.936	0.88	0.77218	0.67703
4	0.955	0.91	0.70843	0.64622
5	0.974	0.95	0.64993	0.61681
6	0.994	0.99	0.59627	0.58875
7	1.014	1.03	0.54703	0.56196
8	1.034	1.07	0.50187	0.53638
9	1.054	1.11	0.46043	0.51198
10	1.076	1.16	0.42241	0.48868
11	1.097	1.20	0.38753	0.46644
12	1.119	1.25	0.35553	0.44522
13	1.141	1.30	0.32618	0.42496
14	1.164	1.36	0.29925	0.40562
15	1.188	1.41	0.27454	0.38716
16	1.211	1.47	0.25187	0.36954
17	1.236	1.53	0.23107	0.35273
18	1.260	1.59	0.21199	0.33668
19	1.283	1.65	0.19449	0.32136
20	1.311	1.72	0.17843	0.30673
21	1.337	1.79	0.16370	0.29278
22	1.364	1.86	0.15018	0.27945
23	1.391	1.94	0.13778	0.26674
24	1.419	2.01	0.12640	0.25460
25	1.448	2.10	0.11597	0.24301
26	1.477	2.18	0.10639	0.23196
27	1.506	2.27	0.09761	0.22140
28	0.900	0.81	0.08955	0.07253

Table continues

Table 4—Example calculation levelized annual peak load *(continued)*

Year j	Per-unit nameplate load in year j	Per-unit nameplate load squared in year j	PVF (i = 9%)	Present value
29	0.918	0.84	0.08215	0.06923
30	0.936	0.88	0.07537	0.06608
			Sum of the present worth values:	11.89

$$PL^2 = (\text{Total Present Value}) \times (CRF_{9\%}) = 11.89 \times 0.09734 = 1.1574 \quad (20)$$

3.8.2 Transformer loss factor (LSF)

Because a transformer's loads cycle between some maximum and minimum values, the load losses, which vary as the square of the load, will also cycle between some peak and minimum values. The loss factor, which is the ratio of the average load loss to the peak load loss, should be determined from the transformer's load profile, if it is known. The square of each load magnitude multiplied by the time at that load can be summed and divided by the square of the peak load.

For example, the typical daily residential load profile is shown in Figure 4.

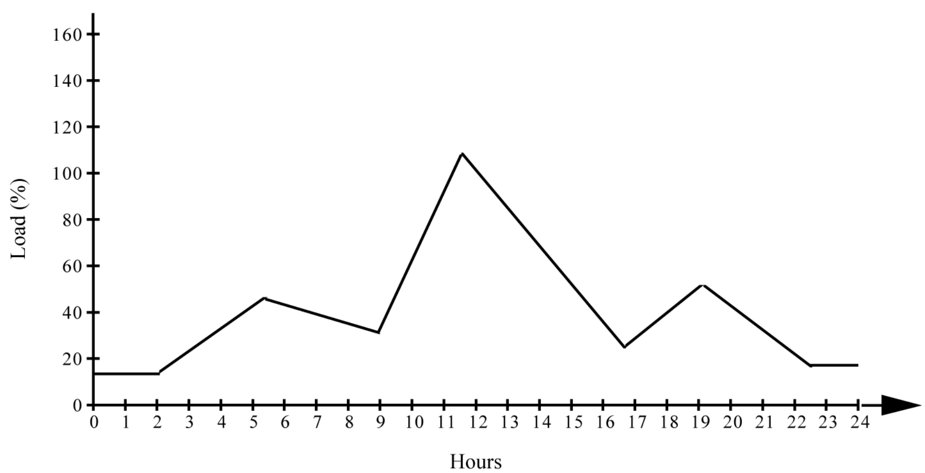

Figure 4—Typical residential profile

The Figure 4 hourly load profile can be expressed as shown in Figure 5.

The load profile in Figure 5 is converted to a loss factor as shown in Equation (21).

$$\text{Loss Factor} = \frac{\left[\dfrac{1.0^2 \times 1 + 0.7^2 \times 4 + 0.3^2 \times 16 + 0.1^2 \times 3}{24}\right]}{1.0^2} = 0.185 \quad (21)$$

This example describes the loss factor for a 24-hour period. For loss evaluation, the annual loss factor should be determined.

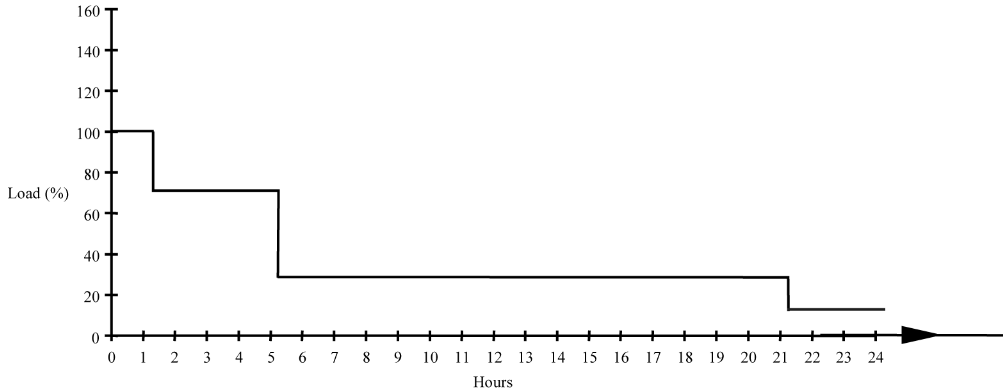

Figure 5—Equivalent hourly load profile

For residential loads, the load profile could be determined by measurement over time, but this could prove to be cumbersome and time consuming. If the transformer's load factor were known, which is the ratio of the average load over a period of time to the peak load during that time, the loss factor is within the limits of the load factor and the square of the load factor. An empirical relationship for loss factor and load factor for residential transformers is as follows:

$$LSF = 0.15 \times LF + 0.85 \times LF^2 \tag{22}$$

where

LSF is the loss factor
LF is the load factor

This empirical relationship holds true for substation transformers that serve similar types of loads that are a mix of residential commercial and small industrial. However, industrial loads and high density commercial loads follow a different loss factor.

The load factor can be determined by measurement, or it can readily be determined from load energy consumption, if peak load through the transformer is known, or reasonably assumed. Billing records will determine the energy consumed by the transformer's load for a given period of time. Those kilowatt hours, divided by the time period, will yield the average load. The average load divided by the peak load results in the load factor.

The load factor and loss factor are primarily influenced by the shape of the load curve, and peripherally by the size of the transformer and its per unit loading. A transformer that is loaded continuously to only a fraction of its nameplate load will result in a load factor and loss factor of 1.0.

The loss factors for residential distribution transformers can be expected to vary between limits of 0.05 to 0.20. This variation comes primarily from the number of customers served by the transformer which then relates to transformer size. Energy consumption by the total load can serve to verify this.

For transformers serving a load with a more predictable load pattern such as a commercial load, the loss factor should be determined by calculation from the load profile, and not by the previously described empirical relationship.

3.8.3 Peak responsibility factor (RF)

The peak responsibility factor defines the relationship between the transformer peak load and the transformer load at time of system peak load as shown in Figure 6. The cost of system capacity is multiplied by the responsibility factor in the B-factor equation, which essentially reduces the system capacity requirements for load losses since the peak losses on the distribution transformer do not necessarily occur at the time of system peak.

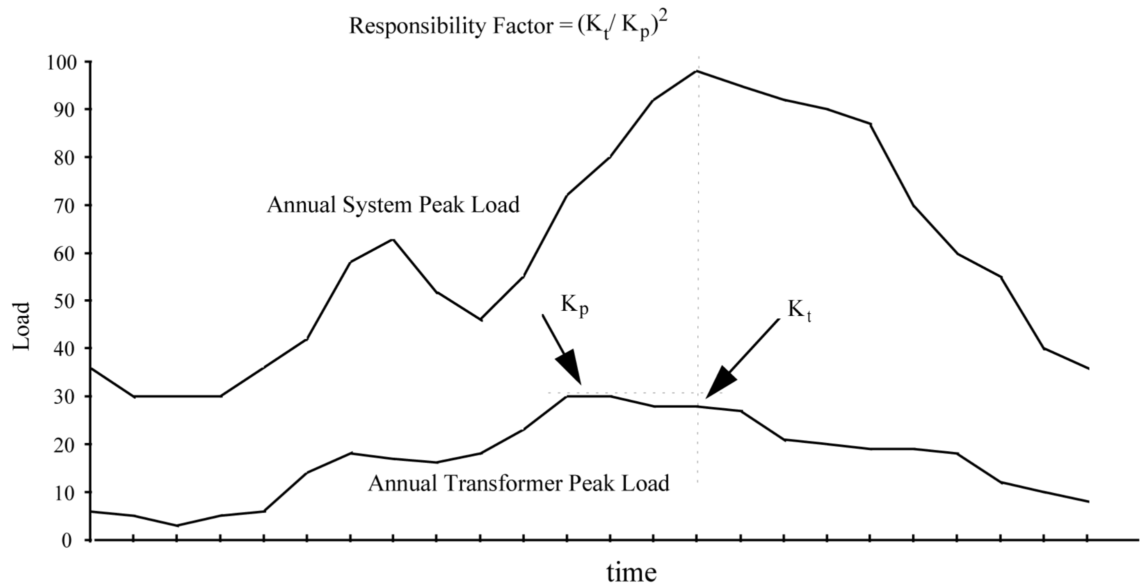

Figure 6—Peak responsibility factor

The peak responsibility factor is expressed as the square of the ratio of the transformer load at the time of system peak load, K_t, to the transformer peak load, K_p.

The peak responsibility factor can be determined as follows in Equation (23):

$$RF = \left(K_t / K_p\right)^2 \tag{23}$$

where

K_t transformer load at the time of system peak load
K_p transformer peak load

Lower values may exist in some cases but typical values for responsibility factor are as follow:

— 0.6–1.0 for urban

— 0.8–1.0 for rural

For example, given the transformer load at time of system peak is 18.4 kW and the peak transformer load is 25 kW:

$$RF = \left(18.4 / 25\right)^2 = 0.54 \tag{24}$$

3.8.4 Loss multiplier (LM)

In order to establish the overall impact of one unit of transformer loss to the entire system, it should be recognized that the unit of loss shall be supplied from generation through the transmission and distribution systems. In the process, additional losses are incurred because of the resistances of the bulk supply transformer(s), transmission lines, distribution substation transformers, and distribution primaries. To the generator bus, therefore, a unit of transformer loss becomes incrementally larger because of the system loss-on-loss effect. The incremental increase is stated in per-unit and is a function of the overall system.

The actual per-unit multiplier is system specific, but a 0.1 pu value is a reasonable estimate. Thus, a 1.0 pu distribution transformer loss could appear as a 1.1 pu demand at the generator bus. Once the avoided (incremental) cost of losses has been established in $/watt, the transformer TOC can be evaluated. This can best be accommodated by modifying the actual transformer loss upward to a level that incorporates system loss. For example, a transformer with 100 W of core loss should be evaluated with 110 W, assuming a system loss on loss multiplier of 1.1 pu. The 0.1 pu represents the losses for entire generation, transmission, and distribution systems. For loss values at other points in the system, the multiplier will be somewhat less than 1.1 pu. This will result in A and B factors that are unique to the point in the system at which the transformer is being evaluated.

3.9 Example

These numbers are provided for illustrative purposes only. Actual price (or cost) will vary by time and location. Each user of this guide should determine the price, or cost values, that they believe is appropriate for making loss evaluations. Table 5, Table 6, and Table 7 show the parameters used in this example.

Table 5—Transformer parameters

	Units	Symbol	Transformer #1	Transformer #2
Bid price	$	P	650	640
No-load losses (core)	W	NL	55	65
Load losses	W	LL	300	320
Hours per year energized	h	HPY	8760	8760

Table 6—Cost factors (levelized values shown)

	Units	Symbol	Transformer #1	Transformer #2
Avoided cost of system capacity	$/kW-yr	SC	71.4	71.4
Avoided cost of generation capacity	$/kW-yr	GC	54.4	54.4
Avoided cost of t & d capacity	$/kW-yr	TC +DC	17.0	17.0
Avoided cost of energy	¢/kWh-yr	EC	8.43	8.43
Fixed charge rate	%	FCR	17.0	17.0

Table 7—Transformer load characteristics

	Units	Symbol	Transformer #1	Transformer #2
Levelized equivalent annual peak load^2	—	PL^2	1.1574	1.1574
Transformer loss factor	pu	LSF	0.15	0.15
Peak responsibility factor	pu	RF	0.9	0.9
Loss multiplier	pu	LM	1.1	1.1

The calculation of the TOC for transformer 1 is shown in Equation (25) through Equation (29).

The equivalent first cost of no-load losses ($/watt) A for transformer 1 is determined using Equation (2):

$$A = \frac{71.4 + 0.0843 \times 8760}{0.17 \times 1000} \times 1.1 = \$\ 5.24\ /\ \mathrm{W} \tag{25}$$

Cost of no-load loss (EFC) is determined as follows:

$$EFC_{NLL} = A \times NLL = 5.24\ (\$\ /\ \mathrm{watt}) \times 55\ (\mathrm{watts}) = \$288 \tag{26}$$

Equivalent first cost of load losses ($/watt) B is determined as follows:

$$B \ = \ \frac{[\ (SC \times RF) + \ (EC \times \ LSF \times HPY)\ ] \times (PL)^2}{FCR \times 1000} \times LM \tag{27}$$

$$B = \frac{[(71.4 \times 0.9) + (0.0843 \times 0.15 \times 8760)] \times (1.1574)}{0.17 \times 1000} \times 1.1 = \$1.31 / \mathrm{W} \tag{28}$$

Cost of load loss (EFC) is determined as follows:

$$EFC_{LL} = B \times LL = 1.31\ (\$\ /\ \mathrm{watt}) \times 300\ (\mathrm{watts}) = \$393 \tag{29}$$

The EFC for transformer 2 will be calculated in the same method as transformer 1. The total ownership cost of both transformers is then:

$$TOC_{EFC} = P + EFC_{NLL} + EPC_{LL} \tag{30}$$

$$TOC_{\mathrm{Transformer1}} = \$650 + \$288 + \$393 = \$1331 \tag{31}$$

$$TOC_{\mathrm{Transformer2}} = \$640 + \$340 + \$419 = \$1399 \tag{32}$$

Comparing the results of Equation (31) and Equation (32) in this example determines that the lowest cost purchase price does not necessarily yield the lowest TOC over the life of the transformer.

4. Transformer loss evaluation for industrial and commercial entities and transmission only electric utilities

4.1 Introduction

Although most of today's documentation on loss evaluation reflects issues regarding the utility industry, there is a very large segment of transformer purchasers and users that are non-utility. Specifically, the industrial and commercial business segments also deal with transformer purchases. In some cases, particularly within the commercial sector, the utility may provide the transformer to serve the load, and efficiency levels become the responsibility of the utility, unless the transformer is metered on the primary. In other cases, the end user may bear the cost of the efficiency and should recognize its economic impact on the annual cost of operation.

In many respects, the impact of transformer efficiency on a commercial/industrial purchaser of power is reasonably straightforward. Such entities are metered for demand and energy consumption and will be billed for that consumption. There is no equivocation here. Every kilowatt of demand and every kilowatt hour of energy consumption, from both load and losses, is recorded and invoiced. Contrasted with the utility concerns over avoided capacity costs, incremental energy costs, issues regarding future cost projections, and externalities charges, the commercial or industrial consumer knows the relevant costs today and with rational discussions with its supplier, can establish reasonable future costs.

It seems reasonable, therefore, that the industrial and commercial consumers should be strong proponents of loss evaluation, given the understanding that they are paying for losses. This, with few exceptions, does not appear to be the case. The reasons for this tend to be among the following.

In an industrial installation, the electrical plant required to provide for a manufacturing process may be considered to have a relatively shorter life because of the nature of the process or its strategic importance to the business. Life-cycle costs may be considered less important.

The transformer purchase decision may be the responsibility of a contractor retained to complete the installation. The contractor may not be measured on the future operating costs.

Loss evaluation may not be understood well enough to recognize its impact on operating costs and the transformer purchases decision.

None of these factors negate the need for efficiency evaluation. Once the installation is energized, the power/energy consumption costs are paid. Transformers are available to provide the lowest owning/operating costs regardless of the owning period.

There is a very significant and perhaps often overlooked aspect of the nature of commercial or industrial load that should create a heightened awareness of transformer efficiency. The loads served tend to be of relatively high load factors. That is, they maintain their peak levels relatively constant over time, reducing to a low level only when the operation diminishes for a period of time. For those industrials that operate on a multi-shift basis, the transformer load can be quite constant over longer periods of time, with a resultant very high load factor. This type of load should place a greater emphasis on the magnitude of transformer load loss, because the energy consumed by the load loss, and its cost, can be considerably higher than that of the transformer core.

In many respects, the transformer's owning cost evaluation for an industrial or commercial consumer parallels that for an electric utility. That is, the relevant cost factors and system parameters are input quantities to the same equations. The term levelized fixed charge may not be familiar to those in industrial practice. However, because it is necessary to include the impacts of depreciation, taxes, and insurance in order to perform a valid loss evaluation, use of a levelized fixed charge, or a functional equivalent, is strongly recommended. It may be appropriate, then, under some circumstances, to depart from traditional utility evaluation practices and to establish an evaluation procedure for the industrial/commercial user. This procedure can provide for a differentiation among designs, such that a design choice that will reflect the customer's owning constraints can be made. One way of determining these costs is manifested in present valuing future operating costs.

Regardless of whether the user purchases its capacity and energy directly from a utility supplier, or if it supplies it from its own generation facilities, there is a cost associated with the process. As time goes on, those costs of providing service will continue, most likely in an escalating fashion, such that a significant impact on the equipment purchase decision should be felt. To purchase a transformer based solely on first price is to ignore these costs, which can prove to overwhelm the initial transformer price.

Assuming that the end user is billed for both capacity and energy, present worth spreadsheets can be established similar to what is described in A.2 of this guide. The spreadsheets establish the cumulative present worth of an escalating series, both for energy and capacity. Such spreadsheets can be established for both no-load and load loss, reflecting the impact of the other load loss parameters.

Although future cost escalation rates may not be totally apparent, discussions with utility suppliers, or reviews of fuel forecasts, can yield a reasonable sense of the proper escalation rate to employ. Short of that, a rational projection of costs incurred in the past can be applied, although forecasted information is much more acceptable.

A distribution-only utility faces the same evaluation considerations. In most cases, they are provided for (by contracting for power delivery) the demand and load components, covered in the previous clauses.

4.2 Example

Consider the evaluations of transformer no-load and load losses that are illustrated in the spreadsheets of Annex A. The pertinent considerations in determining present worth A and B factors for commercial and industrial consumers are as follows:

— Demand and energy costs are included in the process, with some escalation effects.

— The peak load on the transformer is more than likely close to nameplate and can be expected to remain at that level. Conversely, transformers that are initially loaded at a level somewhat less than nameplate should reflect some effective value of load growth in the evaluation.

— The responsibility factor in the load loss equation can be considered to be unity, unless the load profile of the transformer varies continuously over time. This can be a complication for transformers within an industrial plant.

— The loss factor should be determined from the transformer's load cycle, and not from empirical relationships.

The following example serves to illustrate the entire process for determining the present worth A and B factors for the commercial and industrial users. The example assumes a wide range of parametric variability and applies closed-form equations as described in the annexes. Obviously, year-by-year present worth spreadsheets can similarly be applied. The closed-form equations are used to demonstrate the efficacy of a quick, concise approach.

The following assumptions apply:

— Capacity: \$12.00/kW/month (escalating at 2% annually)

— Energy: \$0.03/kWh (escalating at 4% annually)

— Load: u (growing at 1% annually)

— Peak responsibility factor: 1.0

— Loss factor: 0.5

— Discount rate: 11%

— Evaluation period: 20 years

To determine the present worth A factor, the present worth of capacity and energy charges is calculated first. This is accomplished by using the equations for the uniform annual inflation series [i.e., annual cost × PW(IS); where PW(IS) is Equation (A.19) in Annex A].

For capacity:

$$(\$12 \times 12) \times \left[\frac{1 - \left(\dfrac{1.02}{1.11} \right)^{20}}{0.11 - 0.02} \right] = \$1305 / \text{kW} \tag{33}$$

For energy:

$$\$0.03\left[\frac{1-\left(\dfrac{1.04}{1.11}\right)^{20}}{0.11-0.04}\right] = \$0.3121/\text{kWh} \tag{34}$$

The A factor becomes:

$$A = \$1305 + (8760 \times \$0.3121) = \$1305 + \$2734 = \$4039\ /\ \text{kW} = \$4.04\ /\ \text{W} \tag{35}$$

To determine the B factor, Equation (A.37) is applied. Because present worth results are desired, the capital recovery factor is not applied as a multiplier (the indicated equations without the capital recovery factor yield present worth values.)

Because transformer load growth, capacity, and energy changes are all escalated, the closed-form equation is applied.

For capacity:

$$\frac{0.95^2}{1.11^{20}}\left[\frac{1.11^{20} - 1.01^{40} \times 1.02^{20}}{1.11 - 1.01^2 \times 1.02}\right] = 9.423 \tag{36}$$

For energy:

$$\frac{0.95^2}{1.11^{20}}\left[\frac{1.11^{20} - 1.01^{40} \times 1.04^{20}}{1.11 - 1.01^2 \times 1.04}\right] = 10.944 \tag{37}$$

The B factor becomes:

$$B = \$144 \times 9.423 \times 1.0 + \$0.03 \times 10.944 \times 0.5 \times 8760 = \$1356 + \$1438 = \$2794\ /\ \text{kW} = \$2.79\ /\ \text{W} \tag{38}$$

This example also serves to illustrate the significant impact that load losses can have on the transformer design.

The total owning cost equation becomes:

$$TOC = P + NLL \times \$4.04\ /\ \text{W} + LL \times \$2.79\ /\ \text{W} \tag{39}$$

Despite the need for loss evaluation in the commercial and industrial area, there are other considerations that are explored. For most commercial loads, the demand and energy charges as defined in this guide are applicable. The resultant costs of no-load and load loss can be used to determine the transformer design to be purchased.

Industrial applications provide a somewhat different perspective on the loss evaluation process. As opposed to the commercial load, for which a transformer can be singularly applied to provide the voltage required by the utilization devices, industrial load quite often requires at least two stages of voltage transformation. The utility may provide power at a transmission voltage that is stepped down at an industrial substation to a distribution voltage level. The industrial distribution system provides additional transformation to utilization voltage(s).

Although the loss evaluation methodology described in this guide can be applied to all transformers found within the industrial plant, it may be the case that those transformers located throughout the plant providing utilization voltage to the various processes are not specified by the use of loss evaluation constants (A and B factors). Clearly, the cost of no-load loss could easily be defined for all transformers because the cost of no-load loss relates directly to the demand and energy charges imposed by the supplier. The costs of load loss for the various transformers located throughout the plant could be different for the following reasons:

- The load cycles experienced by the transformers are application-specific. A transformer that supplies lighting load may have a load cycle different from a transformer supplying a motor drive.
- Per unit peak demands on the transformers can be different.
- The coincidence between the transformers' peak demands and the overall industrial load cycle can be different.
- The owning period for certain transformers may be determined by the processes they serve, and may be different. This can also impact the cost of no-load loss.
- It is also quite often the case that such transformers are purchased from an expediency basis rather than from a basis of specifying design constants, including efficiency.

4.3 Alternate methods for determining system investment (SC) for non-vertically integrated utilities and industrial users

Method 1, according to the U.S. Department of Agriculture RUS Bulletin 1724E-301 [B12]:

> *One method for determining the SC value involves adding the construction cost (dollars per kilowatt) of a recently completed or soon to be completed generating station to the cost of the transmission facilities (dollars per kilowatt) required to connect the transformer to the plant. If power is purchased rather than self-generated, the SC value can be determined by dividing the demand charge in dollars per kW per year by the fixed charge rate (FCR). Since there is more than one method of evaluating the SC value, the method that is judged to yield the most realistic results should be used.*

Method 2, separate calculations of Transmission Investment and Generation Investment can also be made. Sources are publically available from the U.S. Energy Information Agency (EIA) or the Department of Energy (DOE) for installed cost of various types of generation, including nuclear, gas turbine (GT), combined cycle combustion turbine (CCGT), wind turbine, solar power, and other renewable energy sources.

A summary report issued in 2015, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015 [B6], and a spreadsheet file of capital costs issued in 2013, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants [B11], are available on the U.S. EIA website.

The two values obtained for the same type of generation can thus be compared for sensitivity as well as for changes in cost over time due, possibly, to improvements in technology or economies of scale.

The FERC Form 1 [B1] is available on the website of the Federal Energy Regulatory Commission and contains information which, if properly analyzed, can provide results by Company. For example, the form "SALES FOR RESALE (Account 447)" on page 311 of Form 1 provides indication of Demand Charge by Customer for more than 14 classes of sale.

The annualized cost of System Investment and / or the other factors such as forecasted Rate of Inflation, Levelized Peak Loading, etc., are all estimates (forecasts). As long as all assumptions are applied the same to each manufacturer's proposed guaranteed losses, the result will be the same. Achieving a 'too efficient' transformer or a transformer that ends up with a higher total owning cost than estimated based on the assumptions is always possible. The only way to avoid paying too much for a transformer (too efficient) is to correctly predict the future cost of generation and the future cost of installed transmission. Sensitivity analysis can be performed prior to releasing the tender for bidding to determine what factors will influence the purchase decision and by how much. After sensitivity analysis is complete, the factors can be evaluated and changed depending on the certainty with which one can arrive at those factors.

There are three scenarios in which a non-vertically integrated utility may fall:

— A Generation Company (GENCO).

  The System Investment (SC) will only be GC described in 3.7.2. It will be the estimated cost of completion of the facility in which the transformer will be installed.

— A Transmission Company (TRANSCO) that simply provides transmission services with no generation or distribution.

  The SC for such a company is made up of only GC and TC described in 3.7.2.

  GC may be determined using the approach in scenario b).

  TC may be determined using the following approach:

  - Determine the estimated future cost of new transmission facilities and add the installed cost of existing transmission facilities (its own records).
  - Determine the annual load carried by the TRANSCO and add the estimated future load in kilowatt hours.
  - Divide the estimated capital value of the first step by the annual kilowatt hours in the second step to determine dollars per kilowatt hours in TC.

— A Distribution Company (DISCO) that owns neither generation nor transmission of any sort.

  The SC for such a company is made up of GC + TC + DC as described in 3.7.2

The combined cost of GC + TC can be determined in either method 1 or method 2 described in this subclause.

DC is determined from (its own records) the combined installed cost of all existing and future distribution to serve the existing and future load.

An industrial or other end user may apply the same approach to its owned facilities as the DISCO.

Annex A

(informative)

Formulas, tables, and figures

A.1 Basic economic formulas

A.1.1 General

Table A.1 provides a summary of basic time value of money formulas.

Table A.1—Summary of basic economic formulas

	Abbreviation	Given	Find	Formula
Compound-interest factor	CIF	P	F	$(1+i)^n$
Present value factor	PVF	F	P	$\frac{1}{(1+i)^n}$
Present worth of uniform series factor	PWF	R	P	$\frac{(1+i)^n-1}{i(1+i)^n}$
Capital recovery factor	CRF	P	R	$\frac{i(1+i)^n}{(1+i)^n-1}$
Compound-amount factor	CAF	R	F	$\frac{(1+i)^n-1}{i}$
Sinking-fund factor	SFF	F	R	$\frac{i}{(1+i)^n-1}$
Present worth of an inflation series	PW(IS)	R_a	P	$\left(\frac{1-[(1+a)/(1+i)]^n}{i-a}\right)$

[a]The variable list for equations in Table A.1 is as follows:

- P is the present spot cash equivalent
- F is the future spot cash equivalent
- R is the recurring annual cash stream
- n is the number of years
- i is the cost of capital (interest rate) (% per year)
- a is the inflation rate (% per year)

NOTE—The present worth of an inflation series is a factor in levelizing, as described in A.2.

A.1.2 Single-payment interest factors

A.1.2.1 Compoundlinterest factor (CIF)

Figure A.1 illustrates the concept of CIF, which is: given P dollars today, find the value, F dollars, n years in the future, given the annual interest rate of i%.

$$CIF = (1+i)^n \quad \text{(A.1)}$$

where

i	is the interest rate
n	is the time period

$$F = CIF \times P \tag{A.2}$$

where

CIF	is the compound interest factor
P	is the present value of an investment
F	is the future value of an investment

For example, when:

P	\$1000
i	7%
n	10 years

$$F = (1+0.07)^{10} \times 1000 = \$1967.15 \tag{A.3}$$

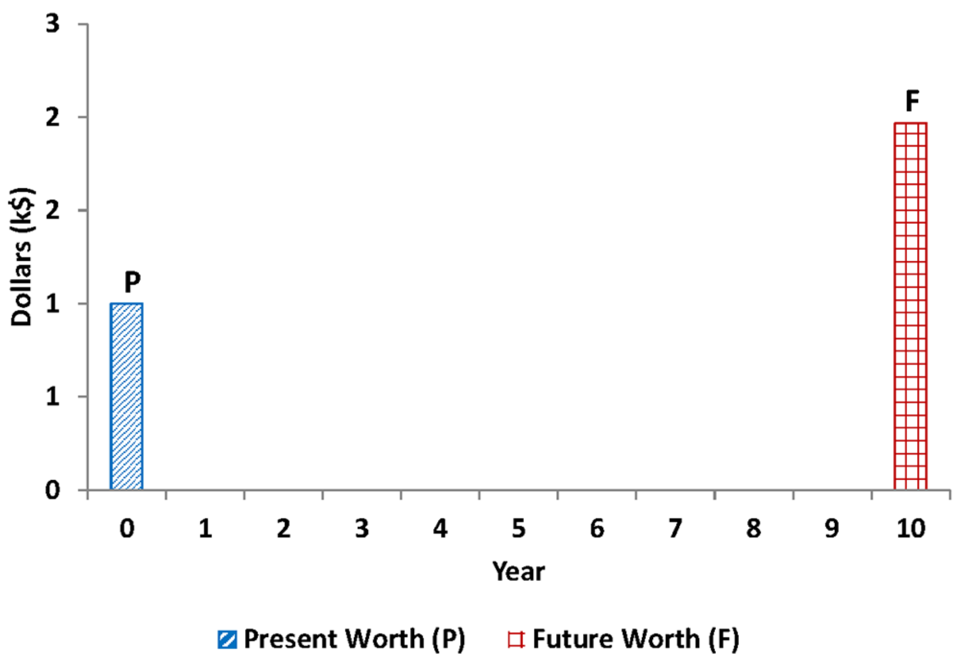

Figure A.1—Simple payment interest factors

A.1.2.2 Present-value factor (PVF)

Figure A.1 also illustrates the concept of PVF, which is: given F dollars n years in the future, find the value of P dollars today, given the annual interest rate of i%.

$$PVF = \frac{1}{(1+i)^n} \tag{A.4}$$

where

i is the interest rate
n is the time period

$$P = PVF \times F = (1/CIF) \times F \tag{A.5}$$

where

PVF is the present value factor
CIF is the compound interest factor
P is the present value of an investment
F is the future value of an investment

For example when:

F \$1967.15
i 7%
n 10 years

$$P = \frac{1}{(1+0.07)^{10}} \times \$1967.15 = 0.50835 \times \$1967.15 = \$1000.00 \tag{A.6}$$

A.1.3 Uniform series factors (USF)

A.1.3.1 Present worth of uniform series factor (PWF)

Figure A.2 illustrates the concept of USF, which is: given R dollars per year for n years, find the value of P dollars today, given the annual interest rate of i%.

$$PWF = \frac{(1+i)^n - 1}{i(1+i)^n} \tag{A.7}$$

where

i is the interest rate
n is the time period

$$P = PWF \times R \tag{A.8}$$

where

R is the annual investment
PWF is the present worth factor

For example when:

R \$1000.00
i 7%
n 10 years

$$P = \frac{(1+0.07)^{10} - 1}{0.07(1+0.07)^{10}} \times \$1000 = 7.02358 \times \$1000 = \$7023.58 \tag{A.9}$$

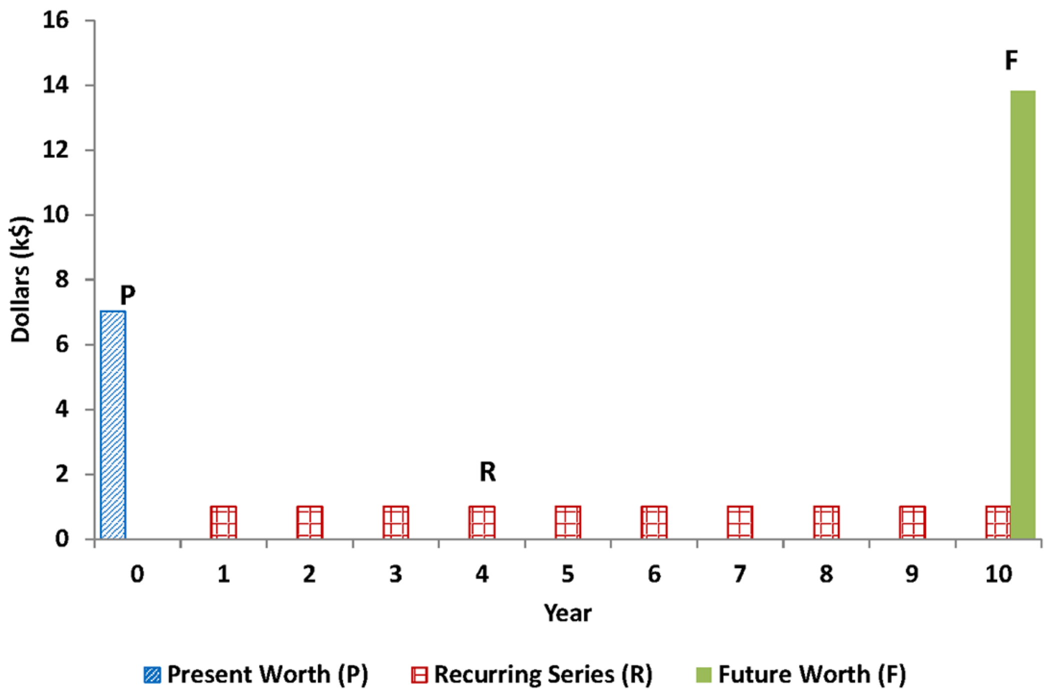

Figure A.2—Uniform series factors

A.1.4 Capital recovery factor (CRF)

A.1.4.1 General

Capital recovery factor which is: given P dollars today, convert into an annuity R for n years, given the annual interest rate of i%.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{A.10}$$

where

i is the interest rate
n is the time period

$$R = CRF \times P \tag{A.11}$$

where

P is the present value of an investment
CRF is the capital recovery factor

For example, when:

P $1000
i 7%
n 10 years

$$R = \frac{0.07(1+0.07)^{10}}{(1+0.07)^{10} - 1} \times \$1000 = 0.14237 \times \$1000 = \$142.37 \tag{A.12}$$

A.1.4.2 Compound amount factor (CAF)

Figure A.2 also illustrates the concept of CAF, which is: given R dollars per year for n years, find the future value of F dollars, given the annual interest rate of i%.

$$CAF = \frac{(1+i)^n - 1}{i} \tag{A.13}$$

where

- i is the interest rate
- n is the time period

$$F = CAF \times R = CIF \times PWF \times R \tag{A.14}$$

where

- R is the annual investment
- CAF is the compound amount factor
- CIF is the compound interest factor
- PWF is the present worth factor

For example, when:

- R \$1000.00
- i 7%
- n 10 years

$$F = \frac{(1+0.07)^{10} - 1}{0.07} \times \$1000 = 13.81644 \times \$1000 = \$13816.44 \tag{A.15}$$

A.1.4.3 Sinking fund factor (SFF)

Figure A.3 also illustrates the concept of SFF, which is: find the annual value of R dollars over n years that is equal to a future payment of F dollars, given the annual interest rate of i%.

$$SFF = \frac{i}{(1+i)^n - 1} \tag{A.16}$$

where

- i is the interest rate
- n is the time period

$$R = SFF \times F = 1 / CAF \times F \tag{A.17}$$

where

- F is the future value of an investment
- SFF is the sinking fund factor
- CAF is the compound amount factor

For example, when:

F	\$1000.00
i	7%
n	10 years

$$R = \frac{0.07}{(1+0.07)^{10} - 1} \times \$1000 = 0.07237 \times \$1000 = \$72.37 \tag{A.18}$$

Another way of viewing CRF is that it is equal to the discount rate plus the sinking-fund factor. That is, the CRF provides a return on the investment (i) plus the return of the investment (SFF). Figure A.3 illustrates these concepts of CRF.

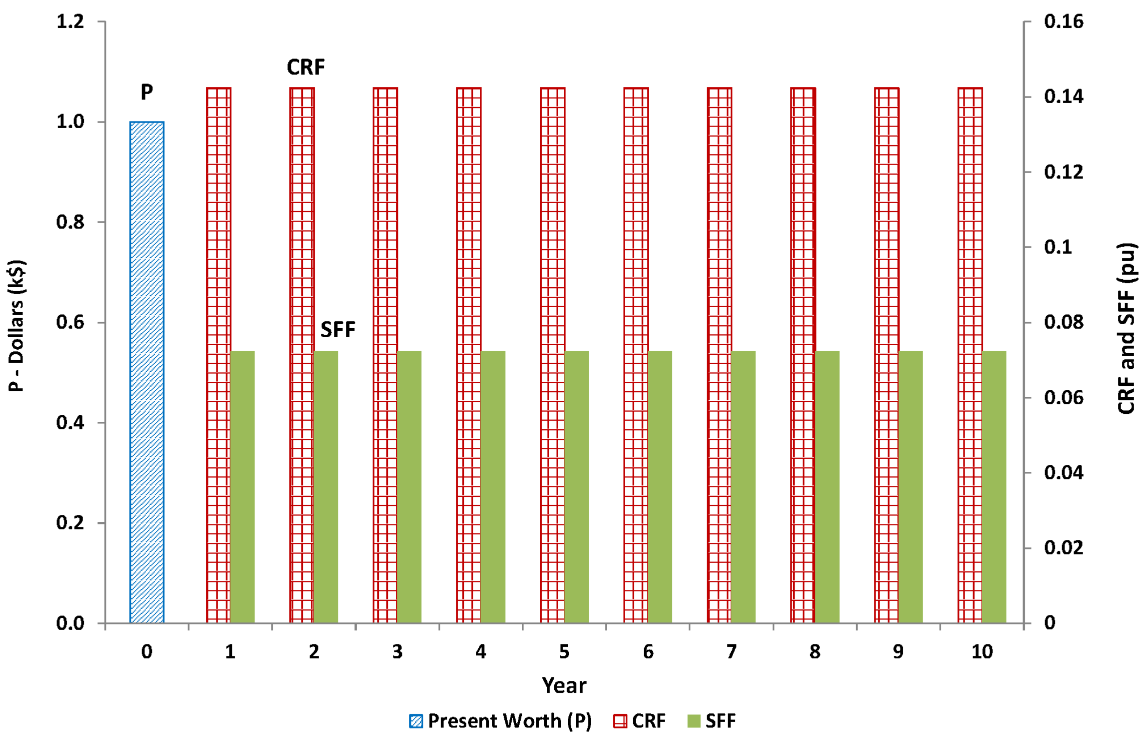

Figure A.3—Capital recovery factor

A.1.4.4 Uniform annual equivalent of an inflation series [PW(IS)]

A series of payments that increase in proportion to an inflation index is called a uniform annual inflation series. Figure A.4 illustrates this concept. Mathematically, this describes a geometric progression given by Equation (A.19):

$$PW(IS) = \frac{\left[1 - \left(\frac{1+a}{1+i}\right)^{n}\right]}{i-a} \tag{A.19}$$

where

i is the interest rate
n is the time period
a is the inflation

$$P = PW(IS) \times R \tag{A.20}$$

where

$PW(IS)$ is the present worth inflation series
R is the annual investment

For example, when:

R $1000
I 7%
a 4.5%
n 10 years

$$PW(IS) == \frac{\$\left[1-\left(\dfrac{1\ +\ 0.045}{1\ +\ 0.07}\right)^{10}\right]}{0.07-0.045} \times \$1000 = \ 8.422 \times \$1000 = \$8422 \tag{A.21}$$

Note that this evaluation process is fundamental to determining the levelized value of escalating costs, such as fuel cost.

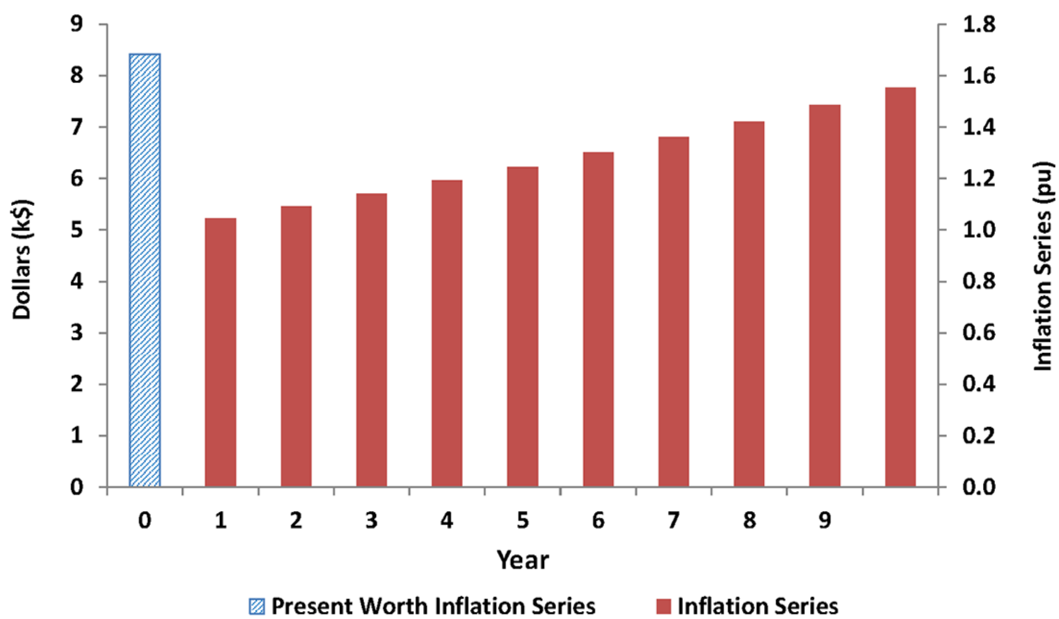

Figure A.4—Present worth of an inflation series

A.1.5 Levelizing

Levelizing is converting a varying stream of values to a uniform annual equivalent value over a given period of time. In terms of transformer economic evaluation, levelized values are used in the equivalent first cost and annual cost methods as inputs to the total owning cost formulas. In transformer loss evaluation, the terms that generally are levelized are the avoided cost of energy and the contribution of load growth, PL^2. The avoided cost of capacity (SC) is often a levelized value, although it is occasionally expressed as a fixed, unescalated magnitude. The method by which values are levelized is dependent upon the form in which the input data is presented.

For example, the avoided cost of energy for the current year is given as 5.0 ¢/kWh and is expected to increase at 4.5% per year. Using concepts discussed in A.1, the uniform levelizing value is:

$$\text{Levelized value} = \alpha \times PW(IS) \times CRF \tag{A.22}$$

where

α	is the value to be levelized
$PW(IS)$	is the present worth inflation series
CRF	is the capital recovery factor

The levelizing factor (LF) can be determined as follows:

$$LF = PW(IS) \times CRF \tag{A.23}$$

$$LF = \left[\frac{1 - \left(\dfrac{1+a}{1+i} \right)^n}{i - a} \right] x \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right] \tag{A.24}$$

where

i	is the interest rate
n	is the time period
a	is inflation

For example, if avoided cost of energy in the first year needs to be levelized, then:

α	5.0 ¢ /kWh
i	10%
a	4.5%
n	30 years
CRF	0.106

$$LF = \left[\frac{1 - \left(\dfrac{1+0.045}{1+0.1} \right)^{30}}{(0.1 - 0.045)} \right] \times \left[\frac{0.1(1+0.1)^{30}}{(1+0.1)^{30} - 1} \right] = 14.28 \tag{A.25}$$

$$\text{Levelized value} = 5.0\ ¢\ /\text{kWh x } 14.28 \times 0.106 = 7.57\ ¢\ /\text{kWh} = 0.0757\$\ /\text{kWh} \tag{A.26}$$

Avoided cost information may also be provided on a yearly basis. For example, the avoided cost of energy over the next 30 years for utility XYZ is shown in Table A.2.

Table A.2—Utility XYZ data for levelizing example

Year	Avoided cost of energy (¢ /kWh)
1	6.00
2	5.84
3	5.72
4	5.45
5	5.75
6	5.70
7	5.98
8	6.28
9	6.70
10	7.14
11	7.53
12	8.02
13	8.63
14	9.08
15	9.67
16	10.43
17	11.08
18	12.26
19	13.50
20	14.24
21	15.40
22	16.67
23	18.05
24	19.54
25	21.17
26	22.95
27	24.88
28	26.97
29	29.26
30	31.75

Note that avoided cost values may not necessarily be monotonically increasing due to factors such as generating unit dispatching variations due to new unit additions and/or retirements, load growth, and so forth.

$$\text{Levelized Avoided Cost} = \left(\sum_{j=1}^{N} E_j \times PV \underset{i}{\overset{j}{F}} \right) \times CR \underset{i}{\overset{N}{F}} \tag{A.27}$$

The use of a computer spreadsheet is often useful for values that change on an annual basis.

For example, given the following information for utility XYZ:

i	10%
n	30 years
CRF	0.106

Table A.3—Levelized avoided cost example

Year	Avoided cost of energy (¢ /kWh)	$PVF_{10\%}$	Present value of avoided cost (¢ /kWh)
1	6.00	0.9091	5.45
2	5.84	0.8264	4.83
3	5.72	0.7513	4.30
4	5.45	0.6830	3.72
5	5.75	0.6209	3.57
6	5.70	0.5645	3.22
7	5.98	0.5132	3.07
8	6.28	0.4665	2.93
9	6.70	0.4241	2.84
10	7.14	0.3855	2.75
11	7.53	0.3505	2.64
12	8.02	0.3186	2.56
13	8.63	0.2897	2.50
14	9.08	0.2633	2.39
15	9.67	0.2394	2.31
16	10.43	0.2176	2.27
17	11.08	0.1978	2.19
18	12.26	0.1799	2.21
19	13.50	0.1635	2.21
20	14.24	0.1486	2.12
21	15.40	0.1351	2.08
22	16.67	0.1228	2.05
23	18.05	0.1117	2.02
24	19.54	0.1015	1.98
25	21.17	0.0923	1.95
26	22.95	0.0839	1.93
27	24.88	0.0763	1.90
28	26.97	0.0693	1.87
29	29.26	0.0630	1.84
30	31.75	0.0573	1.82
		Sum of present value:	79.51

The levelized avoided cost of energy becomes:

$$\text{Levelized Avoided Cost} = 79.51 \times 0.106 = 8.43¢ / \text{kW} \tag{A.28}$$

A.1.6 Limitations of levelizing

To obtain the value for the cost of load loss, the B-factor Equation (3) is applied. Note that the values for EC, PL^2, and SC are usually levelized. Assuming that the initial transformer load and annual load growth are such that the transformer does not need to be changed out during its economic life, the expression for PL^2 is:

$$PL^2 = \left\{ \sum_{j=1}^{N} \left[b(1+g)^{j-1} \right]^2 \times PVF_i^j \right\} CRF_i^N \tag{A.29}$$

where

- b is the initial transformer load
- g is the per-unit transformer annual load growth
- N is the economic life (years)

In closed form, the expression is given in Equation (A.30):

$$PL^2 = \frac{b^2}{(1+i)^N} \left[\frac{(1+i)^N - (1+g)^{2N}}{(1+i)-(1+g)^2} \right] CRF_i^N \tag{A.30}$$

Note that in determining the cost of load loss, levelized values such as PL^2 and EC are multiplied. This can be contrasted with the determination of no-load loss, in which levelized values are added.

Consider the following example:

SC	\$50/kW per year (initial)
SC escalation	2% per year
EC escalation	4% per year
EC	\$0.04/kWh (initial)
Initial load	0.9 pu
Load growth	1.5% per year
i	10%
FCR	17%
RF	0.9
LSF	0.1
N	30 years

To determine the equivalent first cost of transformer no-load loss, a present worth could be established as follows in Table A.4.

Table A.4—Limitations of leveling example A factor

Year	SC	EC	EC × 8760	SC + EC	P.V.	Σ P.V.
1	50	0.04	350.4	400.4	364	364
2	51	0.0416	364.4	415.4	343.31	707.31
3	52.02	0.0433	379.0	431.02	323.82	1031.14
—	—	—	—	—	—	—
29	87.05	0.1199	1050.8	1137.85	71.73	5247.15
30	88.79	0.1247	1092.8	1181.59	67.72	5314.87

$$A = \frac{\$5314.87 \times CRF_i^N}{FCR} = \frac{\$5314.87 \times 0.1061}{0.17} = \$3317\,/\,\text{kW} = \$3.32\,/\,\text{W} \tag{A.31}$$

Conversely, if levelized values were to be used, the values for SC and EC would become, using the levelizing factor described in this annex:

Levelized SC	\$59.43/kW per year
Levelized EC	\$0.576/kWh

Resulting in an A factor of:

$$A = \frac{59.43 + 0.0576 \times 8760}{0.17} = \$3318 / \text{kW} = \$3.32 / \text{W} \tag{A.32}$$

which agrees with the value calculated from the year-by-year present worth table.

On the other hand, the present worth table for load loss is shown in Table A.5.

Table A.5—Limitations of leveling example B factor

Year	PU load	SC	SC × R.F.	EC	EC × 8760 × LSF	Total	P.V.	Σ P.V.
1	0.9	50.00	45.00	0.04	35.04	64.83	58.94	58.94
2	0.914	51.00	45.90	0.0416	36.44	68.78	56.85	115.79
3	0.927	52.02	46.82	0.0433	37.90	72.80	54.70	170.49
—	—	—	—	—	—	—	—	—
29	1.366	87.05	78.35	0.1199	105.08	342.27	21.58	1064.93
30	1.386	88.79	79.91	0.1247	109.28	363.43	20.83	1085.76

$$B = \frac{1085.76 \times CRF_i^N}{FCR} = \frac{1085.76 \times 0.1061}{0.17} = \$677.6 / \text{kW} \ = \$0.68 / \text{W} \tag{A.33}$$

Levelized values for SC EC have already been obtained for the A-factor calculation. The levelized value for PL^2 is:

$$\text{Levelized } PL^2 = \frac{0.9^2}{1.1^{30}} \left[\frac{1.1^{30} - 1.015^{60}}{1.1 - 1.015^2} \right] \times 0.1061 = 1.0589 \tag{A.34}$$

Using levelized values, the B factor becomes:

$$B = 1.0589 \times \left(\frac{59.43 \times 0.9 + 0.0576 \times 8760 \times 0.1}{0.17} \right) = \$647.45 / \text{kW} \ = \$0.647 / \text{W} \tag{A.35}$$

which results in a 4.5% error from the actual. The magnitude of the error can be even greater, depending on the relative magnitude of the terms.

The error in utilizing levelized terms as described for the B factor results from multiplying the terms together.

To be precise, the levelized terms should be taken such that they add, rather than multiply together. That is, for calculating the B factor, a multiplier that considers both load growth and the escalation of SC should be determined, and similarly, a multiplier that considers load growth and escalation of EC also is determined. Those multipliers are then applied against the base year value(s).

Assume:

b	is the initial per-unit load
g	is the annual per-unit load growth
d	is the initial value of SC or EC
a	is the annual per-unit growth of SC or EC

The levelized expression becomes:

$$\left\{b^2 d \sum_{j=1}^{j=N} \frac{\left[(1+g)^{J-1}\right]^2 \left[(1+a)^{J-1}\right]}{(1+i)^j}\right\} CRF_i^N \tag{A.36}$$

which in closed form is:

$$\frac{b^2 d}{(1+i)^N}\left[\frac{(1+i)^N - (1+g)^{2N}(1+a)^N}{(1+i)-(1+g)^2(1+a)}\right] CRF_i^N \tag{A.37}$$

Because the load loss calculation contains both SC and EC terms escalating at different rates, two levelizing factors are calculated. For SC:

$$\frac{0.9^2}{1.1^{30}}\left[\frac{1.1^{30} - 1.015^{60} \times 1.02^{30}}{1.1 - 1.015^2 \times 1.02}\right] \times 0.1061 = 1.3037 \tag{A.38}$$

For EC:

$$\frac{0.9^2}{1.1^{30}}\left[\frac{1.1^{30} - 1.015^{60} \times 1.04^{30}}{1.1 - 1.015^2 \times 1.02}\right] \times\ 0.01061 = 1.6403 \tag{A.39}$$

The levelized B-factor calculation becomes:

$$B = \frac{1.3037 \times 50 \times 0.9 + 1.6403 \times 0.04 \times 8760 \times 0.1}{0.17} = \frac{58.6665 + 57.4761}{0.17} \tag{A.40}$$

$$= \$683\,/\,\text{kW} = \$0.683\,/\,\text{W}$$

which agrees with the table.

Note the reasonable balance between the SC and EC portions of the calculation. If the imbalance were more significant, the error between the spreadsheet present worth calculation and the levelized version of (SC × R.F. + EC × 8760 × LSF) PL^2, where SC, EC, and PL^2 are all separately levelized, becomes quite significant.

For transformer changeout in year Y, assuming reinstallation at the initial value of transformer load, the closed form equations for PL^2 are:

For transformer load growth only:

$$\frac{b^2}{(1+i)-(1+g)^2}\left\{\left[\frac{(1+i)^y - (1+g)^{2y}}{(1+i)^y}\right] + \left[\frac{(1+i)^{N-y} - (1+g)^{2(N-y)}}{(1+i)^N}\right]\right\} CRF_i^N \tag{A.41}$$

For transformer load growth and escalation of SC or EC:

$$\frac{b^2 d}{(1+i)-(1+g)^2(1+a)}\left\{\left[\frac{(1+i)^y-(1+g)^{2y}(1+a)^y}{(1+i)^y}\right]+(1+a)^y\left[\frac{(1+i)^{N-y}-(1+g)^{2(N-y)}(1+a)^{(N-y)}}{(1+i)^N}\right]\right\}CRF_i^N \tag{A.42}$$

Spreadsheet calculations are recommended, otherwise, the discussion about levelizing limitations shall be considered, using proper equations for PL^2.

A.2 Minimum acceptable return (MAR)

The MAR is defined as the opportunity cost of capital for the utility that represents the cost of obtaining investment capital. MAR is also commonly referred to as the cost of capital, discount rate, or interest rate.

Components of utility financing include debt and equity financing. Debt capital can be in the form of bonds and equity capital can include preferred and common stock. Debt investments represent a loan to the utility, for example, at a fixed rate of interest with a specified bond maturity value. Preferred stock yields may include a fixed dividend rate that is higher than a bond. Common stock can have a variable dividend payment based upon the fortunes of the utility. Common stock may have a higher rate of return, but with the greater risk to the investor. Table A.6 illustrates this method.

Table A.6—Example of minimum acceptable return

	% of total financing	Rate per year	Weighted cost of capital
Bonds	50%	6%	3%
Preferred stock	10%	10%	1%
Common stock	40%	15%	6%
	MAR	10%	

MAR is the composite of all the utility capital sources and is not the cost of obtaining financing today for one particular project.

A.3 Levelized fixed-charge rate (FCR)

The fixed charge rate is defined as the annual owning costs of an investment as a percent of the investment. The use of a fixed charge rate in common economic comparisons is widely used by the utility industry and is utility-specific.

Components of the fixed-charge rate are as follows:

- Cost of capital (return ON investment)
- Depreciation (return OF investment)
- Income taxes
- Ad valorem (property) taxes and insurance.

The fixed charge rate varies yearly over the life expectancy of the equipment, as shown in Figure A.5. Another common representation of the fixed charge rate is in terms of a levelized value over the life of the equipment. The present worths of the levelized and actual annual values of the fixed charge rate are equivalent over the life of the equipment. This can also be seen in Figure A.4.

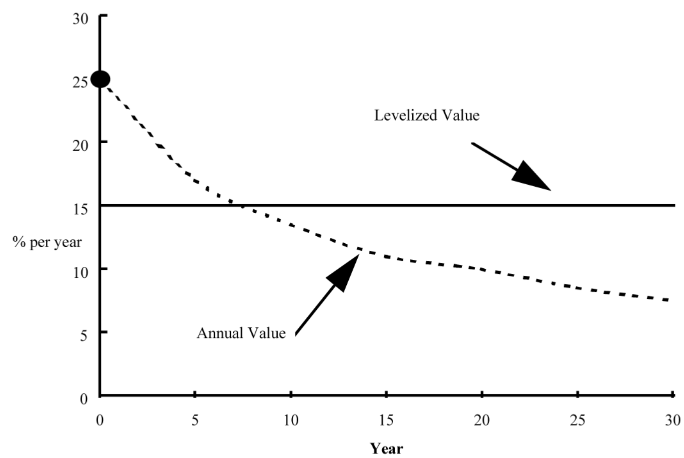

Figure A.5—Fixed charge rate

The cost of capital is the return on the investment or commonly referred to as the MAR. MAR is the composite of all the utility's capital sources and is not the cost of obtaining financing today for one particular project. MAR was discussed briefly in A.2. Levelized values are used for depreciation, income taxes and insurance, and value-added taxes. Levelization was also discussed previously in A.1.5. Typical values of the levelized fixed charge are given in Table A.7.

Table A.7—Typical values of the levelized fixed charge

	Investor owned	Municipals, co-ops
Cost of capital	10–12%	6–8%
Depreciation	1%	1%
Income taxes	2%	0%
Local taxes, etc.	2–4%	2–4%
FCR	15–19%	9–13%

These example values are shown to illustrate the relative weight each constituent applies to the aggregate fixed charge rate. The actual values should be individually determined.

Annex B

(informative)

Description of transformer power losses

B.1 Transformers

The losses in a transformer are basically of two types: *no-load* losses, which occur because the transformer is energized; and *load* losses, which vary with the transformer's loading.

In addition, auxiliary power may be required by fans, pumps, heaters, and other ancillary equipment. This auxiliary power is not necessarily dependent upon the load. All losses and auxiliary power requirements, as discussed in this guide, are expressed in kilowatts.

B.2 Total power losses

These losses are the sum of the no-load losses and the load losses, and do not include auxiliary losses. For purposes of economic evaluation, however, the user should consider no-load, load, and auxiliary power losses if needed.

Care should be taken not to use the term *total load loss,* as the reader will not know whether *load loss* or *total loss* is meant.

Annex C

(informative)

Bibliography

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