Department of Electrical and Computer Engineering

Life-Cycle Loss Evaluation and Total Ownership Cost of Transformers in Vertically-Integrated and Decentralized Energy Systems Integrating Renewable Energy Sources

by

Antonis Lazari

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Περίληψη

Η οικονομική αξιολόγηση της επένδυσης σε κάποιο μετασχηματιστή, βασισμένη στη μέθοδο Συνολικού Κόστους Ιδιοκτησίας (*ΣΚΙ - $*), σκοπό έχει να επιδείξει τις άμεσες και έμμεσες δαπάνες του αντίστοιχου μετασχηματιστή προς στον ιδιοκτήτη ή στον υποψήφιο αγοραστή του. Στόχος της μεθοδολογίας ΣΚΙ είναι να υπολογίσει το συνολικό οικονομικό κόστος του μετασχηματιστή βάσει του αναμενόμενου κύκλου ζωής του. Η εκτίμηση του ΣΚΙ βασίζεται σε μια διαδικασία που συμπεριλαμβάνει την αξιολόγηση και κατ' επέκταση την κοστολόγηση των απωλειών του μετασχηματιστή στο διάστημα της αναμενόμενης ζωής του. Πιο συγκεκριμένα, η διαδικασία της κοστολόγησης των απωλειών ενός μετασχηματιστή προσδιορίζει το άθροισμα της παρούσας αξίας του κόστους για ένα κιλοβάτ (*$/kW*) απωλειών κατά την ωφέλιμη του ζωή. Βάσει της μεθόδου ΣΚΙ μπορεί να γίνει σύγκριση της οικονομικής βιωσιμότητας για δύο ή περισσότερους μετασχηματιστές, καθώς και η σύγκριση προσφορών από κατασκευαστές για την καλύτερη επιλογή αγοράς μεταξύ μετασχηματιστών διαφορετικού κόστους.

Αρχικά, η παρούσα διατριβή παρουσιάζει μια ολοκληρωμένη μέθοδο για τον υπολογισμό του κόστους ηλεκτρικής ισχύς και ενέργειας που απαιτείται για την τροφοδότηση των απωλειών για μετασχηματιστές ισχύος, κατά τον ωφέλιμο κύκλο ζωής τους. Η μεθοδολογία αυτή ανταποκρίνεται στις ανάγκες των χρηστών/ιδιοκτητών μετασχηματιστών που διαθέτουν δικά τους δίκτυα και εγκαταστάσεις παραγωγής και μεταφοράς ηλεκτρικής ενέργειας. Η μέθοδος αυτή στηρίζεται στη χρήση ιστορικών στοιχείων και προβλέψεων που σχετίζονται με το υπό μελέτη ηλεκτρικό σύστημα. Στην παρούσα διατριβή, η προτεινόμενη μέθοδος εφαρμόζεται σε ένα πραγματικό ηλεκτρικό σύστημα μικρής κλίμακας, χρησιμοποιώντας πραγματικές μετρήσεις και στοιχεία (οικονομικά και λειτουργικά). Επίσης, η μεθοδολογία αυτή αναδεικνύει και χρησιμοποιεί κατάλληλα τεχνο-οικονομικά μοντέλα και στατιστικές μεθόδους για τις ανάλογες οικονομικές και λειτουργικές προβλέψεις.

Ωστόσο, η εικόνα στο τομέα της αξιολόγησης των απωλειών μετασχηματιστή γίνεται πιο πολύπλοκη στα σύγχρονα συστήματα ηλεκτρικής ενέργειας με χαμηλές εκπομπές άνθρακα. Για το λόγο αυτό, οι υπάρχουσες μέθοδοι κοστολόγησης απωλειών θα πρέπει να προσαρμοστούν/αναθεωρηθούν για να μπορούν να εφαρμόζονται, επίσης, σε αποκεντρωμένα ενεργειακά συστήματα. Για παράδειγμα, στα σύγχρονα αποκεντρωμένα συστήματα

ηλεκτρικής ενέργειας συνυπάρχουν πολλοί ηλεκτρικοί οργανισμοί (κρατικοί και μη) και ανεξάρτητοι παραγωγοί ανανεώσιμων πηγών ενέργειας. Οι οντότητες αυτές, είναι λογικό να έχουν διαφορετικούς στόχους, καθώς και τρόπους υπολογισμού των δαπανών τους και του προφίλ της παραγόμενης τους ενέργειας. Έτσι, για κάθε περίπτωση η μεθοδολογία κοστολόγησης των απωλειών, του μετασχηματιστή τους, πρέπει να είναι διαφορετική για κάθε ξεχωριστή ενεργειακή οντότητα που εμπλέκεται στα εν λόγω συστήματα.

Κατά συνέπεια, η παρούσα διατριβή παρουσιάζει επίσης μια ολοκληρωμένη μέθοδο κοστολόγησης απωλειών για μετασχηματιστές ισχύος που εξυπηρετούν μεγάλης κλίμακας εφαρμογές ανανεώσιμων πηγών ενέργειας (*ΑΠΕ*). Οι εφαρμογές αυτές μπορεί να ανήκουν είτε σε εποπτευόμενους/κρατικούς οργανισμούς παραγωγής ενέργειας, είτε σε ανεξάρτητους παραγωγούς ενέργειας. Πιο συγκεκριμένα, οι μέθοδοι που προτείνονται εκτιμούν πως ακριβώς θα πρέπει να αξιολογηθούν οι απώλειες, λαμβάνοντας υπόψη το ιδιοκτησιακό καθεστώς των μετασχηματιστών σε σχέση με το ρυθμιστικό πλαίσιο της αγοράς ηλεκτρικής ενέργειας που ισχύει σε κάθε περίπτωση. Εν κατακλείδι, τονίζεται ότι οι μέθοδοι και τα μοντέλα που αναπτύχθηκαν, ανταποκρίνονται στις προσπάθειες για την ανάπτυξη μεθόδων αξιολόγησης του ρίσκου (κινδύνου) και του κόστους ενεργειακών αναγκών, στις διαδικασίες λήψης αποφάσεων, ώστε να ανταποκρίνονται στις διαμορφούμενες ανάγκες των σημερινών αγορών ηλεκτρικής ενέργειας. Τέλος, το περιεχόμενο της παρούσας διατριβής αναμένεται να συμβάλει στις προσπάθειες τροποποίησης και επανέκδοσης του προτύπου IEEE C57.120.1991 “IEEE Loss Evaluation Guide for Power Transformers and Reactors”.

Abstract

The Total Ownership Cost (*TOC*) is a financial estimate indented to provide the transformers' buyers and owners the direct and indirect costs of their transformers' investment. It thus provides a cost basis for determining the total economic value of the transformer over its estimated life-cycle. The approach for estimating the *TOC* of transformers relies on the concept of life-cycle loss evaluation of transformers. In particular, loss evaluation is a process that accounts for the sum of the Present Worth Value (*PWV*) of each kilowatt of loss of transformers throughout their expected life. The *TOC* is typically used to compare the offerings of two or more manufacturers to facilitate the best purchase choice among competing transformers and hence to support the purchase of more efficient units.

Firstly, the thesis presents a holistic method for calculating the cost of the electric power and energy needed to supply the life-cycle losses of power transformers - applicable to transformer users who possess their own generation and transmission facilities. The reported loss evaluation method is based on factors derived from relevant historical and forecasted data that are combined to determine the Total Ownership Cost of Power Transformers. Most importantly the proposed method is evaluated on a small scale real system, by incorporating relevant financial data and system characteristics through appropriate techno-economic models as well as statistical evaluations.

However, the picture of loss evaluations becomes more complex in the context of low carbon electricity markets. To this end, loss evaluation methods should be adjusted for evaluating the ownership cost of transformers operated in a decentralized energy environment. For example, under liberalized electricity markets, several regulated utilities and independent renewable power producers co-exist but have diversified ways of assessing their capital costs, system expenditures and generation profiles. Thus, the methods for capitalizing their own transformer losses should be different.

To this extent, this thesis also offers a comprehensive loss evaluation method to calculate the total ownership cost of power transformers serving large scale *RES* applications. These transformers may be owned by either Independent energy producers or by Regulated Utilities. More specifically, the methods derived appreciate exactly how losses should be evaluated, bearing in mind the ownership status of the transformers in relation to the regulatory

framework of the electricity market they exist in. In conclusion, it is highlighted that the methods and models developed, for the scope of this thesis, respond to the ongoing efforts of developing risk and cost-based decision making processes in today's competitive and dynamic energy markets. It is also expected to contribute to the ongoing efforts of modifying and reissuing IEEE standard C57.120.1991 ''IEEE Loss Evaluation Guide for Power Transformers and Reactors''.

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Introduction

1.1 General Remarks

Transformers constitute some of the key energy-consuming components in electrical power systems. Based on a study published in [1], power and distribution transformers contributed: a) about 40% of the losses for non-generating public/government utilities and agencies, and b) over 16% of the losses for investor-owned/private utilities. Furthermore, studies that have been performed on behalf of the European Copper Institute in 2005 [2] have shown that improving the energy efficiency of the European stock of transformers by 40% would result in about 22 TWh annual energy savings, equivalent to an annual reduction in green-house gas emissions of about 9 million tons of CO_2 equivalent.

The cost-effective potential resulting from the selection of improved energy efficiency criteria during the installation of new transformers and/or the retrofitting of existing units can result in significant losses reduction and benefits for electrical power systems. Modern energy-efficient transformers are designed to reduce total power losses (*NLL* - no-load losses, *LL* - load losses, *AUX* - auxiliary losses). Transformer manufacturers have developed new manufacturing techniques and new types of core materials to provide cost-effective and energy-efficient transformers to the interested parties. In essence, they reduce energy consumption and consequently reduce the generation of electrical energy and the resulting greenhouse gas emissions. Thus, as system investment and energy costs continue to increase, electric utilities and public companies/government agencies are more and more interested in installing energy-efficient transformers in their networks.

Energy-efficient transformers cost more but use less energy than low efficiency units. The decision as to whether to purchase a low-cost, inefficient transformer or a more expensive, energy-efficient transformer is primarily an economic one. The justification for selecting one transformer over another should be based upon the initial capital cost plus the operating expenses encountered during its useful lifetime. The common practice used by the interested parties for determining the life-time operating expenses, and thus, the cost-effectiveness of transformers, is based on a life-cycle loss evaluation procedure that yields the subsequent Total Ownership Cost (*TOC* - *$*) of transformers.

It is important to recognize that the perspective of each interested entity, as far as the transformers' life-cycle loss evaluation is concerned, may be different. Even within the same country, different entities may have diverse operation targets and financial objectives. For example: a) the transformer loss evaluation procedure for electric utilities involves understanding and assessing the total cost of generating, transmitting and distributing transformer losses; b) the transformer loss evaluation procedure for industrial and commercial users requires an understanding and assessment of the electric rates they pay to the electric utility.

In general, the transformers' loss evaluation method may be considered as a planning tool where its implementation largely depends on the discretion of each concerned utility/entity. Thus, there could be major fluctuations when defining and evaluating the system cost and load parameters used in loss evaluation processes. These fluctuations are due to the objectives (operational and financial) set by each utility/entity, as well as due to the depth of analysis required. The elements engaged in the processes are: a) the load characteristics of the system, b) an appropriate discount rate based on the overall financial objectives of the business and c) relevant capital (system capacity costs or capital fixed cost) and operating expenditures.

1.2 Life-Cycle Loss Evaluation of Transformers

The loss evaluation in transformer industry is a process that accounts for the sum of the present worth value of each kilowatt of loss of transformers throughout their expected life. The power losses of transformers are, by definition, the no-load losses (NLL – kW), the load losses (LL – kW) and the auxiliary losses (AUX – kW). Thus, under the process of loss evaluation each type of transformer loss (NLL, LL, AUX) is assessed on the basis of its demand (D - $\$/kW$) and energy ($E$ - $\$/kWh$) components. The demand component (D) is the cost of installing a kW of additional system capacity to serve the power used by the losses [3]. The energy component (E) is the present value of the energy that will be used by one kilowatt of loss during the life-cycle of the power plant under study [3]. To this extent, the demand and energy components of losses are the prevailing factors in the process of establishing the cost value of the electric power and energy needed to supply the life-cycle losses of transformers.

Both demand and energy components are appropriately annuitized to provide a total loss factor figure ($\$/kW$) which accounts for the sum of the present worth (i.e. discounted value) of each kilowatt of loss of power transformers throughout their expected life. The loss evaluation process subsequently yields the discounted Total Value of Losses (TVL - $\$$) of transformers over their expected, in-service, life. The *TVL* of transformers can be calculated using the generic illustration in (1-1). Table 1.1 tabulates the further particulars of the nomenclature used in (1-1).

$$\begin{gathered} TVL = CostNLL + CostLL + CostAUX \\ \\ CostNLL = f_1(D,E) \times NLL \\ CostLL = f_2(D,E) \times LL \\ CostAUX = f_3(D,E) \times AUX \end{gathered} \tag{1-1}$$

Table 1.1
Nomenclature

***TVL* – ($)**	Present value of transformer's lifetime Total Value of Losses.
NLL* – (kW)	No–Load Losses of Transformer.
LL* – (kW)	Load Losses of Transformers.
AUX* – (kW)	Auxiliary Losses of Transformers.
$f_1(D,E)$ – ($/kW)**	No–Load Losses Cost Rate – *The figure that represents the present value of a kW of loss of NLL throughout the transformer lifetime.*
$f_2(D,E)$ – ($/kW)**	Load Losses Cost Rate – *The figure that represents the present value of a kW of loss of LL throughout the transformer lifetime.*
$f_3(D,E)$ – ($/kW)**	Auxiliary Losses Cost Rate – *The figure that represents the present value of a kW of loss of AUX throughout the transformer lifetime.*
* See Section 1.3 ** Power losses cost rates are a function of the Demand (*D*) and Energy (*E*) Components of Losses	

1.2.1 Total Ownership Cost

The Total Ownership Cost (*TOC* - *$*) of a transformer is subsequently derived by the purchase price (*PP* - *$*) of the transformer plus its *TVL* as indicated in (1-2).

$$TOC = PP + TVL \tag{1-2}$$

Thus, the Total Ownership Cost of a transformer is defined as a financial estimate that is used to provide the transformer owners/investors the direct and indirect costs of their transformer investments. It is mainly used as an economically based decision tool that can be applied under the following circumstances:

- **Modify transformer designs accordingly:** It is well accepted, that loss levels are far from optimum in today's economy, and at all times a reduction in loss levels is desirable. This would inevitably increase the selling prices of transformers. However, the TOC approach reinforces the fact that reducing the losses (by more efficient and expensive units) would mean an overall reduction in the transformers' total operating and ownership costs. The net effect of such an approach would be firstly to defer the need for utility rate increases and secondly to accomplish significant energy conservation.

- **Compare the relative merits between competing transformers:** The life-cycle loss evaluation process and the subsequent *TOC* enable a user to compare the offerings of two or more manufacturers in making the best purchase choice among competing units and hence support the purchase of more efficient units. Using the loss evaluation factors ($f_1(D,E), f_2(D,E), f_3(D,E)$), the economic benefit of a high-first-cost, low-loss unit can be compared with a unit with a lower capital cost and higher losses.

- **Estimate the ideal time to retire/replace existing transformers:** Loss evaluation processes provide information to establish the optimum time to retire or replace existing units with more-efficient transformers. The information provided account for the economic viability comparing the load-growth implications under the existing and the candidate transformers. The procedure is termed as "Economic Transformer Change-out Assessment".

1.3 Transformer Power Losses

1.3.1 No-Load Losses

The no-load losses (*NLL - kW*) [1], [3] of a transformer, or core losses, are those losses that are incident to the excitation of the transformer. *NLL* magnitude is non-load-dependent and they are constant as far as the transformer core is excited, irrespective to the loading condition of the transformer. They include di-electric 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. The core loss component includes the hysteresis and the eddy current losses of the core. Hysteresis losses and eddy current losses contribute over 99% of the no-load losses, thus any other losses are often neglected. Core 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. When transformer no-load losses are compared, the same reference temperature should be used.

1.3.2 Load Losses

The load losses (*LL - kW*) [1], [3] of a transformer, or copper losses, are those losses that are incident to the carrying of a specified load. 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, and other parts, and the loss due to circulating currents in parallel windings or in parallel winding strands. These losses are proportional to the square of the transformers' load and the absolute temperature of the windings. For comparison purposes, load loss values of transformers are provided at a reference load and winding temperature.

1.3.3 Auxiliary Losses

The auxiliary losses (*AUX – kW*) [1], [3] of a transformer express the power required for cooling equipment such as fans and pumps to increase the loading capability of power transformers. These losses do not apply for distribution transformers, since they have no electrical-operated cooling medium.

The energy consumption of auxiliary equipment depends on the horsepower of the fans and pumps and the length of time they are running. The length of time they are running depends on the transformer loading throughout the year. This can be determined from the peak loading projections. The common practice is to turn on the cooling fans when the transformer load reaches 33% of its rated load and turn on the pumps when the transformer load reaches 67% of its nameplate rating [3].

1.4 Financial Rational of Loss Evaluation Method

The economics related to transformer design, manufacture and the referenced life-cycle loss evaluation need to be thoroughly understood. There are three standardised methods for financially evaluating the losses of power/distribution transformer over their useful life [1]:

1. **Equivalent Investment Cost Method**
   The equivalent investment cost method involves the addition of the total cost of transformer's power losses (*CostNLL*, *CostLL*, *CostAUX*) to the *TOC* formula (1-2) without any modification. The total cost of transformer power losses is, thereby, modified to account for the impact of adjacent network levels (transmission,

distribution) on the total losses to account for their coincidence loss behaviour. The cost of transformers' power losses are calculated as given in (1-3).

$$\begin{aligned} CostNLL &= f_1(D,E) \times NLL \times Loss\_Multiplier \\ CostLL &= f_2(D,E) \times LL \times Loss\_Multiplier \\ CostAUX &= f_3(D,E) \times AUX \times Loss\_Multiplier \end{aligned} \tag{1-3}$$

The loss multiplier (*Loss_Multiplier*) accounts for the additional losses imposed on the transmission and, when applies, distribution system to meet the total transformer losses.

2. Levelized Annual Cost Method

The levelized annual cost method involves converting each transformer's power losses cost component, in *TOC* formula (1-2), into an annual levelized cost over the lifetime of the transformer. Each component is transformed into an annual levelized cost through multiplying by a conversion factor; carrying charge rate or fixed charge rate ($FCR - p.u.$).

The carrying charge rate or the fixed charge rate converts the levelized annual cost of losses into a capitalized value. The carrying charge rate is comprised from:

- Minimum acceptable rate of return
- Book depreciation
- Income taxes
- Local property taxes and insurance

3. Present Worth of Annual Revenue Requirements Method

The present worth method requires taking each component of the *TOC* formula and refer it back to a common/benchmark date. This can be then used as a comparison reference between various transformer designs.

In the present worth of annual revenue requirements method, the levelized annual cost method *TOC* formula is multiplied by a uniform present worth multiplier ($PV_m - p.u.$) as provided in (1-4). Within (1-4), d is the discount rate ($p.u$) and N is the total number of annual costs to be considered for each case. (1-4) converts the annual cost values into a present worth value.

$$PV_m = \sum_{j=1}^{N} \frac{1}{(1+d)^j} = \frac{(1+d)^N - 1}{d \times (1+d)^{N-1}} \tag{1-4}$$

1.5 Literature Survey – State of the Art

An extensive literature search has been performed to identify the characteristics of the loss evaluation techniques developed in the previous years as well as their practical implementation. The loss evaluation methods found in the literature [3] – [20] are separated into two large categories: a) the distribution transformers' loss evaluation procedures for industrial and commercial users, and b) the power and distribution transformers' loss evaluation procedures for electric utilities. The most important methodologies identified in literature are described in the following sections.

1.5.1 Loss Evaluation Processes for Industrial and Commercial Users

The transformer life-cycle loss evaluation procedure for industrial and commercial users requires the understanding and assessment of the electric rates of the purchased energy, needed to cover the transformer losses. The Industrial/Commercial users should capitalize their transformers' power losses according to the demand and energy rates charged by the utility, thus accounting both for the capacity cost and energy costs. The charges are based on the category that transformer is to be placed, i.e. transmission system – power transformers, distribution system – distribution transformers.

The most comprehensive material regarding power/distribution transformers' loss evaluation processes for Industrial and Commercial users is quoted in a work reported in 2003 [12]. The referenced work accommodates the present value approach (1-4) to express the cost of losses as a function of the transformer characteristics, electricity cost and discount rate. In particular, the work highlights the particular differences according to the techno-economic evaluation used (i.e. industrial/commercial users or electric utilities) and illustrates the impact of several factors (transformer load, discount rate, etc) on the evaluation method.

Moreover, the work in [12] gives particular attention on the transformer's loss figures provided by the manufacturer/vendor. To this end, (1-5) illustrates the proposed procedure [12] to modify the transformer quarantined losses (tested at transformer rated voltage and current) to the equivalent losses for the rated transformer load. In particular, [12] defines the per unit total value of losses (*TVL*) of the transformer as the sum of the per unit no-load losses (*NLL*) and the per unit load losses (*LL*) multiplied by the square of the per unit load (1-5). The figures in (1-5) are in per unit quantities. Thus, [12] proposes that for any transformer applies that:

$$T = NL + L \times x^2$$
$$y = T/x = NL/x + L \times x \qquad (1\text{-}5)$$

Where,

T = the total per unit loss at load χ based on rated load

NL = no-load per unit loss

L = load per unit loss at rated load

χ = per unit load

To express the transformer losses in per unit on the actual load in *kVA*, instead of on the rated *kVA* as the base, (1-5) is divided by χ. The procedure leads to y (1-5), the per unit load loss based on the actual load of *kVA*. In order to define the minimum point of the per unit loss as a function of load, two important conclusions are extracted as appear in (1-6).

$$NL = L \times x^2$$
$$y = 2 \times (L \times NL)^{1/2} \qquad (1\text{-}6)$$

Equation (1-6) highlights that the minimum per unit loss occurs at the load at which the actual load loss ($L \times x^2$) equals the no-load loss NL. In addition, (1-6) indicates that the minimum per unit total loss, based on the actual load (y) is defined by the product of the rated load loss (L) and the no-load loss (NL) both based on rated load.

In addition to the above remarks, the work reported in [12] gives particular emphasis on the use of transformer loss evaluations in Simple Payback period studies. These are mostly useful to the vendors when quoting their most competitive design for a specific transformer application. The simplified idea relies on the use of the payback period of the transformer, instead of the sum of the present value of annual costs. The main objective of the work in [12] is to calculate the most suitable (economically efficient) transformer's loss cost rates for a given payback period in years.

An identical industrial/commercial loss evaluation approach is reported in 2007 [13] through a decision support system (*DSS*) for evaluating transformer investments in the industrial sector. The referenced method, also, incorporates the present worth of annual revenue requirements approach. The methodologies discussed in [12] and [13] are applicable to distribution transformers (installed at the distribution level) in vertically integrated energy systems, serving large industrial or commercial applications.

For distribution transformers, the total power losses (*TL - kW*) are the sum of no-load losses (*NLL - kW*) and load losses (*LL - kW*) as given by (1-7). Thus, following formula (1-1) the Total Value of Losses (*TVL - $*) for distribution transformers are the sum of no-load losses cost (*CostNLL - $*) and the load losses cost (*CostLL - $*) during the transformer's useful life.

$$TL = NLL + LL \tag{1-7}$$

Following the derivation of *TVL* in (1-1), $f_1(D,E)$ and $f_2(D,E)$ are calculated as shown in (1-8). *HPY* is the hours per year the transformer is predicted to be in operation mode, whereas the *EP* is some constant electricity price, in *$/kWh*, the industrial/commercial user pays to the electric utility. The Total Value of Losses for a distribution transformer (TVL_d) is, also, illustrated in (1-8).

$$\begin{gathered} f_1(D,E) = PV_m \times HPY \times EP \\ f_2(D,E) = f_1(D,E) \times L^2 \\ TVL_d = f_1(D,E) \times NLL + f_2(D,E) \times LL \end{gathered} \tag{1-8}$$

A similar methodology is incorporated when an annual escalation rate (GR_i – growth rate for year i) is enforced for the electricity charges (*EP*) that may apply. If this is the case, the procedure in (1-9) may then be utilised. The Annual Value of Losses (*AVL - $*) formula may be calculated for all years (*i*) during transformer lifetime to provide the total cost of losses on annual basis. Following this, the TVL_d may be calculated by using the present value approach for each year during the transformer lifetime.

$$AVL_i = (NLL + LL \times L^2) \times HPY \times EP_{i-1} \times \left(1 + GR_i\right)$$
$$TVL_d = \frac{AVL_1}{(1+d)} + \frac{AVL_2}{(1+d)^2} + \cdots\cdots + \frac{AVL_N}{(1+d)^N} \tag{1-9}$$

If the transformer is offered to the industrial user at a bid price *BP - $*, then the total ownership cost *TOC - $* of the transformer is equal to the sum of its bid price *BP* and the present value of the transformer losses (TVL_d) throughout its lifetime.

1.5.2 Loss Evaluation Processes for Electric Utilities

1.5.2.1 IEEE Standard C57.120-1991

In 1991, the IEEE C57.120 [3] has been formed to provide a universal method for establishing loss evaluation factors for power transformers and reactors owned by electric utilities. The quoted standard method is based on the present worth of annual requirements which is equivalent to the total levelized annual cost method established in previous approaches. The transformer annual costs are translated into a levelized annual cost (i.e. fixed losses cost throughout transformer lifetime) by using (1-4) and (1-10). Equation (1-4) provides the present worth of transformer losses' annual requirements, whereas (1-10) expresses the Capital Recovery Factor (*crf – p.u.*). In (1-10), *N* is the number of transformer lifetime in years. The sum of the present worth of annual requirements is multiplied by the *crf* to provide the transformers' total levelized annual cost. The concept of levelization is illustrated in Figure 1-1. The quoted IEEE standard loss evaluation method refers to vertically integrated utilities that possess their own generation and transmission facilities.

$$crf = \frac{d(1+d)^N}{(1+d)^N - 1} \tag{1-10}$$

The IEEE method allows a user to determine, on a dollars-per-kilowatt ($/kW) 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. This figure represents the maximum amount that can be spent to save a kilowatt of loss. The IEEE standard provides formulas by which the costs of energy, power and money, and loading pattern of a transformer can be converted to dollars-per-kilowatt values of the transformer losses.

The basic concept of the IEEE standard is that the evaluation of each type of loss (*NLL*, *LL*, and *AUX*) is the sum: 1) of the demand component of losses, and 2) the energy component of losses.

1) The demand component of losses is the cost of installing additional system capacity to serve a kW of loss, in \$/kW.
2) The energy component of losses is the present value of the energy that will be used by one kilowatt of loss during the lifetime of the transformers, in \$/kWh. This is subsequently converted to a \$/kW figure.

The demand and energy component of losses are subsequently levelized (i.e. converted to yearly values) and then the sum is divided by the fixed charge rate for transformers and any other appropriate factors, to give the equivalent loss cost rates (*NLL*, *LL*, *AUX*). This process is given in (1-11).

$$Loss\ cost\ rate(\$/kW) = \frac{\left[\begin{pmatrix} cost\ of \\ installing \\ a\ kW\ of \\ plant \end{pmatrix} \times \begin{pmatrix} fixed\ charge \\ rate\ of\ plant \end{pmatrix}\right] + \left[\begin{pmatrix} cost\ of \\ a\ kWh \end{pmatrix} \times \begin{pmatrix} hours\ per \\ year\ the \\ transformer \\ is\ energized \end{pmatrix}\right]}{\begin{pmatrix} fixed\ charge\ rate \\ of\ transformers \end{pmatrix}} \tag{1-11}$$

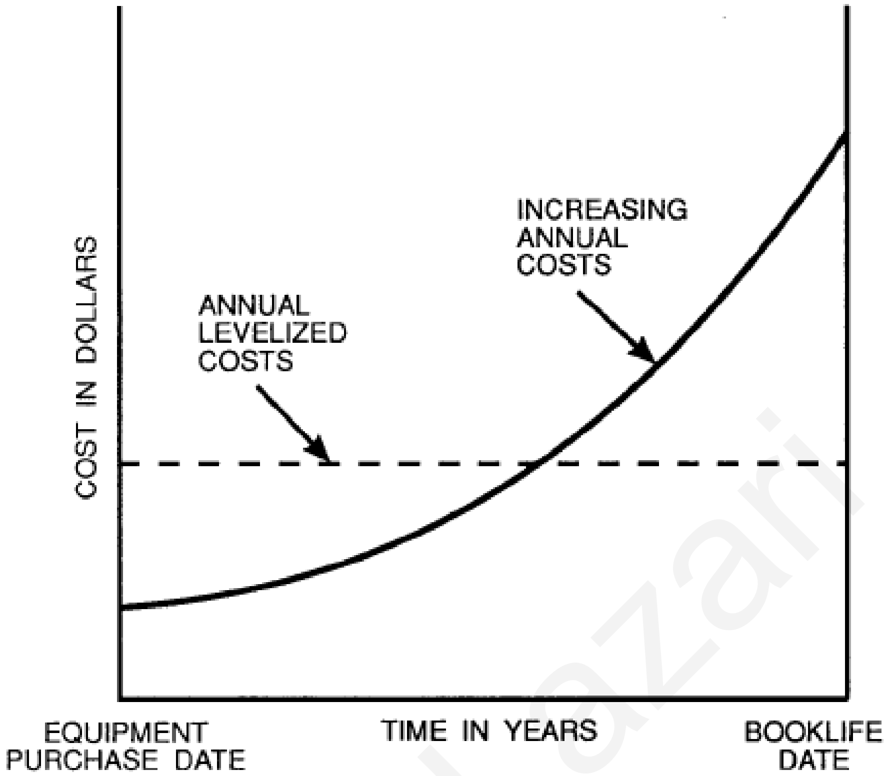


Figure 1-1: Levelization process [3]

More precisely, according to the standard quoted in [3], the power transformers' loss cost rates for no-load losses, load losses and auxiliary losses are as per (1-12). Table 1.2 tabulates the further particulars of the nomenclature used in (1-12).

$$f_1(D,E) = \frac{LIC + LECN}{ET \times FCRT \times IF}$$
$$\Rightarrow LECN = crf \times HPY \times AF \times \sum_{j=1}^{N} CYEC \times \frac{(1+GR_j)^j}{(1+d)^j}$$

$$f_2(D,E) = \frac{LIC \times PRF^2 \times PUL^2 + LECL \times TLF^2}{ET \times FCRT \times IF} \tag{1-12}$$
$$\Rightarrow LECL = crf \times HPY \times \sum_{j=1}^{N} CYEC \times \frac{(1+GR_j)^j}{(1+d)^j}$$

$$f_3(D,E) = \frac{LIC + LAEC}{ET \times FCRT \times IF}$$

Table 1.2
Nomenclature

LIC – ($/kW-yr)	Levelized Annual Total System Investment Cost – *The additional generation and transmission system capacity needed to supply the power used by the losses.*
LECN – ($/kW-yr)	Levelized Annual Energy and Operating cost of No-Load Losses.
ET – (p.u.)	Efficiency of Transmission – *The energy received at the input terminals of the transformer divided by the energy transmitted from the source.*
FCRT – (p.u.)	Fixed Charge Rate for Transformers – *The levelized annual cost divided by the cost of investment.*
IF – (p.u.)	Increase Factor – *The factor representing the total that the user must pay to acquire the transformer, including the purchase price, overhead, fee, tax, etc. based on its value.*
PRF – (p.u.)	Peak Responsibility Factor – *The power transformer's load at the time of the system peak divided by the power transformer's peak load.*
PUL – (p.u.)	Peak-per-unit Load – *The average of yearly peaks over the lifetime of the transformer, divided by the rating at which the load losses are guaranteed and tested.*
LECL – ($/kW-yr)	Levelized Annual Energy and Operating cost of Load Losses.
TLF – (p.u.)	Transformer Loading Factor – *The root-mean-square value of the predicted loads of the power transformer over a representative yearly period is an equivalent load.*
LAEC – ($/kW-yr)	Levelized Annual Energy and Operating Cost for cooling system/auxiliary equipment.
AF – (p.u.)	Transformer Availability Factor (i.e. the proportion of time/year that the transformer is predicted to be energised)
CYEC – ($/kWh)	Current Year Energy Cost (usually initial year of evaluation process)

1.5.2.2 Distribution Transformer Loss Evaluation

The most comprehensive material related to transformers' loss evaluation processes is found in a series of two papers published in 1981 [14], [15]. The work refers to a complete loss evaluation method applicable to distribution transformers in vertically-integrated systems. More precisely, the total levelized annual cost method is extended to properly account for conditions of energy cost inflation, load growth and transformer change-out. The reported method may be used only by investor-owned utilities which have their own generation and transmission facilities.

Part I refers to the application of the total annual cost method, extended to properly account for energy cost inflation, load growth and transformer change-out [14] when capitalizing for the transformer losses. The methodology provided, also, refers to the occasional need for evaluation and costing of reactive and regulation losses. The discussion in [14] concludes that the effect of regulation and reactive losses is significantly smaller than the cost of power losses, thus in most of the procedures it is neglected. This is mainly due to the time needed to perform the evaluation of reactive and regulation losses in respect to their proportion on the overall transformer losses. Moreover, a detailed derivation of the transformer equivalent levelized annual peak load is provided. This is modified to account for circumstances of energy cost inflation and transformer change-out practices. As a final note, the paper discusses the various loss cost rates obtained in industry (various regulated utilities in different countries).

In particular, [14] proposes the Total Levelized Annual Cost (*TLAC - $/yr*) of a transformer to its relevant regulated utility owner. The *TLAC* is the sum of the levelized annual transformer cost to utility and the equivalent levelized annual *TVL* (1-1), as given by (1-13). *CT* is the initial transformer cost to utility, in $, and *CC* is the levelized annual carrying charge rate, expressed in p.u.

$$TLAC = CT \times CC + TVL \tag{1-13}$$

Following the theoretical formulation in (1-1), the work in [14] proposes the levelized annual loss cost rates for no-load losses ($f_1(D,E)$ - *$/kW*) and load losses ($f_2(D,E)$ - *$/kW*) of a distribution transformer in a vertically-integrated power system, as per (1-14). The loss cost rates are derived in respect to their equivalent demand (*D - $/kW*) and energy (*E - $/kWh*) components of losses. The demand (*CSYSB - $/kW*) and energy cost (*CEBL - $/kWh*) components of the no-load losses should be evaluated according to the related costs and energy for base load generation [14]. In contrast, the demand (*CSYSP - $/kWh*) and energy (*CEPL - $/kWh*) cost component of the load losses should be evaluated according to the related costs and energy for peaking generation. Table 1.3 tabulates the further particulars of the nomenclature used in (1-14).

It should be noted that the load loss cost rate ($f_2(D,E)$) is separated into its demand and energy component by utilizing two separately calculated equivalent transformer annual peak loads (*PEQO – p.u.* and *PEQE – p.u.*). *PEQO* is the levelized annual peak load of the transformer that may concurrently account for the levelized annual transformer losses ($PEQO^2$). The *PEQO* results from the series of annual peak loads (in per unit) expected over the life cycle of the transformer under study as per (1-15).

$$f_1(D,E) = CSYSB \times DISC \times CC + 8760 \times CEBL$$

(1-14)

$$f_2(D,E) = CSYSP \times DISC \times CC \times PRF^2 \times PEQO^2 + 8750 \times LSF \times CEPL \times PEQE^2$$

Table 1.3
Nomenclature

CSYSB – ($/kW-yr)	System Investment Cost per Unit of Base Load
DISC – (p.u.)	Discount Factor for System Investment Cost
CEBL – ($/kWh-yr)	Levelized Incremental Energy Cost for Base Load
CSYSP – ($/kW-yr)	System Investment Cost per Unit of Peak Load
CEPL – ($/kWh-yr)	Levelized Incremental Energy Cost for Peak Load
LSF – (p.u.)	Transformer Annual Loss Factor
PEQO – (p.u.)	Transformer Equivalent Annual Peak Load (No Inflation)
PEQE – (p.u.)	Transformer Equivalent Annual Peak Load (Energy Cost Inflation)

The energy-related cost items, such as fuels, repairs and maintenance, operation, etc., would be subject to inflation throughout the evaluation period (i.e. the life cycle of distribution transformers). Therefore, the effect of inflation is factored in the formula of the levelized annual transformer losses $PEQE^2$ as proposed by (1-15). In (1-15), PV_j (1-4) is the present worth factor for each year j considered, crf (1-10) is the capital recovery factor, d is the real discount rate in p.u., P_o is the initial transformer annual peak load (p.u.), CR_j is the transformer's annual compound peak load growth rate (p.u.) and IR_j is annual constant or variable inflation rate for each year j considered in the analysis.

$$PEQO^2 = \left[\sum_{j=1}^{N} P_j^2 \times PV_j\right] \times crf$$

$$PEQE^2 = \left[\sum_{j=1}^{N} P_j^2 \times PV_j \times (1 + IR_j)^{j-1}\right] \times crf \qquad (1\text{-}15)$$

$$\Rightarrow P_j = P_o \times (1 + CR_j)^{j-1}$$

Part II is a companion paper which describes in detail the system cost parameters and the load characteristics that are used in the cost of loss evaluations of distribution transformers [15]. The load characteristics and system cost parameters used in distribution transformer loss evaluation formulas can have a significant effect on the evaluation method. There is a wide variation in parameters used by various utilities to perform these evaluations, thus the proper selection of these parameters is discussed. More precisely, the work in [15] describes the derivation of transformer load parameters in respect to the number of customers served by the unit. The loading factors derived are: a) transformer loading factor (LF –p.u.) and the consequent loss load factor (LLF – p.u.), b) transformer coincidence factor (CF – p.u.), c) peak responsibility factor (distribution system; PRFD –p.u., system; PRFS – p.u.) and d) max diversified demand (D – p.u.). Following these, the work provides representative distribution transformer load characteristics, as a function of the number of customers served. The indicative load characteristics provided are applicable to loss evaluation processes where specific utility data are not available.

The work in [15], also, describes the correct derivation of the equivalent economic parameters to be used following the total levelized annual cost method to capitalize for the transformer losses. The cost parameters described in [15] are: a) Levelized Annual Carrying Charge Rate (CC – p.u.), b) discount factor (DISC – p.u.), c) discount rate (d – p.u.), d) rate of return (I – p.u.), and e) inflation rate (IR – p.u.). The referenced parameters are then used to derive the equivalent incremental energy costs and the equivalent fixed costs for generation, transmission and distribution categories.

Moreover, particular emphasis is given on the economic analysis of transformer change-out load. The economic transformer change-out load (point B on Figure 1-2) is the annual peak load at which the annual cost of the transformer in use (T1) is greater than the annual cost of the replacement transformer (T2) by an amount equal to the return on delaying the change-out by one year. That return (shown as C in Figure 1-2) is equal to the change-out expense multiplied by the expected rate of return. The determination of the economic change-out load involves the calculation of transformer loss costs and must be consistent with the loss evaluation procedure used.

Some sporadic references have, also, contributed to the loss evaluation endeavors for distribution transformers owned by regulated electric utilities. The work in [16] relates to a simplified approach to evaluate the loss coefficients based on the type of transformer being considered, its size and service as well as loading conditions. The methodology accounts for constant annualized fixed and variable cost on a per kW basis, in conjunction with an economic capitalization factor to obtain the effective real cost-to-date.

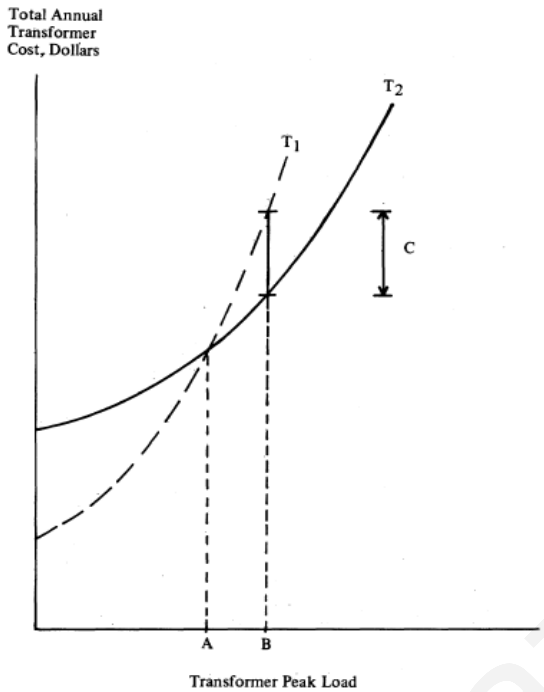


Figure 1-2: Determination of economic change-out load [15]

1.5.2.3 Loss Evaluation Methodology Incorporating Environmental Cost

In the context of the recent global efforts for energy savings the external environmental costs should be taken into account in transformer's life-cycle loss evaluation processes and their equivalent *TOC*. The environmental cost refers to the costs that are associated to the purchase of green-house *(GHG*) emission credits/allowances. The life-cycle processes should incorporate the *GHG* emissions allowances costs associated with various types of emissions resulting from the combustion of fossil fuel so as to compensate for transformer losses throughout its lifetime.

Significant evolvement towards accounting the environmental costs in transformer's loss evaluation processes was performed in 2008 [17], in 2009 [18] and later in 2010 [19]. More precisely, the methodologies referenced in [17] and [19] introduce the environmental cost into the conventional *TOC* formula (Section 1.5.2.1) referenced in IEEE Standard C57.120-1991 [3].

The most important remark of [17] – [19] is the definition of the reference transformer concept. The reference transformer has to be part of the transformer specification of the electric utility, i.e. define the transformer's reference no-load losses (NLL_r - kW) and reference load losses (LL_r - kW). For any evaluated transformer that has total energy losses less than the total energy losses of the reference transformer, the environmental cost is considered negative, providing a further incentive for transformer owners to invest to low loss designs. If otherwise, the environmental cost is considered positive. The key of computing the aforementioned environmental cost is to find the energy losses that stem from the difference between the total energy losses of the evaluated transformer and the total energy losses of the reference transformer. The selection of the reference transformer losses is based on the contribution of the transformer energy losses to the total greenhouse gas emissions of the generation system of the considered electric utility and their responsibility to the violation of the maximum values imposed by international standards or protocols concerning each country. The reference transformer must correspond to the maximum permissible losses per kVA rating that do not violate these limits that may impose an environmental penalty to the electric utility.

Initially, the annual energy losses corresponding to the no-load losses of each evaluated transformer are calculated (E_{NLLo} - *kWh/yr*) by multiplying the given no-load losses (NLL_o - *kW*) by the availability factor (*AF – p.u.*) and the total number of hours per year (*HPY*), based on (1-16). Similarly, the annual energy losses corresponding to the load losses are calculated (E_{LLo} - *kWh/yr*) by multiplying the given load losses (LL_o - *kW*) of each evaluated transformer by the square of the load factor (*LF – p.u.*) and the total number of hours per year (*HPY*), as indicated by (1-16).

$$
\begin{aligned}
E_{NLLo} &= NLL_o \times AF \times HPY \\
E_{LLo} &= LL_o \times LF^2 \times HPY
\end{aligned}
\tag{1-16}
$$

The same procedure is followed so as to compute the annual energy losses (E_{NLLr} - *kWh/yr* and E_{LLr} - *kWh/yr*) of the reference transformer due to no-load (NLL_r – *kW*) and load losses (LL_r – *kW*), respectively. These can be calculated as per (1-17).

$$
\begin{aligned}
E_{NLLr} &= NLL_r \times AF \times HPY \\
E_{LLr} &= LL_r \times LF^2 \times HPY
\end{aligned}
\tag{1-17}
$$

The environmental cost of transformer losses is calculated based on the annual energy loss difference between the evaluated transformer and the reference transformer. The annual energy no-load loss difference between the evaluated transformer and the reference transformer, ΔE_{NLL} – kW, and rated annual energy load loss difference between the evaluated transformer and the reference transformer, ΔE_{LL} – kW, are computed as in (1-18).

$$\Delta E_{NLL} = E_{NLLo} - E_{NLLr}$$
$$\Delta E_{LL} = E_{LLo} - E_{LLr} \tag{1-18}$$

It should be noted that if $\Delta E_{NLL} > 0$, that is, if the no-load loss of the evaluated transformer is greater than the no-load loss of the reference transformer, then, the decision to purchase from the considered transformer manufacturer will be negatively affected. On the other hand, if $\Delta E_{NLL} < 0$, that is, if the no-load loss of the evaluated transformer is smaller than the no-load loss of the reference transformer, then this partially affects positively the purchasing decision. Similar conclusions can be drawn for the ΔE_{LL} positive and negative values.

In addition to these, the studies in [17] – [19] incorporate a detailed calculation of the current year (initial year of evaluation study) GHG emission cost factor (C - $\$/kWh$) according to the combusted fuels (net calorific values of fuels) in the generation mix and the efficiency of the generation turbines. The current year GHG emission cost factor C is computed as per (1-19).

$$C = C_{cy} \times \sum_{i=1}^{K} (f_i \times C_{eq,i}) \tag{1-19}$$

In (1-19) C_{cy} ($\$/t_{CO2}$) is the current year GHG emission cost, where t_{CO2} denotes the tones of equivalent CO_2 emissions, $C_{eq,i}$ (t_{CO2} /kWh) is the emission factor for fuel type i, f_i (%) is fraction of end-use electricity coming from fuel i and K is the number of fuels in the electricity mix. In particular, three greenhouse gases: (i) carbon dioxide (CO_2), (ii) methane (CH_4) and (iii) nitrous oxide (N_2O) are considered. According to the type of fuel (i.e. coal, diesel, natural gas, wind, nuclear, propane, solar, biomass, geothermal, etc.), GHG emissions are converted into equivalent CO_2 emissions (expressed in t_{CO2}) in terms of their global warming potential. In order to estimate the emission factor of each fuel type ($C_{eq,i}$), formula (1-20) is used.

$$C_{eq,i} = (e_{CO_2,i} + e_{CH_4,i} \times 21 + e_{N_2O,i} \times 310) \times \frac{0.0036}{n_i \times (1 - \lambda_i)} \tag{1-20}$$

In (1-20), $e_{CO2,i}$ (*kg/GJ*) is the CO_2 emission factor for fuel *i*, $e_{CH4,i}$ (*kg/GJ*) is the CH_4 emission factor for fuel *i*, $e_{N2O,i}$ (*kg/GJ*) is the N_2O emission factor for fuel *i*, n_i is the conversion efficiency ,in %, for fuel *i* and λ_i represents the fraction ,in %, of electricity lost in transmission and distribution for fuel *i*. The factor 0.0036 in (1-20) is used so as to convert kg/GJ into t_{CO2}/kWh. It can be seen from (1-20) that CH_4 and N_2O emissions are converted into equivalent CO_2 emissions by multiplying their emission factors with 21 and 310, respectively, since CH_4 is 21 times more powerful GHG than CO_2 and N_2O is 310 times more powerful than CO_2.

Formula (1-1) is extended to properly account for the cost of GHG emissions to cover the transformer losses throughout its lifetime, as per (1-21). TVL_e, *in $*, is the Total Value of Losses throughout the transformer lifetime incorporating the environmental cost (*CostGHG* - *$*).

$$TVL_e = TVL + CostGHG \tag{1-21}$$

The major differences among the referenced methodologies ([17] and [19]) rely on the calculation of the environmental cost term (*CostGHG*). According to [17], the environmental cost term should be calculated as per (1-22).

$$CostGHG = (\Delta E_{NLL} + \Delta E_{LL}) \times k \times C \times N \tag{1-22}$$

In (1-22), *N* is the transformer lifetime in years. In addition, C is considered constant throughout the transformer lifetime. It is important to note that the coefficient *k* defines how strong or weak the purchaser's (i.e., the electric utility) motivation is, in terms of investment to energy efficient transformers. This motivation is incorporated in the *TOC* evaluation method as a positive or negative cost, affecting the electric utility purchasing decision among the different manufacturer offers. Therefore, factor *k* reflects the importance accredited to the environmental impact during this decision. For instance, if *k*=0, then the electric utility does not take into account the environmental impact in the *TOC* formula and does not provide an incentive to the manufacturer to offer transformers with energy losses less than the energy losses of the reference transformer. On the contrary, if *k*=1, then the electric utility reinforces ($\Delta E_{NLL} + \Delta E_{LL} < 0$) or affects negatively ($\Delta E_{NLL} + \Delta E_{LL} > 0$) the purchasing decision by a factor equal to the environmental cost coefficient.

On the contrary, [19] accommodates IEEE Standard Method [3] to calculate the environmental cost (*CostGHG*). Following (1-12) and [19] the proposed loss evaluation method for transformers incorporating environmental cost is described in (1-23). $LECN_e$ is the levelized annual environmental cost of no-load loss, in \$/kW-yr, and $LECL_e$ is the levelized annual environmental cost of load loss in \$/kW-yr.

$$CostGHG = f_4(D,E) \times \Delta E_{NLL} + f_5(D,E) \times \Delta E_{LL}$$

$$\begin{aligned} f_4(D,E) &= \frac{LECN_e}{ET \times FCRT \times IF} \\ \Rightarrow LECN_e &= crf \times \sum_{j=1}^{N} C \times \frac{(1+GR_j)^j}{(1+d)^j} \end{aligned} \tag{1-23}$$

$$\begin{aligned} f_5(D,E) &= \frac{LECL_e}{ET \times FCRT \times IF} \\ \Rightarrow LECL_e &= crf \times \sum_{j=1}^{N} C \times \frac{(1+GR_j)^j}{(1+d)^j} \end{aligned}$$

1.5.3 Loss Evaluation Processes in Decentralized Electricity Markets

An initial step towards addressing a decentralized market-based loss evaluation technique, for evaluating the ownership cost of power transformers, is presented in [20]. Owing to deregulation, privatization and increased competition in electrical power systems, has revealed the importance of the correct financial and economical evaluation of project profitability in this area. The method has been developed by accounting for the energy loss consumption and its daily price fluctuation, revealing new aspects that must be taken into account during the definition of the transformer tender evaluation in modern electricity systems. The referenced method involves the incorporation of the discounted cost of transformer losses to their economic evaluation, providing the ability to account variable energy cost during the transformer lifetime.

Thus, the losses of power transformers in distribution network of a decentralized energy market environment may be capitalized by accounting different loss cost rates during peak and off-peak variable load hours, instead of a mean energy loss cost that is usually adopted in TOC methods. In addition to this, the method provides a means to a statistical and probabilistic assessment of the electricity price volatility.

The work in [20] demonstrates the application of the proposed idea using several electricity charging scenarios. In addition to these, the methodology incorporates a very important financial factor, the annuity factor (*AF – p.u*). This factor depicts the present value at a discount rate (*d*) of an annuity of 1$ paid at the end of each period *n* (PV_m). The referenced method is, more precisely, designed to appreciate the existence of TOU (Time-of-Use) electricity charging scheme in several energy systems (primarily decentralized market environments). Thus, [20] uses the generic formulation in (1-24).

$$TVL_y = \sum_{j=1}^{N}\left[\left(NLL_y(j) + LL_y(j)\right)\times\frac{EC_y(j)}{(1+d)^j}\right]$$
$$NLL_y = NLL \times h_y \times 365$$
$$LL_y = LL \times h_y \times 365 \times LF_y \quad (1\text{-}24)$$

In (1-24), *y* indicates the separate electricity cost charging periods (or TOU scheme periods), *EC* (*$/kWh*) is the energy cost applicable to period *y* for the evaluation year *j*, and h_y is the duration of an economic period in hours. It is important to note, that the sum of the different economic periods incorporated in a study (i.e. sum of h_y should not exceed the sum of the hours of a day).

Another step considered is that part of the referenced method accounts, also, for the hourly pricing variation of transformer loading, and thus of the amount of energy consumed by the transformer losses. This, in conjunction with the statistical and probabilistic assessment of energy price volatility and the transformer daily load curve, provides more realistic data, able to capture the uncertainties of price and load volatility in unpredictable energy market environments. In such unpredictable environments, [20] proposes the definition of *TOC* in the means of a histogram cost variation. Figure 1-3 illustrates an example case of a Total Ownership Cost variation for two size-adequate distribution transformers.

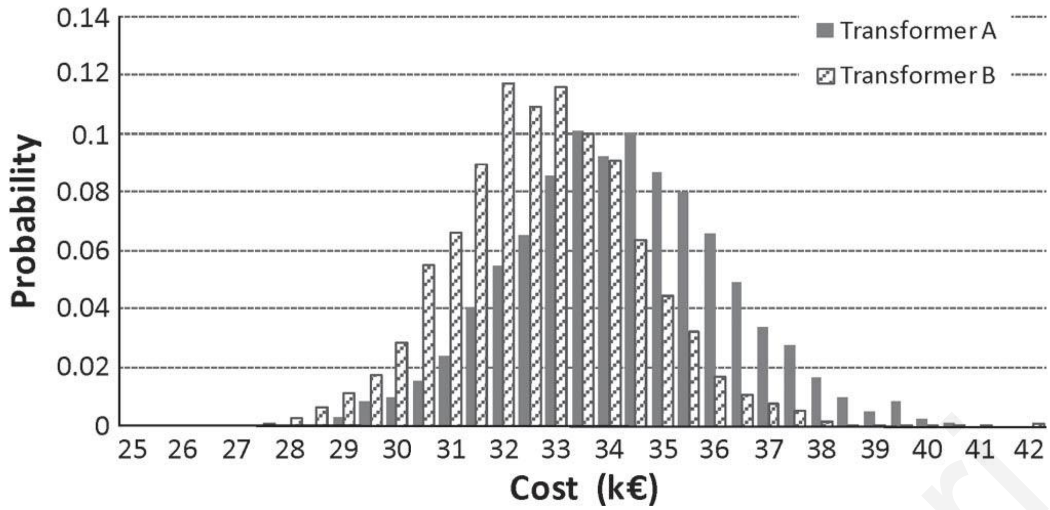


Figure 1-3: Example TOC Histogram Variation for Distribution Transformers [20]

The work in [20] concludes with the important statement: "More detailed representation of the daily energy price fluctuation results to more refined results considering the profits derived from the installation of energy efficient transformers and can therefore alter significantly the final purchasing decisions."

1.6 Critical Analysis of Existing Loss Evaluation Methods

1.6.1 Critical Evaluation of State of the Art Techniques

The loss evaluation methods found in the literature (Section 1.5) have significantly contributed in the development of this area throughout the years, especially during the last two decades. However, the majority of loss evaluation methods identified in literature refer to transformers that are to be placed, or already operate, in vertically integrated power systems. The latter means that the generation, transmission and distribution facilities are owned either by private regulated utilities or by public companies/ government agencies. A primary step for defining a transformer loss evaluation technique in a dis-integrated energy market was only identified in [20]. This method is related to a simplified market – based loss evaluation approach which nevertheless sets the benchmark for future development in this area.

An additional remark, highlighted in the literature is that the loss evaluation methods recognize that the perspective of the electric utility is different from the perspective of the industrial and commercial users of transformers. The identified transformer loss evaluation procedures for electric utilities involve understanding and assessing the total cost for generating, transmitting and distributing transformer losses throughout its lifetime. On the other hand, the identified procedures for capitalizing transformer losses owned by industrial/commercial users require an understanding and assessment of the electric rates that need to be paid to electric utility for meeting the transformer losses throughout its lifetime. Thus, the picture of transformers' loss economic evaluation, as it appears in literature, is summarized in Figure 1-4.

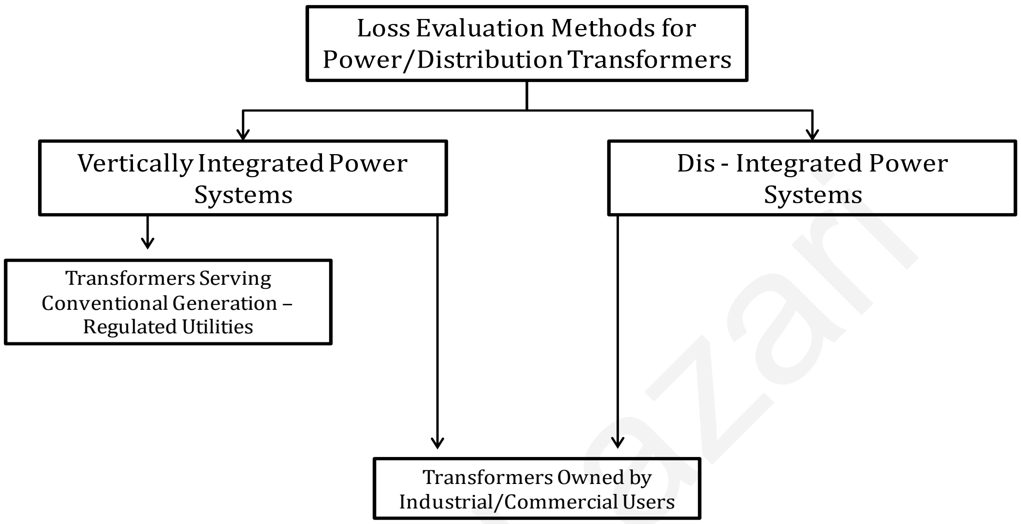


Figure 1-4: Picture of Transformers' Loss Evaluation as Identified in Literature

As it is easily extracted from the literature survey performed, the major difference amongst the existing loss evaluation methods relies on the economic processes followed and the economic perspective that applies to the interested party. The emerging transformers' loss cost rates ($f_1(D,E)$, $f_2(D,E)$ and $f_3(D,E)$) inherently reflect on the special circumstances of each transformer's load (i.e. commercial, industrial, domestic, etc.). This is achieved through the appropriate specification of the load factor (*LF*) and Loss Load Factor (*LLF*), the Peak Responsibility Factor (*PRF*) and the expected equivalent annual peak load (*PQE*) of the economically evaluated transformer.

As a final note, the methodologies identified in literature are recognized for their discretion to economically evaluate the cost of losses for, both, the cases of power and distribution transformers. The most important conclusion extracted is that, although the methodologies for capitalizing the losses of power/substation transformers are similar to those for distribution transformers, there are some minor differences among the approaches. The observed differences are:

1. If the case relates to power transformers, the method accounts only for generation and transmission networks costs (fixed and operating) only. The fixed and operating costs

of distribution systems are only incorporated for valuing the power losses of distribution transformers.

2. The cost of auxiliary power losses (power to serve transformers' cooling system, fans etc) is only considered for capitalizing the lifetime losses of power transformers.

1.6.2 The need to go forward

Given the new era of low carbon electricity markets and the increased penetration of intermittent energy sources (i.e. renewable energy sources – RES), a knowledge gap has been created in the transformers' techno-economic feasibility studies area. Owing to deregulation, privatization and competition, estimating the financial benefits of transformers investments and, in general, of electrical power systems are becoming increasingly important. Following the literature survey in combination to the newly introduced concepts in power electrical systems, the following problems have been identified:

1. Through the literature survey performed it was observed that the existing methods do not exactly appreciate for the discrete characteristics (operational and financial) between differently structured energy systems or utilities. The reason for this is that the referenced methodologies are not detailed enough so as to be easily customized to the particular needs of a system. They rely on approximations, estimations and figures that in most of the cases do not reflect the real/special circumstances that may apply for the proper loss evaluation of a transformer.
   In general, the loss evaluation processes are of immense importance in the power community, thus their detailed and transparent representation matters. The loss evaluation methods should be able to capture the specifics, both financial and loading, of the particular system in order to provide the most informed decision to the interested party. The latter triggers the need to develop transformers' evaluation processes that will be detailed enough, and under some modifications to be able to meet the specifics of the evaluated transformer/system.

2. As already been stated, the majority of published loss evaluation methods reflect on vertically-integrated systems where the generation, transmission and distribution facilities had been owned either by private regulated utilities or by public companies/government agencies. To this end, the existing loss evaluation

methodologies are incapable of capturing the correct specifics, both operational and financial, to reflect on the characteristics of a decentralized energy environment.

3. The picture of loss evaluations becomes more complex in the context of low carbon electricity markets. Loss evaluation methods should be adjusted for evaluating the ownership cost of transformers operated in a decentralized energy environment. For example, under liberalized electricity markets, several regulated utilities and independent power producers co-exist but have diversified ways of assessing their capital costs, system expenditures and generation profiles. Thus, the methods for capitalizing their own transformer power losses should be different. The methods identified in literature lag the capability of the proper unbundling of the demand and energy components of the cost of losses to the involved entities. This will, more importantly, ensure that each loss component is assigned to the appropriate party that may participate in a decentralized energy market, in terms of who is responsible to cover the transformer's losses.

4. An additional knowledge gap in transformers' loss evaluation methods, relates to transformers which are entitled to exclusively serve large renewable plants that participate in electricity markets. The challenges arise from the fact that these transformers are obliged to serve an intermittent energy source with varying operational and financial characteristics. Thus, the key element in capitalizing the losses of such transformers is to appreciate exactly how these losses should be evaluated, bearing in mind the intrinsic nature of renewable energy supply and the ownership status of the transformer in relation to the regulatory framework of the electricity market it exists in. Thus, capitalizing the losses of transformers serving intermittent energy sources triggers the need for revisiting the conventional loss evaluation methods.

1.6.3 Progress Beyond the State of the Art

The general motivation of this work is the proper revision and development of the conventional transformers' loss evaluation methods so as to account for the newly introduced concepts in electrical power world. This thesis provides transformers' loss evaluation methodologies which meet some of the needs that have arisen from the recent developments in modern power systems (see Section 1.6.2). To this end, the current picture of transformers' loss evaluation, as summarized in Figure 1-4, is enriched to the one illustrated in Figure 1-5. Figure 1-5 proposes that loss evaluation methods should be disintegrated so as to explicitly account for the regulatory framework of the system the transformer is operating in; Vertically Integrated Power Systems and Dis–Integrated Power Systems. Following these, loss evaluation methodologies are proposed to be categorized according to the source of the energy they are called to serve. The proposed statement is more clearly illustrated in Figure 1-5.

The main contribution of this work is to specifically formulate a number of key advancements over the classical loss evaluation formula (1-1) to account for the following circumstances: a) system specific loss evaluation method for transformers in vertically-integrated energy systems, b) system specific loss evaluation method for transformers in liberalized energy systems and, c) loss evaluation method for transformers explicitly serving Renewable Energy Source (RES) plants both in vertically-integrated and decentralized energy systems.

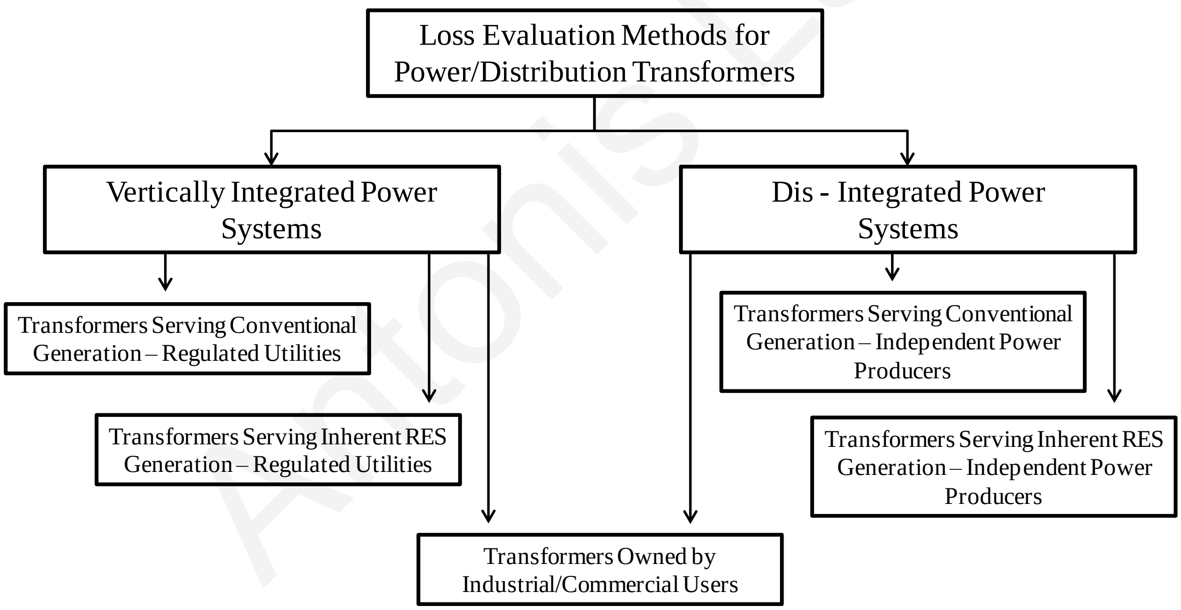


Figure 1-5: Subdivision of Loss Evaluations Method in Modern Power Systems

The specific topics that are thoroughly analyzed in this dissertation are listed below.

- **Loss Evaluation and Total Ownership Cost of Power Transformers in Vertically – Integrated Systems - A Comprehensive Method:** The key techniques employed in this study reflect on a more comprehensive and transparent method for calculating the cost of the electric power and energy needed to supply the life-cycle losses of power transformers. The method is applicable to transformer users who possess their own generation and transmission facilities. The proposed loss evaluation method is based on factors derived from relevant historical and forecasted data that are combined to determine the Total Ownership Cost (TOC) of power transformers. The proposed system specific method is evaluated on a small scale real system, by incorporating realistic financial data and system characteristics through appropriate techno-economic models as well as statistical evaluations. The calculated loss components of this study are compared to the methodology detailed in the IEEE C.57.120-1991.

- **Life-Cycle Loss Evaluation of Power Transformers Serving Large Photovoltaic Plants in Vertically Integrated and Decentralized Systems:** This part of work details a comprehensive loss evaluation method of power transformers serving large scale solar applications. The fact that these transformers are obliged to serve an intermittent energy source calls for a suitable method to evaluate their life-cycle losses and total ownership costs. These transformers may be owned by Independent Photovoltaic Power Producers (*IPP*) or by Regulated Utilities (*RU*). Thus, the method concurrently responds to the current efforts to address the concept of loss evaluation both in vertically-integrated and decentralized energy systems that are experiencing a high penetration of renewable energy.

- **Probabilistic Total Ownership Cost of Power Transformers Serving Large-Scale Wind Plants in Liberalized Electricity Markets:** This part of work proposes a probabilistic, life-cycle loss evaluation method to evaluate the TOC of power transformers that are obliged to exclusively serve large wind plants. The method introduced, responds to the ongoing efforts of developing risk and cost-based decision making processes in today's competitive and dynamic energy markets. Therefore, capitalizing the losses and consequently the ownership cost of transformers, serving intermittent wind energy sources, entails a probabilistic approach that integrates the financial and technical characteristics as well as the uncertainties of wind energy generation.

- **Contemplation of Loss Evaluation for Transformers Serving Large Renewable Energy Plants:** This part of work evaluates the available power transformers' loss evaluation methods both for vertically-integrated and decentralized energy systems that are experiencing a high penetration of renewable energy. In particular, this section attempts to constructively benchmark the PV specific and Wind specific, methodologies detailed in this work, over an equivalent ABB's online calculator that also attempts to integrate the specifics of renewable energy penetration.

1.6.4 Thesis Outline

This PhD thesis is outlined such as to highlight the way thoughts and research were built up throughout the course of this work. It is constituted by 6 Chapters, allowing the reader to easily deduce the steps followed over the course of the past years.

Chapter 2 is concentrated on a derived comprehensive loss evaluation method, applicable to power transformer users who possess their own generation and transmission facilities in a regulated energy system. The proposed method is based on system-specific factors (operational and financial) derived from the relevant historical and forecasted data. The major advancement of the method in Chapter 2 is the discrete derivation of the demand (*D - $/kW*) and energy (*E - $/kWh*) cost of losses for the specifics of the generation and transmission (and where applies, distribution) categories.

Extending the area of transformer loss evaluation to account for the increased RES penetration, the methodology in Chapter 2 is specifically modified to accommodate the specifics of a power transformer serving a large-scale photovoltaic (PV) plant. Thus, Chapter 3 is related to a loss evaluation method of a power transformer serving a large-scale PV application in vertically integrated and decentralised energy systems. To this extend the demand and energy components of losses are properly unbundled, and in conjunction to a PV plant's characteristics (operational and financial), a methodology understanding the implications of a transformer serving a PV plant is proposed, both for Independent Power Producers (*IPP*) and Regulated Utilities (*RU*).

Moreover, some key modifications were in turn needed to account for an appropriate loss evaluation method of transformers serving other renewable energy sites. This is because the energy generation profile and characteristics of a PV plant for example, are very different to the specifics of a Wind Farm. Thus, Chapter 4 is related to a probabilistic TOC approach for power transformers serving large-scale wind plants in liberalized electricity markets.

Chapter 5 provides a contemplation of the main available transformer loss evaluation methods, both, in vertically integrated and decentralized energy systems. It is, mainly, related to the important methodologies found in literature and their significance in respect to the thesis' proposed work. More importantly, Chapter 5 provides a benchmark of the current efforts to address the concept of loss evaluation in energy systems that are experiencing a high penetration of renewable energy sources. The thesis is concluded in Chapter 6 where the main conclusions and the contributions of this work are presented, together with some thoughts about future steps in this area.

2

Loss Evaluation and Total Ownership Cost of Power Transformers in Vertically-Integrated Systems: A Comprehensive Approach

2.1 Introduction

2.1.1 General Remarks

The main objective of this chapter is to provide a comprehensive method for calculating the cost of the electric power and energy needed to supply the life-cycle losses of power transformers in a vertically-integrated energy system. It is noted that the illustrated method is applicable to power transformer users who possess their own generation and transmission facilities.

Within this chapter, the comprehensive system-specific method is evaluated on a small scale real system, by incorporating realistic financial data and system characteristics through appropriate techno-economic models as well as statistical evaluations. The calculated loss components of this study are compared to the methodology detailed in the IEEE C.57.120-1991 [3].

2.1.2 Advancements of the Proposed Method beyond the State of the Art

The proposed method relates in firming the loss evaluation endeavour by providing a method that embraces both capital and transformer user's operating expenditures in costing the power to supply life cycle losses of power transformers. One of the main advancements of this method is the ability to identify and weight any associated operating costs to a corresponding demand (*D - $/kW*) and energy (*E - $/kWh*) component of losses by defining "weighted multiplying factors". The procedure, as this will be described in the subsequent sections, follows the procedure outlined below:

a) The proposed method incorporates system specific historical data to correlate the operating costs to the corresponding demand and energy component of losses. The historical data include the operating costs per system's category (generation and transmission), the maximum demand (*MW*) during the previous years and the system energy requirements (*MWh*), all for the same period in the past. To this end, the methodology identifies and weights an appropriate set of incremental demand and energy components of the cost of losses.

b) In life-cycle loss evaluations it is imperative to rely on forecasts of escalated energy related prices, over the expected life-cycle of new power transformers. Thus, a formulation to incorporate the projected energy prices as per the specific fuel used (or would be used) in the generation mix of the system (to supply the energy used by the losses) over the life-cycle of the transformer under study is utilised. The suggested approach deviates from the IEEE C57.120-1991 method, where constant escalation rates are employed to determine the future energy values over the life cycle of the transformer under study.

Moreover, the proposed concept incorporates system specific forecasted data to specifically account for the fuel/energy related demand and energy component of losses. The forecasted data include, both, fuel price related data and system operating expenses. More precisely, the proposed method incorporates forecasted fuel prices (for the fuel mix used or to be used during the transformer's useful life), forecasted maximum system demand requirements (*MW*) and the estimated energy requirements throughout the transformer's evaluation lifetime.

2.2 Theoretical Discussion of Proposed Method

In the context of this chapter a "system" includes all power related facilities from generation down to transmission level. If losses are seen as a load to the system it is apparent that sufficient system capacity is required to accommodate the peak load and the associated losses. The installed capacity is determined by the system's peak demand including its peak load losses. There are two main system categories that can benefit from system capacity investments over the life cycle of new power transformers: Generation (*G*) and Transmission (*T*). Since load losses occur primarily at peak load periods, it is required to determine the impact a change in losses would have, on the peak demand of each category the change affects, over a future evaluation period. Hence, the costs of the additional capital and other fixed expenditure sized to supply the power used by the losses (coincident with the peak demand) over the life cycle of a power transformer, constitute the demand component of losses (*D*).

However, the Total Value of Losses (*TVL*) evaluation (2-1) comprises both a demand component (*D*) and an energy component of losses (*E*).

$$TVL = CostNLL + CostLL + CostAUX$$

$$\begin{aligned} CostNLL &= f_1(D,E) \times NLL \\ CostLL &= f_2(D,E) \times LL \\ CostAUX &= f_3(D,E) \times AUX \end{aligned} \qquad (2\text{-}1)$$

Energy charges are based on the average incremental cost of delivered power as obtained from generation units that are entitled to pick-up the load. Hence, the energy component of the cost of losses comprises the variable costs of generating the additional energy consumed by the losses over the life cycle of a power transformer. Both demand and energy components should be calculated for all affected system categories (e.g. generation and transmission), over the life cycle of power transformers evaluated. Therefore, the two components are appropriately annuitized (i.e. levelized) to provide a total cost figure *($/kW*) as per the generic illustration (2-1), i.e. the Total Value of Losses *(TVL - $).*

The calculated *TVL* accounts for the sum of the present worth of each kilowatt of loss (*NLL*, *LL*, *AUX*) as a function of the *D* and *E* components over some future evaluation period. The Total Ownership Cost (*TOC)* of transformers is therefore defined by the purchase price (*PP*) of the transformer plus the *TVL* (2-1).

2.2.1 Definition of Demand and Energy Components of Losses

For the purpose of this chapter the Demand (*D*) and energy (*E*) components of the cost of losses are categorized and defined as follows:

a) Generation Category – Demand Component – (D_{g_peak} - $/kW):

The annual fixed cost (associated with the generation category's related expenses) required to serve a kW of loss occurring at the time of the system's peak demand.

b) Transmission Category – Demand Component – (D_{t_peak} - $/kW):

The annual fixed cost (associated with the transmission category's related expenses) required to serve a kW of loss occurring at the time of the system's peak demand.

c) Generation Category – Energy Component – (E_{g_peak} - $/kWh):

The annuitized variable cost (associated with generation category's related expenses) required to serve the energy consumed by the losses occurring at the time of the system's peak demand, over the life cycle of a power transformer.

d) Transmission Category – Energy Component – (E_{t_peak} - \$/kWh):

The annuitized variable cost (associated with transmission category's related expenses) required to serve the energy consumed by the losses occurring at the time of the system's peak demand, over the life cycle of a power transformer.

2.3 Capital and Operating Costs

Both capital and operating expenditures of a system represent the use of human and material resources. Therefore they should be included in the total costing of supplying any losses (coincident with system's peak demand) over the life-cycle evaluation of power transformers. The capital (fixed) expenditure should be associated with the demand (*D*) component of the cost of losses whereas the operating expenditure may be associated both with the demand and the energy (*E*) component of the cost of losses as will be further discussed.

For example, capital expenditures may include investments on a) new peaking generation installations per kW and b) transmission system installations per kW. Examples of substantial operating costs that could be of relevance to the *TVL* evaluations are tabulated in Table 2.1.

Table 2.1
Nomenclature

Capital Costs	Operating Costs
New Peaking Generation Installation (G)*	Operation (G, T)*
Transmission System Fixed Costs (T)*	Repairs &Maintenance (G, T)*
	Green House Emissions Rights (G) *
	Fuels (G)*
	Other (G,T)*
* G: Generation Category, T: Transmission Category	

The loss evaluation method proposed in this chapter suggests that any relevant operating costs should be apportioned in the main systems' categories involved (i.e. generation and transmission), as shown in Table 2.1. Consequently, both demand and energy components should be evaluated according to any relevant capital and operating costs classified under the expenses of generation and transmission categories respectively. This provides the means to account for the cumulative effect that a change in losses would progressively have in these two categories. For example a loss increase in transmission level, at the time of system's peak demand, would impact on the cost per kW of a) the planned additional peaking generation capacity and b) any other associated capital and operating expenditure, from generation down to transmission category - where the loss change takes place.

2.3.1 Financial Factors

Since the loss evaluation should take into account the present worth of the future variation of any associated costs, a further element that needs to be properly defined is the discount rate (*d*). It is thus the minimum acceptable rate of return from an investment and as such it should be above the interest rate which applies to the overall objectives of the business. It is proposed that an appropriate real discount rate should be based on the interest rate paid by the business (e.g. system's users) in the last 5 years. Moreover, the related literature [21], [22] recommends that the minimum required real discount rate, incorporated in loss evaluations, should be about 2% higher than the actual interest rate paid by the business. This is because the minimum return, necessary to justify spending optional capital, requires judgment that should take into account incentive, risk, opportunity cost, and accountancy procedures [23]. A real discount rate (*d*) should be utilised to determine the present worth factor (pw_j – *p.u*) (1-4) and the capital recovery factor (crf_j – *p.u)* (1-10). The present worth multiplier is the factor that determines the present worth of future costs. The capital recovery factor (crf_j) is the multiplier that when applied on the sum of *j* annual present worth costs will yield the equivalent uniform equal amount for *j* years. In this way a levelized cost (see Section 1.4) is determined, i.e. an equivalent levelized annual cost which takes into account future costs variations.

2.4 Fuel Related Costs

Energy costs are comprised of fuel costs and any other energy related operating expenditure (e.g. Operation, Repairs and Maintenance). Life-cycle loss evaluations of power transformers, inevitably depend on future energy related price estimates. In this chapter, the method to address this need primarily relies on:

a) Forecasts of the system's energy requirements (*MWh*).
b) Forecasts of the system's maximum demand requirements (*MW*).
c) Forecasts of the relevant fuel prices (*$*) - over the life-cycle of the power transformers.

The required forecasts should cover the life-cycle of the evaluated power transformers.

The forecasted energy requirements (*UG – MWh or GJ*) per transformers' life-time year (*j*) result (2-2) in forecasted fuel consumptions (*FuC – Metric tons (MT)*) by incorporating appropriate Net Calorific Values (*NCV – GJ/MT*) and generating units' efficiencies (n_{ef} *- % or p.u*) - as per the fuel type (*i*) used. At this point, it should be noted that the efficiency of a generating unit may not be constant; but in fact associated to a) the amount of MW being generated and b) type of combustion cycle. As an approximation an annual average efficiency (n_{ef}) value is assumed in (2-2). *FN* denotes the number of different fuels used in the electricity generation mix while *N* denotes the life-cycle, in years, of the transformer evaluated.

$$FuC_{i,j} = \sum_{i=1}^{FN} \sum_{j=1}^{N} \frac{UG_{i,j} / NCV_i}{n_{ef\,i}} \tag{2-2}$$

Hence, the forecasted fuel consumption (FuC_i) per year *(j)* is subsequently combined with the annual forecasted cost of each individual fuel (*FFP - $/MT*) to obtain a total future fuel cost (*FC - $*) as proposed in (2-3).

$$FC_{i,j} = \sum_{i=1}^{FN} \sum_{j=1}^{N} FuC_{i,j} \times FFP_{i,j} \tag{2-3}$$

2.5 Weighted Multiplying Factors

2.5.1 Allocation of Weighted Factors to Capital and Operating Costs

As already reported, the demand component of the cost of losses should comprise all capital related expenditure sized to supply the power used by the losses at the time of system's peak demand. It is further proposed that the demand component of the cost of losses should also embrace some portion (i.e. a percentage that is classified as a fixed cost) of any relevant operating expenditure (e.g. repairs and maintenance). This fixed cost portion (Figure 2-1) should be added to the demand component of the cost of losses. The remainder portion (i.e. the variable costs of the operating expenditure considered) should be added on the energy component of the cost of losses. The energy component should embrace all variable costs (Figure 2-1) that are a function of the energy units consumed.

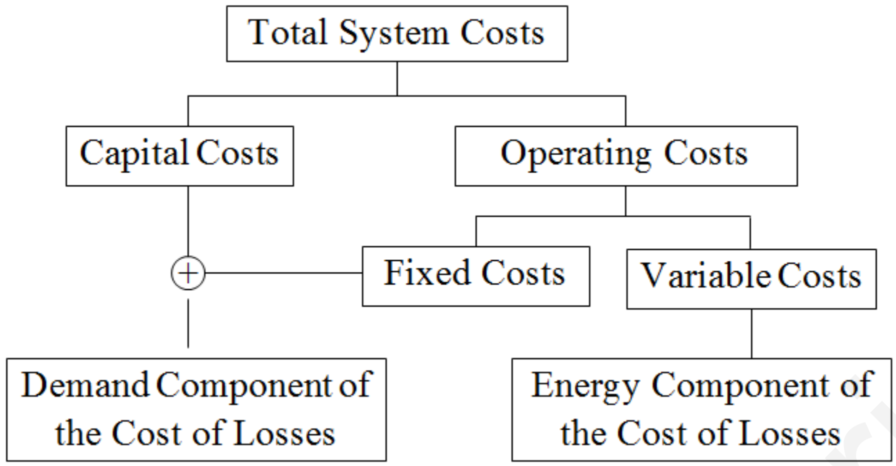


Figure 2-1: Expenditure Allocation to Demand and Energy Components of the Cost of Losses

As far as possible it is suggested to use constant percentages, derived from historical system's operation data to allocate an operating expenditure to a corresponding demand (*D*) and energy (*E*) component of the cost of losses. These percentages should be kept under review, particularly when there is a substantial change in the plant's mix and/or capacity/loading factor.

The latter can be realized by adopting the "screening curve" approach [24]. Screening curves (Figure 2-2) can be used to allocate a percent fixed (demand - D) component and a percent variable (energy - E) component to a particular operating cost item. This allocation can be a function of the system's capacity factor ($CF - p.u$) - or alternatively the load factor ($LF - p.u$).

A generic mathematical representation of the screening curve illustrated in Figure 2-2 is given by (2-4) [24]. It represents the tabulated total costs of a particular operating cost item (e.g. operation or repairs and maintenance per year) as a function of the plant's capacity factor (*CF*) over the past years.

$$TC = DC + CF \times EC \tag{2-4}$$

TC represents the yearly total operating costs (e.g. operation total costs), *DC* represents the corresponding demand (fixed) related costs, *EC* represents the corresponding energy (variable) related costs and *CF* represents the yearly capacity factor of the system under study.

As detailed in [24] the demand (fixed) cost *DC* is a constant flow of cost that when added to the energy (variable) cost *EC* will provide the total costs *TC* e.g. the annual revenue requirements. Of course, this assumes a unity capacity factor *CF*. If *CF* is less than unity, *EC* will be reduced proportionally. However, *DC* remains unaffected because the capital cost to serve the demand must be paid irrespective if it is used or not. That explains why *DC* is termed as a fixed cost.

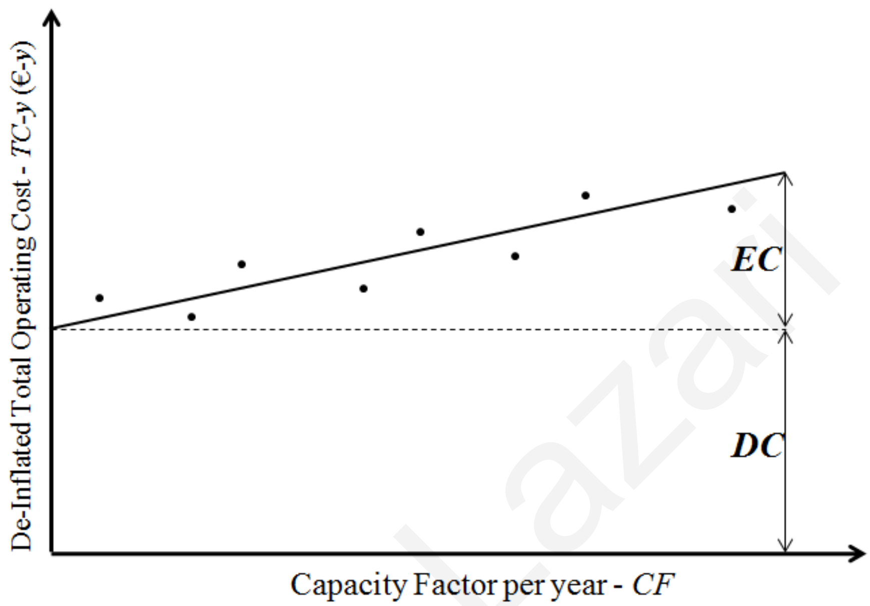


Figure 2-2: Use of screening curves to estimate demand and energy components weight factors [24]

By moving further to divide each term of (2-4) by *DC* and inverting it, in order to obtain a percent weight factor for the *DC* as a function of the system's load factor *LF*, the percent weighted demand factor of the operating cost item under study (cc_{cost_item} – *% or p.u*) is obtained (2-5). Conversely, the percent weight factor for the energy component (ec_{cost_item} – *% or p.u*) is, also, given in (2-5).

$$\begin{gathered} cc_{cost\_item} = \frac{DC}{TC} = \frac{1}{1+\varepsilon\times\tau\times LF} \\ ec_{cost\_item} = 1 - cc_{cost\_item} \\ \Rightarrow \varepsilon = \frac{EC}{DC}, \tau = \frac{CF}{LF} \end{gathered} \tag{2-5}$$

2.5.2 Allocation of Weighted Factors to Fuel Costs

There is one special case, namely the cost of fuels, where further investigation is needed to allocate an appropriate set of weight factors. The cost of fuels should not be in total allocated to the energy component (*E - $/kWh*) of the cost of losses, because part of the fuel is consumed in meeting the "zero load" losses. In the context of this study, the zero load losses are taken to depend on the type and size of the generating plant and therefore should be related to the demand component (*D - $/kW*) of the cost of losses. Therefore, a rigorous method is adopted (2-6) that characterizes the actual fuel consumption (*AFC – metric tons (MT)*), on a per year basis, that takes place in a plant.

$$AFC = TSU \times INFR + RH \times ZRFL \tag{2-6}$$

Where *TSU* is the aggregate amount of "Sent Out" units (*MWh/yr*) from system's machines burning a particular fuel per year, *INFR* is the machines' corresponding incremental fuel rate (*MT/MWh*), *RH* is the sum of machines running hours burning the same fuel per year (*hours/yr*) and *ZRFL* is the machines' corresponding zero load fuel rate (*MT/hour*). More in depth, *ZRFL* is the fuel consumption of the machine running at full speed but not synchronized to the system. It, basically, covers:

a) Thermal losses – depended on temperature and pressure which are substantially constant regardless of load.
b) Steam consumption – to supply the friction and windage losses of the machines.
c) Power consumption of auxiliaries (e.g. boiler fans, CW pumps etc.).
d) Power consumption of general auxiliaries (e.g. air compressors, station lighting etc.).

It should be highlighted, though, that the actual fuel consumption calculation as given in (2-6), is an approximation. The fuel consumption is not necessarily a linear combination of the incremental cost (*INFR)* and the zero load fuel rate (*ZRFL)*. Some combustion and steam units tend to have a very non-linear cost vs. load characteristic, especially steam units that have multiple control (steam admission) valves.

Following (2-5) and (2-6), the demand (cc_{fuel} *– % or p.u*) and energy (ec_{fuel} *– % or p.u*) component percent weight factors of the total fuel cost for the plants machines can be calculated using (2-7).

$$cc_{fuel} = \frac{F \times ZRFL}{E \times INFR + F \times ZRFL}$$
$$ec_{fuel} = 1 - cc_{cost\_item}$$
$$\Rightarrow F = \frac{\sum_{j=1}^{N} RH_j}{N}, E = \frac{\sum_{j=1}^{N} TSU_j}{N} \tag{2-7}$$

In (2-7), F (*hours*) is the average of the sum of running hours of all machines in the period under study (N years) and $ZRFL$ is the calculated average zero load fuel rate. Moreover, E (*MWh*) is the average of the "sent-out" energy units in the period under study (N years) and $INFR$ is the incremental fuel rate.

2.5.3 Allocation of Size Factors

At this point, it is important to highlight the need to determine the impact a change in losses, at the time of system's peak demand, would have on future system additions. The evaluation of the demand cost component of incremental losses is difficult because small changes in peak load have an uncertain effect on future generation or transmission capacity additions [14], [15]. Therefore, this proposed loss evaluation method has incorporated the suggestion of [25] which considers that a change in losses will not affect the scheduling of new facilities but may affect their size. The recommendation is that the demand component of losses should be evaluated at the incremental cost of increasing the size of planned facilities which is typically two thirds of their average cost. Following this suggestion, the size factor is directly affecting the percent weighted demand factor of the operating cost item/fuel under study. Thus, for transmission category the size factor $SFcc_t$ = 2/3 is generally assumed. For the generation category (2-8) should be used:

$$SF_{cc_g} = \frac{2}{3} \times (1 + RM) \tag{2-8}$$

Where, RM is the p.u. reserve margin of the generation capacity. The evaluation of the size factor basically suggests that the existing installed capacity is such that can limit the calculated demand component of losses (D - $/kW) for planned facilities by the determined size factor of each category.

2.6 Demand Component of Losses' Cost Calculation

It is reiterated that the costs of the capital and other fixed expenditure appropriately sized to supply the power used by the losses (at the time of system's peak demand) over the life cycle of a power transformer constitute the demand component of losses.

2.6.1 Demand Component Attributed to Operating Costs

The operating costs equivalent demand component (*D - $/kW*) should be based on historical data describing all relevant operating costs of the system. A further data required for this evaluation is an inflation rate for the years data are available. Once the relevant historical costs are obtained and classified per system's category (*Generation – G*, *Transmission – T*), these are associated to the system's maximum demand (*MW*) of each year considered throughout the transformer useful life. The operating costs are then adjusted to consider the inflation of each corresponding year. Each de-inflated cost item is plotted against the system's maximum demand (*MW*) of each corresponding year as illustrated by Figure 2-3. By assuming that a linear relationship exists a straight line is then fitted (2-9) on the plotted points by using the method of least squares.

$$y = \alpha \times P + \beta \tag{2-9}$$

It is then possible to extract, α - *$/MW*. This figure, α - *$/MW*, is basically a constant increase of the relevant operating cost per *MW*, as derived from the historical data available. By determining, α (*$/MW*), it can be therefore assumed that there will exist a similar future projection of the relationship that describes the operating cost item under study (y - *$*) and the system's demand (P - *MW*), over the life cycle of the transformer under study.

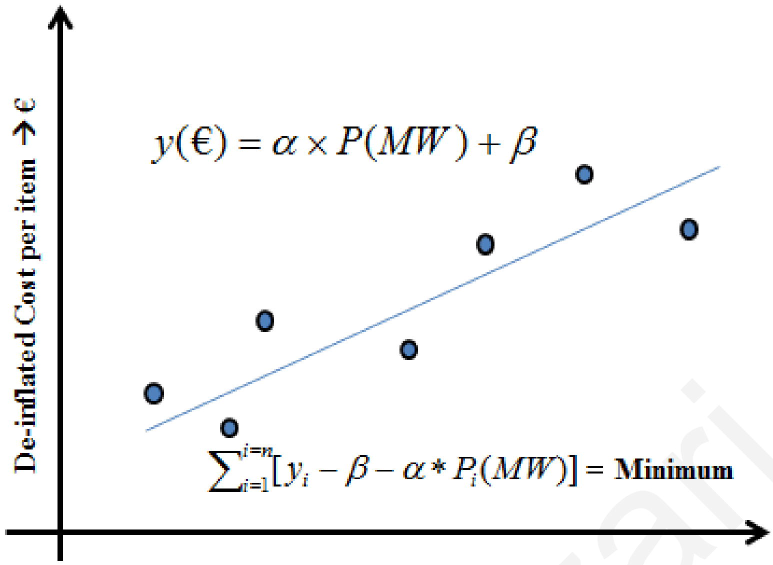


Figure 2-3: Annual Demand Component for Operating Costs

This assumption is valid provided that no extraordinary conditions of system growth or recession will occur in the immediate future. Therefore the demand component of losses attributed to the associated operating costs can be summarized on a per item (n) basis for generation (2-10) and transmission (2-11) categories related costs respectively:

$$D_{g_{OP\_item\_n}} = \alpha_{g\_item\_n} \times cc_{cost\_item\_n} \times SFcc_g \tag{2-10}$$

$$D_{t_{OP\_item\_n}} = \alpha_{t\_item\_n} \times cc_{cost\_item\_n} \times SFcc_t \tag{2-11}$$

Where $D_{g\ op\_item\_n}$ and $D_{t\ op\_item\_n}$ are the annual demand components of the cost losses, in *$/kW*, for each relevant operating expenditure for generation category and transmission category respectively. Moreover, $\alpha_{g\_item\_n}$ and $\alpha_{t\_item\_n}$ are the incremental costs per MW (*$/MW*), obtained as per the method illustrated by Figure 2-3. The $cc_{\_cost\_item\_n}$ is the weighted multiplying factor for the demand component for each operating cost considered, as defined in Section 2.5.1. $SFcc_g$ and $SFcc_t$ are the size factors as defined in Section 2.5.3.

2.6.2 Demand Component Attributed to Fuel Costs

As already discussed, the cost of fuels should not be in total allocated to the energy component of the cost of losses, because part of the fuel is consumed in meeting the “zero load” generation losses (2-7) which is related to the demand component of the cost of losses. Figure 2-4 illustrates the forecasted peak demand ($P_{Forecasted}$ - *MW*) and the forecasted fuel prices *FC* -

*$* (2-3) as per the system's needs over the life cycle of the transformer under study. Therefore, the annual demand component that accounts for the fuel costs (D_{gfuel} - *$/kW*) is given by (2-12).

$$D_{g_{fuel}} = \alpha_F \times cc_{fuel} \tag{2-12}$$

Where α_F is the incremental cost per MW of fuels (*$/MW*), as obtained by the method of least squares, and cc_{fuel} is the demand component percent weight factor for fuels as expressed in (2-7).

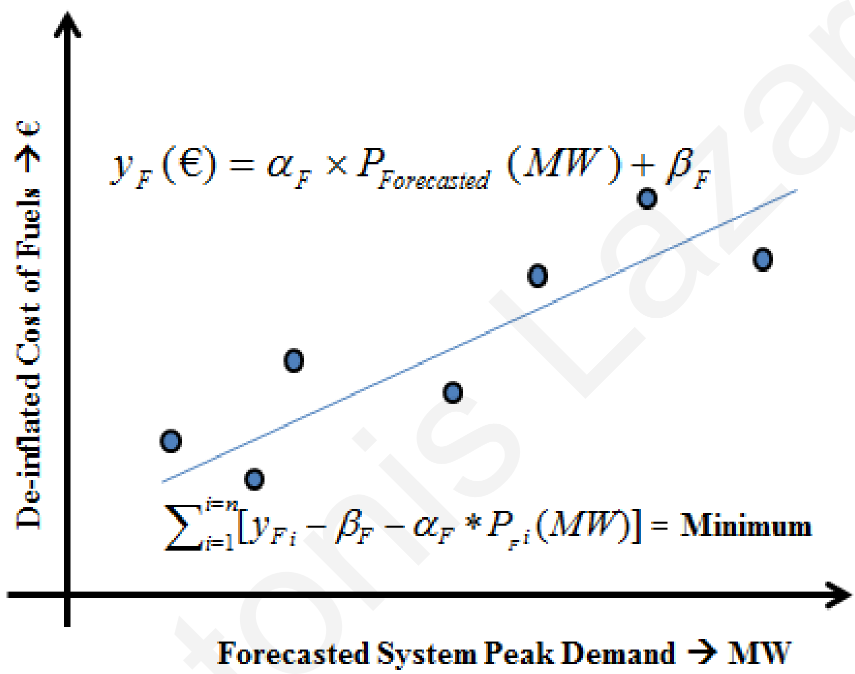


Figure 2-4: Annual Demand Component for Fuel Costs

2.6.3 Aggregate Demand Component of Losses

The demand component of the cost of losses for each category is then obtained for generation (2-13) and transmission category (2-14).

$$D_{g\_peak} = ACPG + D_{g_{fuel}} + \sum_{n=1}^{j} D_{g_{OP\_item\_n}} \tag{2-13}$$

$$D_{t\_peak} = ACTS + \sum_{n=1}^{j} D_{t_{OP\_item\_n}} \tag{2-14}$$

ACPG (2-15) is the annuitized cost per *kW* (*$/kW*) of planned peaking generation units and *ACTS* (2-16) is the annuitized cost per *kW* (*$/kW*) of transmission system installations required to meet the system's increasing losses at the time of system's peak demand.

$$ACPG = SFcc_g \times C_{PG} \times crf_N \tag{2-15}$$

$$ACTS = SFcc_t \times C_{TS} \times crf_N \tag{2-16}$$

Where C_{PG} and C_{TS} are the costs per *MW* (*$/MW*) of any planned peaking generation units and transmission system installations respectively, crf_N (1-10) is the capital recovery factor over the *N* years of evaluation and $SFcc_g$ and $SFcc_t$ are the size factors that limit the calculated demand component of losses for the planned generation and transmission facilities respectively.

Consequently for evaluating the *TVL* of new power transformers installed at transmission level the aggregate annuitized demand component of losses is given by (2-17).

$$D_{PEAK} = D_{g\_peak} + D_{t\_peak} \tag{2-17}$$

2.7 Energy Component of Losses' Cost Calculation

The energy component of the cost of losses comprises the variable costs of generating the additional energy consumed by the losses over the evaluation period considered. These costs are evaluated according to a) the fuel usage and prices of the planned peaking generating units and b) any variable operating costs (energy related) per *kWh* over the life cycle of the power transformer under study.

2.7.1 Energy Component Attributed to Operating Costs

Once the system's historical energy related operating costs are obtained and classified per category, these are associated to the system's energy generation (*MWh*) of each corresponding year. The costs are then adjusted to consider the inflation of each year considered. Consequently, for each year the ratio ($/MWh) of the de-inflated costs (*$*) to the total energy generated (*MWh*) per year is determined and subsequently associated to each corresponding year. That is the ratio (*$/MWh*) of the de-inflated costs to the total energy generated per year is plotted against each corresponding year as illustrated by Figure 2-5.

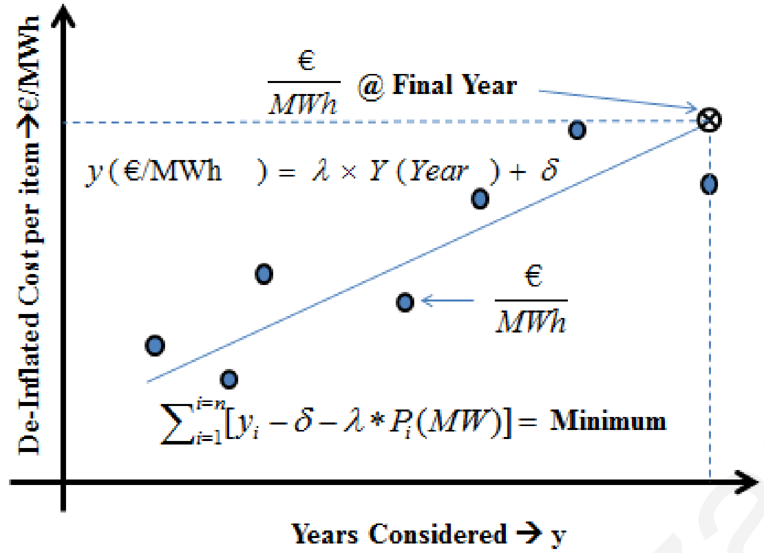


Figure 2-5: Annual Energy Component for Operating Costs

By assuming that a linear relationship holds, a straight line is then fitted (2-18) on the plotted points by using the method of least squares.

$$y = \lambda \times Y + \delta \tag{2-18}$$

However, in order to associate the calculated energy component of the cost of losses towards the latest operating costs and to a lesser extent towards costs valid in previous years, *y* (*$/MWh*) is calculated for the latest year for which data is available, i.e. *Y=latest_year* that data is available. The terms λ and δ in (2-18) are as determined by the least square method applied.

Therefore the annual energy component of losses calculation is summarized per operating cost for generation (2-19) and transmission (2-20) categories related costs respectively.

$$E_{g\,op\_item\_n} = \left(\lambda_{g\_item\_n} \times Y(Latest\_Year) + \delta_{g\_item\_n}\right) \times ec_{item\_n} \tag{2-19}$$

$$E_{t\,op\_item\_n} = \left(\lambda_{t\_item\_n} \times Y(Latest\_Year) + \delta_{t\_item\_n}\right) \times ec_{item\_n} \tag{2-20}$$

Where $E_{gop\_item\_n}$ is the annual energy component of the cost of losses of each relevant operating cost classified under generation category and $E_{top\_item\_n}$ is the annual energy component of the cost of losses of each relevant operating cost classified under transmission category. $\lambda_{g\_item\_n}$ and $\lambda_{t\_item\_n}$ are the incremental costs per *MWh* (*$/MWh*), obtained as per the method illustrated by Figure 2-5 for generation and transmission categories respectively.

ec_{item_n} is the percent weighted multiplying factor for the energy component assigned to each operating expenditure considered, as defined in Section 2.5.1.

2.7.2 Energy Component Attributed to Fuel Costs

In this case, it is again necessary to incorporate the forecasted system's energy requirements (UG) and the subsequent fuel consumption (FuC) as discussed in Section 2.4. The annuitized energy component attributed to escalated fuel prices as per the forecasted fuel prices and usage (E_{gfuel} - $/MWh$) is summarized by (2-21).

$$E_{g_{fuel}} = \sum_{j=1}^{N} \left[\frac{ec_{fuel} \times FC_j}{UG_j} \times pw_j \right] \times crf_N \qquad (2\text{-}21)$$

Where FC_j (2-3) is the overall de-inflated fuel costs ($\$$) allocated to energy per year, ec_{fuel} is the percent energy component weight factor for fuels, UG_j is the system's forecasted MWh units generated per future year, pw_j is the present worth factor per year, crf_N is the capital recovery factor and N is the evaluation period (years). Figure 2-6 illustrates graphically the process of calculating the annuitized energy (E_{gfuel}) component attributed to varying fuel prices over the life-cycle of the power transformer evaluated, as per the fuel mix considered.

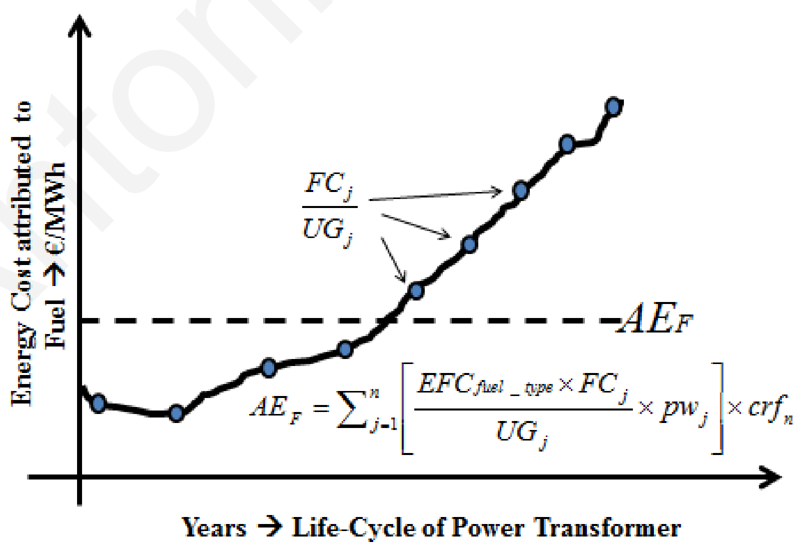


Figure 2-6: Annual Energy Component for Fuel Costs

2.7.3 Aggregate Energy Component of Losses

The energy component of losses reflecting on all energy related costs is given for generation category (2-22) and transmission category (2-23).

$$E_{g\_peak} = E_{g_{fuel}} + \sum_{n=1}^{j} E_{g_{op-item\_n}} \tag{2-22}$$

$$E_{t\_peak} = \sum_{n=1}^{j} E_{t_{op-item\_n}} \tag{2-23}$$

For evaluating the *TVL* of new power transformers (i.e. installed at transmission level) the aggregate annuitized energy component of losses is given by (2-24).

$$E_{PEAK} = E_{g\_peak} + E_{t\_peak} \tag{2-24}$$

2.8 Proposed TVL of Power Transformers

With reference to the generic illustration of *TVL* in (2-2), it is proposed that the total cost of losses for new power transformers installed at transmission level should be evaluated as per (2-25). Reiterating from Chapter 1, $f_1(D,E)$ is the evaluated annual loss cost rate (*$/kW*) for transformer's no-load losses, $f_2(D,E)$ is the evaluated annual cost rate (*$/kW*) for transformer's load losses and $f_3(D,E)$ is the evaluated lifetime annual (*$/kW*) for transformer's auxiliary power losses. Tables 1.1 and 2.2 tabulate the further particulars of the nomenclature used in (2-25).

$$\begin{gathered} TVL = CostNLL + CostLL + CostAUX \\[1em] CostNLL = N \times f_1(D,E) \times NLL \\ CostLL = N \times f_2(D,E) \times LL \\ CostAUX = N \times f_3(D,E) \times AUX \\[1em] \Rightarrow f_1(D,E) = D_{BASE} + 8760 \cdot AF \cdot E_{BASE} \\ \Rightarrow f_2(D,E) = D_{PEAK} \cdot PRFS^2 \cdot PQD^2 + 8760 \cdot LLF \cdot E_{PEAK} \cdot PQE^2 \\ \Rightarrow f_3(D,E) = D_{PEAK} + 8760 \cdot FOW \cdot E_{PEAK} \end{gathered} \tag{2-25}$$

Table 2.2
Nomenclature

NLL (kW)	No Load Losses of Transformer
LL (kW)	Load Losses of Transformers
AUX (kW)	Auxiliary Losses of Transformers
PRFS (p.u)	Peak Responsibility Factor of Transformer [14]
PQD (p.u)	Levelized Annual Peak Load of Transformer as per its life-cycle, for Demand Component. [14]
PQE (p.u)	Levelized Annual Peak Load of Transformer as per its life-cycle, for Energy Component. [14]
LLF (p.u)	System's Loss Load Factor [14]
FOW (p.u)	Average hours per year the transformer cooling is operated
AF (p.u)	Availability Factor, the proportion of time that a transformer is predicted to be energized

Three terms are present in (2-25), namely the no-load cost of losses (*CostNLL - $*), the load cost of losses (*CostLL - $*) and the load loss auxiliary cost (*CostAUX - $*). It is apparent that each type of loss is evaluated as per its demand and energy component ($f_1(D,E), f_2(D,E), f_3(D,E)$ - *$/kW*). However, these components should be evaluated separately for peaking generation and base generation units. The demand ($D_{BASE,}$) and energy (E_{BASE}) cost components of the no-load losses (*NLL*) should be evaluated according to the related costs and energy for base load generation [14]. In contrast, the demand (D_{PEAK}) and energy (E_{PEAK}) cost component of the load losses (*LL*) should be evaluated according to the related costs and energy for peaking generation. Furthermore the load loss term (*LL*) is separated into its demand and energy component by utilizing two separately calculated equivalent levelized annual transformer losses (PQD^2 and PQE^2), as per the discussion in Section 1.5.2.2 (1-15).

2.9 Application Example

To fulfil the purpose of this chapter, the proposed power transformer loss evaluation method is assessed on a small scale real system, i.e. a vertically integrated energy system where the generation and transmission categories are under the auspices of a single entity that may be called a "Regulated Utility". More precisely, the system characteristics and the relevant financial data (concerning capital and operating expenditure) are obtained from the Cyprus Power System (CY.P.S.). This system constitutes an example where the transformers' user (Electricity Authority of Cyprus) possesses its own generation and transmission facilities. Thus, the proposed method (addressed in the previous sections of this chapter) is numerically evaluated in this section, offering a thorough real case application and benchmarking against the IEEE C.57.120-1991 [3] method.

2.9.1 Load and Energy Forecasts

As per the methodology defined in Sections 2.2 – 2.8, it is necessary to obtain forecasts of the system's peak demand and energy generation over the transformer life cycle (e.g. 30 years). The CY.P.S relevant forecasts are utilised [26] in this work. In particular, Figure 2-7 illustrates the CY.P.S's peak demand (*PForecasted* - *MW*) forecast on a 30 year horizon.

In addition, Figure 2-8 illustrates the forecasted energy requirements (*UG* - *MWh*) [26] from CY.P.S planned facilities obtained by Electricity Authority of Cyprus at the end of 2009. In particular these planned facilities (peaking generation additions) will mainly include CCGT's.

It is worth noting that these generation additions would use Diesel LSFO until 2015. At 2016 it is expected to switch to Liquid Natural Gas (*LNG*). This scenario has been incorporated in our analysis, as illustrated by Figure 2-9 which illustrates the calculated fuel consumption (*FuC* - *MT*) by the planned peak generation units.

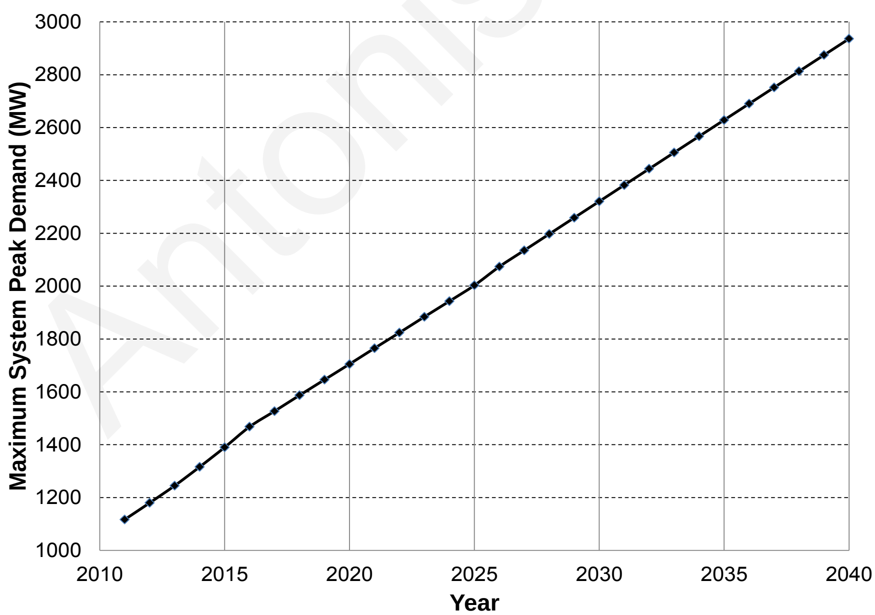


Figure 2-7: Forecasted Maximum System Peak Demand ($P_{Forecasted}$ – *MW*) [26]

The calculated fuel consumption (*FuC*) is the converted *MW*h energy (*UG*) illustrated by Figure 2-8, by following the methodology detailed in (2-2). This conversion assumes Net Calorific Values (*NCV*) of 41 *MJ/MT* and *49 MJ/MT* for Diesel LSFO and LNG fuels respectively. It further assumes 27% efficiency (n_{ef}) for the machines burning diesel LSFO and 50% efficiency for the machines that will burn LNG [27], [28].

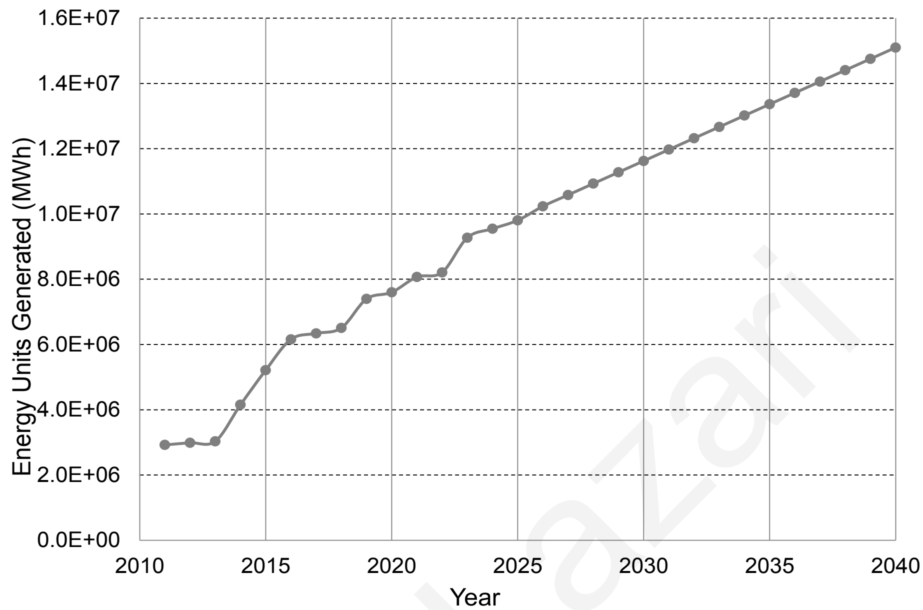


Figure 2-8: Forecasted Energy Generation by Peaking Gen. Units (*UG – MWh*) [26]

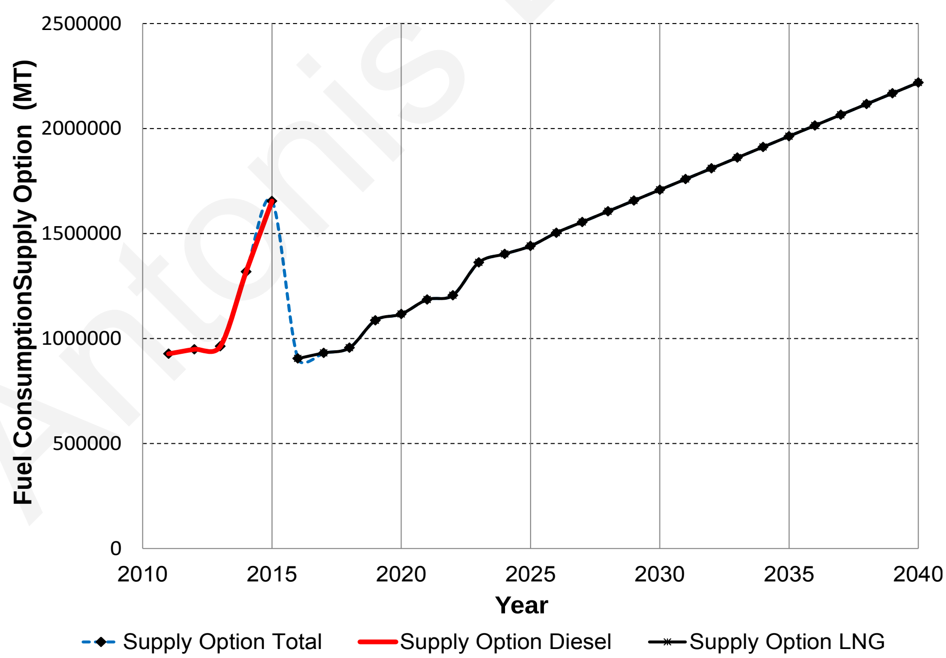


Figure 2-9: Forecasted Fuel Consumption from "Peaking Gen. Additions" (*FuC – MT*)

2.9.2 Forecasted Energy Prices

Predictions of any fuel dependent energy prices over the life-cycle of a power transformer should be carried out in loss evaluation endeavours. The methodology found in the IEEE

C57.120-1991 [3], models the changes in the underlying variable by a constant trend every year (2-26).

$$F_v = P(1+i)^N \tag{2-26}$$

Where P is the present value of energy (fuel component), F_v is the future value of energy (fuel component), N is a future year and i is a given escalation rate.

In contrast to the standardized approach [3], the current work has adopted the forecasting procedure and results of the method proposed in [29] in order to address the impact of escalated fuel prices in life-cycle loss evaluations of power transformers. In [29], a widely used approach in economics (Markov-regime switching models) [30] is utilized, which allows escalation rates to switch between a mixture of constant rates, where the weight attributed to each constant term is purely determined by relevant historical data. The application of the method pertains to the calculation of projected fuel prices as per the specific fuel used (or would be used) in the generation mix of the system under study.

As already been stated in Section 2.9.1, the generation mix scenario for CY.P.S includes the use of Diesel (LSFO) until 2015, and switch to Liquid Natural Gas (*LNG*) in 2016. Thus, Figure 2-10 [29] illustrates the calculated prices (*$/GJ*) for Diesel (LSFO) and LNG for the 30th, 40th and 50th percentiles for a 360 month forward horizon. The resulting fuel prices are then correlated to the system's generation mix and predicted energy needs so as to estimate the annual fuel cost during the transformer's useful life. The manipulation of these cost predictions (Figure 2-10) will be in more detail explained during the process of the current example.

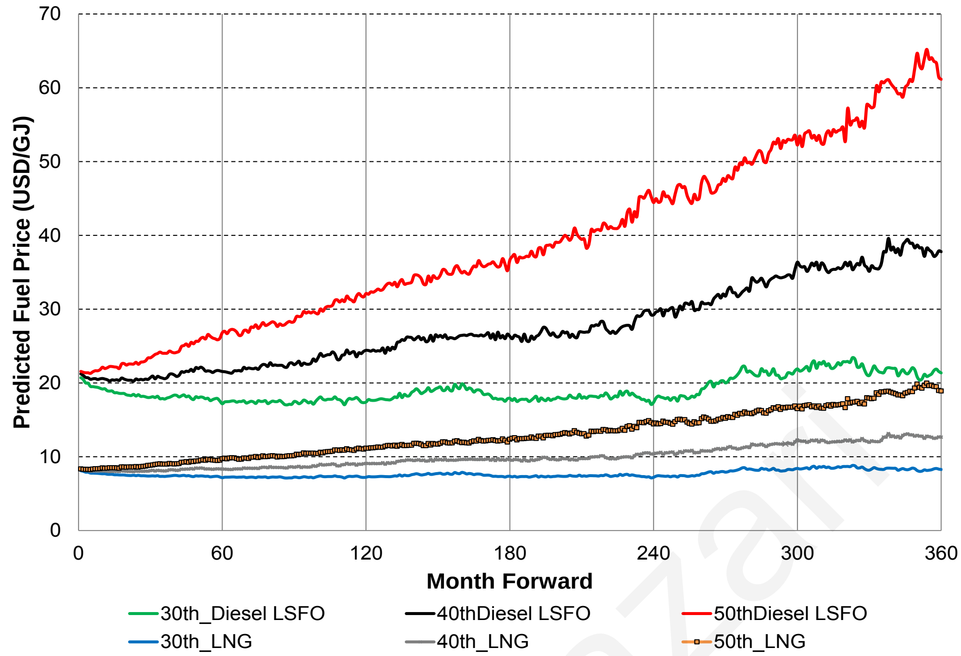


Figure 2-10: 30th, 40th and 50th Percentiles of Nominal Forecasted Diesel LSFO (FFP_{Diesel}) and LNG Prices (FFP_{LNG})

2.9.3 Weighted Multiplying Factors

2.9.3.1 Allocation of Weighted Multiplying Factors to Operating Costs

The methodology detailed in Section 2.5 is adopted to weight an operating expenditure to its corresponding demand and energy component of the cost of losses (2-5). Therefore the "weighted multiplying factors" associated with operation costs and repair and maintenance costs are reflected in Table 2.3. For CY.P.S, $\varepsilon \times \tau = 0.38$ for operation costs and $\varepsilon \times \tau = 0.876$ (2-5) for repairs and maintenance costs, as per the Load Factors (*LF*) tabulated in Table 2.3.

Table 2.3
Allocation of Weighted Multiplying Factors

Cost Item	Demand Component (%)	
Operation	$cc_{op} = \frac{1}{1+0.38 \times LF}$	84 % *(LF: 0.518)*
Repairs & Maintenance	$cc_{rm} = \frac{1}{1+0.876 \times LF}$	69 % *(LF: 0.518)*
	Energy Component (%)	
Operation	$ec_{op} = 1 - cc_{op}$	16% *(LF: 0.518)*
Repairs & Maintenance	$ec_{rm} = 1 - cc_{rm}$	31% *(LF: 0.518)*

2.9.3.2 Allocation of Weighted Multiplying Factors to Fuel Costs

Following the procedure in Section 2.5.2, the allocation of weighted factors to fuel costs that follows pertains to generating units consuming diesel LSFO [26]. Both recorded and estimated data are tabulated in Table 2.4, which are related to a) to “sent out” energy units (*E - MWh*) from a generating plant and their corresponding fuel consumption (*MT*) (2-6), and b) to the sum of machines’ running hours to provide the zero load losses (*F – hours*) and their corresponding fuel consumption (*MT*) (2-6).

Table 2.4
Fuel and Energy Data CY.P.S [26]

Year	**Sent Out Energy Units (*MWh*)**	**Fuel Consumption for Sent Out Units (*MT*)**	**Sum of Machines Running Hours for Zero Load Losses (*Hours*)**	**Zero Load Fuel Consumption (*MT*)**
2002	3535	1194	32.9	29.3
2003	13848	4485	129.3	114.8
2004	23371	7800	218.2	193.7
2005	38846	14846	393.8	349.6
2006	17495	6577	250.2	222.2
2007	40648	13532	286.4	254.3
2008	26972	10401	214.3	190.3
2009	29647	11178	214.9	190.8
2010	9334	3481	87.1	77.4
	E: 22633		*F: 203*	

Figure 2-11 illustrates the plotted recorded data for “Sent Out Energy” (*E - MWh*) and the corresponding fuel (diesel LSFO) consumption (*MT*) for each year as per Table 2.4. A straight line is fitted between the plotted points using the method of least squares. The slope of this line results in the incremental fuel rate for the generating plant’s machines burning diesel LSFO fuel (2-6). For this particular example the incremental fuel rate *INFR = 0.3624 MT/MWh*.

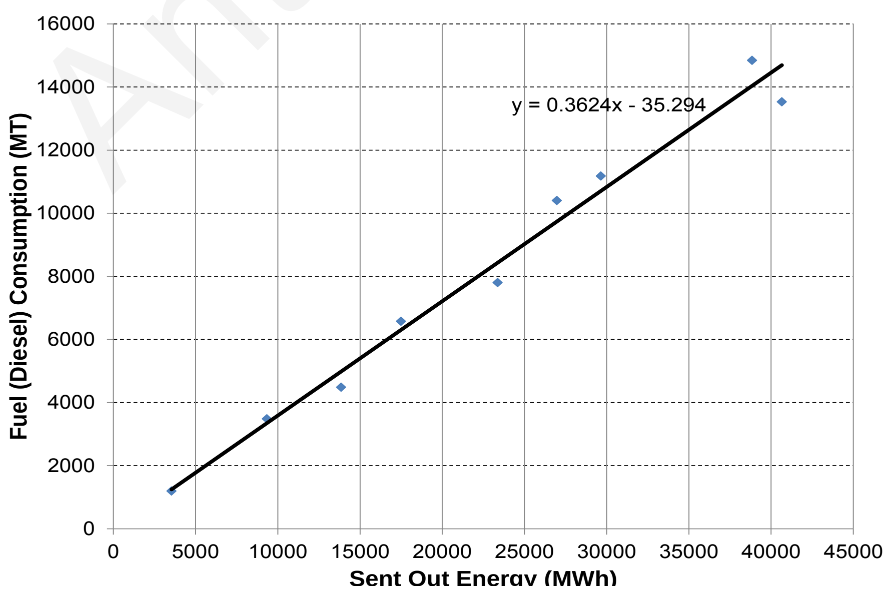


Figure 2-11: Incremental Fuel Rate Calculation for Machines Burning Diesel LSFO (2-6)

Furthermore, Figure 2-12 illustrates the plotted recorded data for the machines running hours to provide the zero load losses and the corresponding zero load fuel consumption (2-6). A straight line is fitted between the points and the slope of this line yields the zero load fuel rate (*ZRFL*). The *ZRFL* for the machines burning diesel LSFO fuel is calculated at *ZRFL = 0.8879 MT/hour*.

Referring to (2-7), the calculated *p.u* demand (cc_{fuel}) and energy (ec_{fuel}) component weight factors for the machines burning diesel LSFO are calculated as illustrated in (2-27).

$$cc_{LSFO} = \frac{F \times ZRFL}{E \times INFR + F \times ZRFL} =$$

$$\frac{203 \times 0.8879}{22633 \times 0.3624 + 203 \times 0.8879} = 0.02165 \qquad (2\text{-}27)$$

$$ec_{LSFO} = 1 - cc_{LSFO} = 0.978.$$

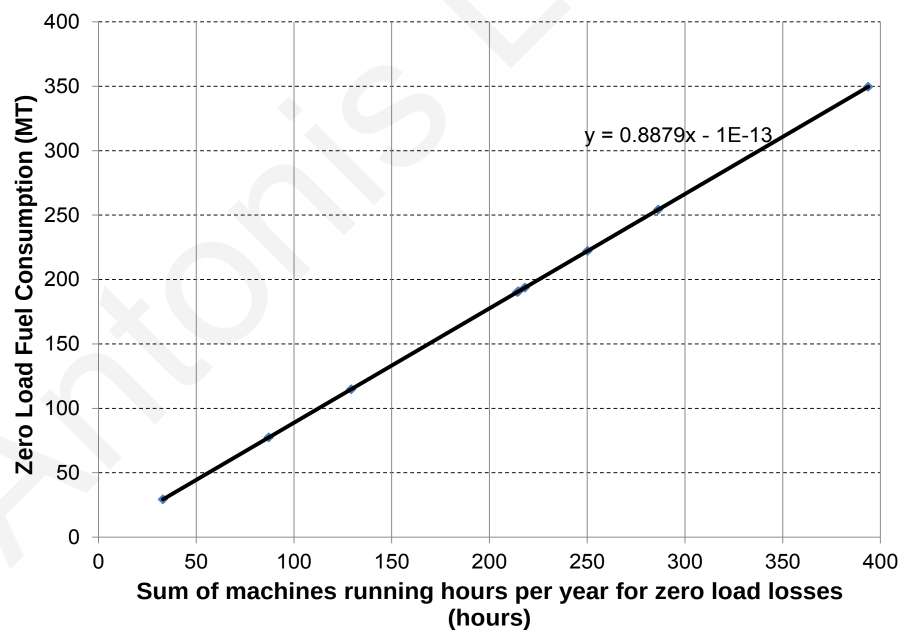


Figure 2-12: Zero Load Fuel Consumption for Machines Burning Diesel LSFO (2-6)

2.9.4 Demand Component of the Cost of Losses

2.9.4.1 Demand Component Attributed to Operating Costs

Table 2.5 tabulates the financial parameters necessary to determine demand component of the cost of losses attributed to the repair and maintenance (D_{gop_RM} - *\$/kW*) costs that are classified under the generation category of the *CY.P.S*. Using these data, the de-inflated costs are plotted against the system's maximum demand (*P - MW*) of each corresponding year as illustrated in Figure 2-13.

Table 2.5
Repairs & Maintenance Costs (Generation), Inflation Rate, System Peak Demand

Year	*Cost of Repairs and Maintenance ($) - Generation*	*Inflation Rate Per Annum (%)*	*System Peak Demand (MW)*
2005	5,305,000	2.60	855
2006	4,579,000	2.50	903
2007	3,926,000	2.40	1035
2008	4,696,000	4.70	1003
2009	10,044,000	0.30	1098
2010	7,602,000	-	1118

Once the incremental cost value is determined i.e. the slope of the graph (a_{g_RM} - *$/MW*), the annual demand component of the cost of losses attributed to the repairs and maintenance costs (D_{gop_RM}) for generation category is evaluated as per (2-28).

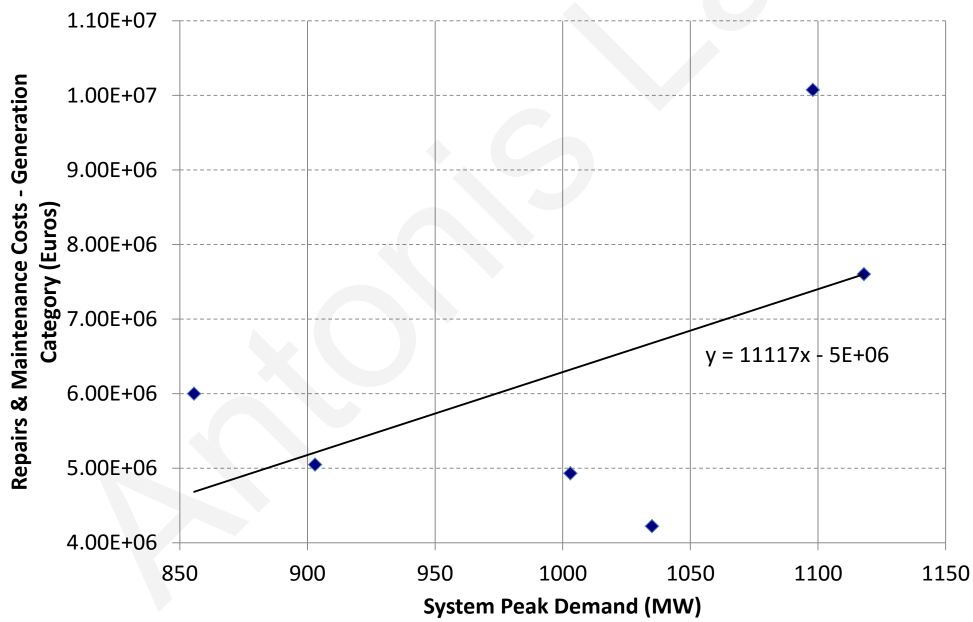


Figure 2-13: Incremental Cost ($/MW) – Repairs & Maintenance (Generation)

$$D_{g_{OP\_RM}} = SFcc_g \times cc_{rm} \times a_{g\_RM}$$
$$D_{g_{OP\_RM}} = (\frac{2}{3} \times 1.1) \times 0.6933 \times 11.117 = 5.652\$/kW \quad (2\text{-}28)$$

Where cc_{rm} is the percent weighted multiplying factor for the demand component of the cost of losses assigned for repairs and maintenance costs (Table 2.3). $SFcc_g$ is the size factor for generation's category related costs, assuming a Reserve Margin (*RM*) of 10% (0.1 p.u).

2.9.4.2 Demand Component Attributed to Fuel Costs

In this evaluation the 40th percentile prediction (Figure 2-10) has been considered as the benchmark scenario for the corresponding prices of diesel LSFO and LNG fuels. These are the two fuels that will be used in the generation mix of the CY.P.S in a 30 year horizon [26]. Consequently, Figure 2-14 illustrates the application of the methodology to obtain a future cost trend attributed to fuel usage and prices with respect to the forecasted generation demand. The y-axis cost (*FC -$*) (2-3) is determined by multiplying the total predicted fuel consumption (*FuC - $/MT*) (Figure 2-9) with the 40th percentile scenario of the forecasted fuel prices (FFP_{LSFO}, FFP_{LNG} - *$/MT*) as per Figure 2-10 and the demand component factor for fuels cc_{fuel}. Following the definition in (2-12), the annual demand component (D_{gfuel}) for the cost of fuels is the weighted average (2-29) of the two slopes illustrated by Figure 2-14.

$$D_{g_{fuel}} = \frac{cc_{LSFO} \times n_1 \times \alpha_1 + cc_{LNG} \times n_2 \times \alpha_2}{n_1 + n_2} = \frac{0.02165 \times 5 \times 1187.74 + 0.02165 \times 25 \times 555.55}{25+5} = 17.292\$/\text{kW} \tag{2-29}$$

Where n_1 is the number of years that diesel LSFO will be in use and n_2 is the number of years that LNG will be in use. For this example a weight factor (cc_{LSFO}= cc_{LNG}) of 2.16 % as per (2-27) has been used. Consequently by evaluating (2-29) the demand component of the cost of losses attributed to fuels (D_{gfuel}) is calculated at 17.292 $/kW.

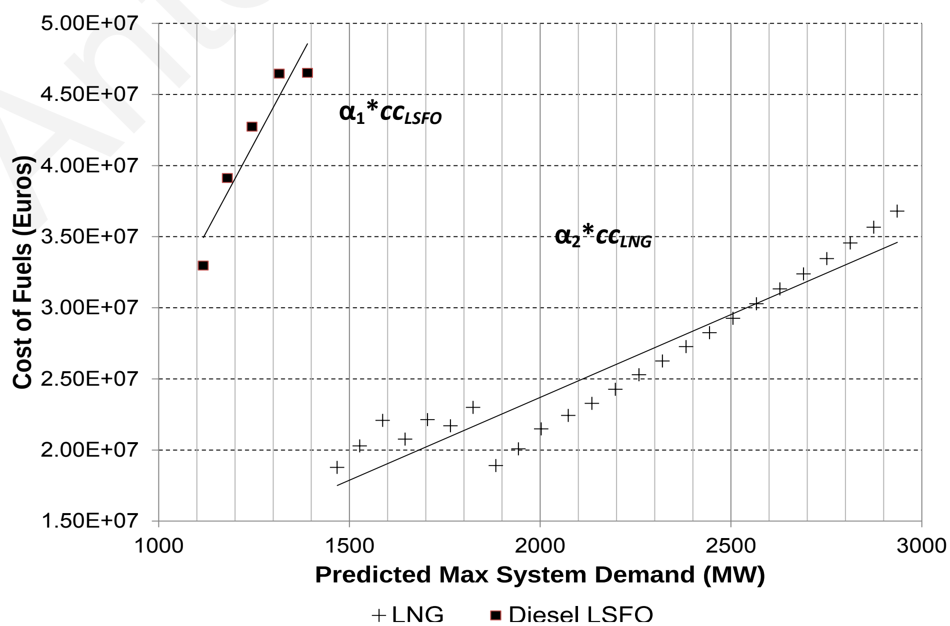


Figure 2-14: Demand Component of CY.P.S Fuel Cost

2.9.4.3 Aggregate Demand Component of Losses

With reference to formulation in (2-15) the annuitized cost per kW of new peaking generation units (*ACPG - $/kW*) is evaluated by assuming a real discount rate (*d)* of 10%, annuitized over 30 years, a reserve margin of 10% and C_{PG} of 900 $/kW. Similarly, with reference to (2-16), the annuitized cost per kW of planned transmission system installations (*ACTS - $/kW*) is found by assuming a real discount rate of (*d)* 10%, annuitized over 30 years and C_{TS} of 164.21 $/kW. Consequently, Table 2.6 tabulates the calculated demand component of losses (*D - $/kW*) attributed to the capital and operating costs, as per the two categories considered. It is noted that all calculated values are based on the proposed methodology by taking into consideration the appropriate category, size and weighted allocation factors.

Table 2.6
Aggregate Demand Component of Losses – CY.P.S

Annuitized Demand Costs per kW ($/kW)	D_{g_item} **($/kW)**	D_{t_item} **($/kW)**
ACPG (New Peak Generation Installation)	73.294	N/A
ACTS(Transmission System Installations)	N/A	11.88
Fuel (D_F)	17.292	N/A
Operation	0.0001	31.029
Repairs and Maintenance	5.6520	1.159
Green House Emissions	0.01866	N/A
Sum	D_{g_peak}: 96.248	D_{t_peak}: 44.068
$D_{peak} = D_{g\_peak} + D_{t\_peak}$	***140.316 $/kW***	

2.9.5 Energy Component of the Cost of Losses

2.9.5.1 Energy Component Attributed to Operating Costs

Table 2.7 presents the historical costs for operation as well as the inflation and the energy needs during the same period of the *CY.P.S.*

Table 2.7
Operation Costs (Transmission), Inflation Rate and Generated Energy (*MWh*)

Year	***Operation Costs ($) - Transmission***	***Inflation Rate Per Annum (%)***	***Units Generated (MWh)***
2005	3,952,000	2.60	4472585
2006	6,935,000	2.50	4735864
2007	9,575,000	2.40	5037688
2008	16,176,000	4.70	5322452
2009	19,161,000	0.30	5565134
2010	25,029,080	-	5950450

The ratio (\$/MWh) of the de-inflated costs to the total energy generated per year is plotted against each corresponding year as illustrated by Figure 2-15.

A straight line is then fitted on the plotted points using the method of least squares following the methodology described in Section 2.7.1. Consequently, the energy component of operation costs (E_{top_OP} - *\$/MWh*) allocated under transmission category is evaluated by (2-30).

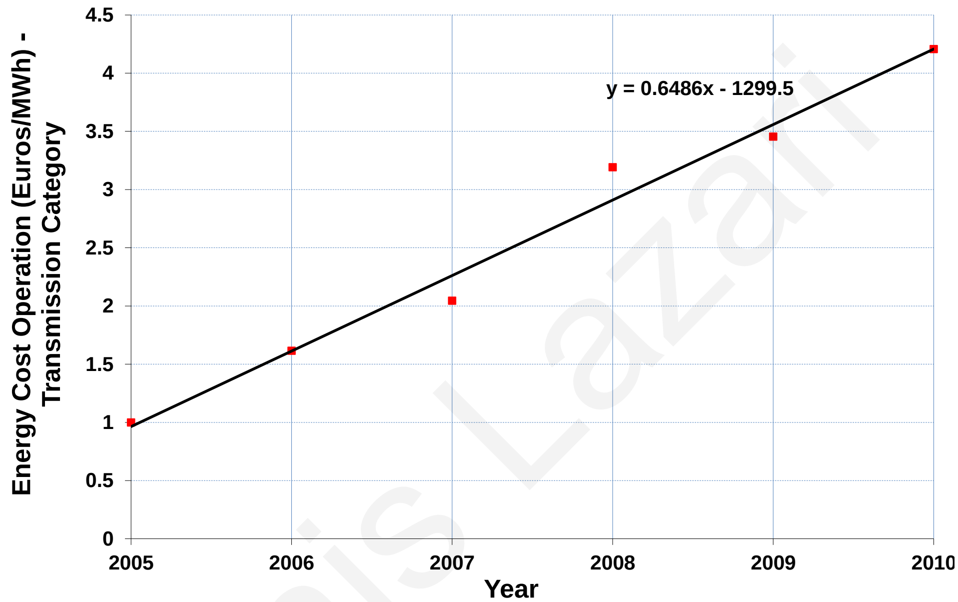


Figure 2-15: Incremental Cost (\$/MWh) – Operation Costs (Transmission)

$$E_{t_{op}\_op} = \left(\lambda_{t\_op} \times Y(Latest\_Year) + \delta_{t\_op}\right) \times ec_{op}$$

$$= (0.6486 \times 2010 - 1299.5) \times 0.16 = 0.67\$/\text{MWh} \tag{2-30}$$

Where ec_{op} is the percent weighted multiplying factor for the energy component of the cost of losses assigned for operation costs (Table 2.3).

2.9.5.2 Energy Component Attributed to Fuel Costs

This part of the example case also incorporates the 40th percentile prediction for diesel LSFO and LNG pricing (FFP_{LSFO}, FFP_{LNG}) as per Figure 2-10. It further uses an energy component weight factor for fuels (ec_{LSFO}= ec_{LNG}) of 97.8% for planned generation [26] and a real discount rate (d) of 10%. Figure 2-16 illustrates the application of the methodology on the energy cost (fuel component) of planned generation where LNG is expected to replace diesel LSFO fuel in 2016, as illustrated by Figures 2-8 and 2-9. Using (2-21) as a reference, the annuitized energy component of losses attributed to forecasted fuel prices (E_{gfuel} - *\$/MWh*) is calculated at *102.35 \$/MWh* by through (2-31).

$$E_{g_{fuel}} = \left[\sum_{j=1}^{4} \frac{ec_{LSFO} \times FC_j}{UG_{Diesel\,j}} \times pw_j + \sum_{j=5}^{30} \frac{ec_{LNGe} \times FC_j}{UG_{LNG\,j}} \times pw_j \right] \times crf_n \tag{2-31}$$

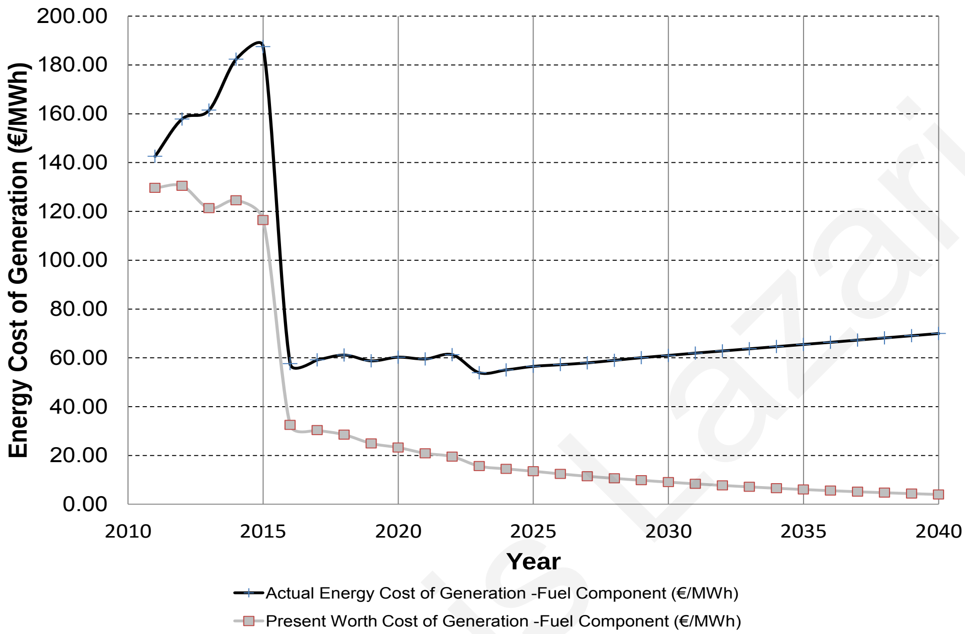


Figure 2-16: Annuitized Energy Component of CY.P.S Fuel Costs

2.9.5.3 Aggregate Energy Component of Losses

Table 2.8 tabulates the calculated annuitized energy component of losses attributed to all relevant operating costs classified under generation and transmission categories as per the specific system's accounts. It is noted that all calculated values are based on the proposed methodology by taking into consideration the appropriate category, size and weighted allocation factors. The Green House Emissions costs allocated to the energy component (Table 2.8) follow the same calculation principles (weighted multiplying factors, size factors etc) described for the fuel costs.

Table 2.8
Aggregate Energy Component of Losses – CY.P.S

Annuitized Energy Costs per MWh *($/MWh)*	$E_{g\_item\_n}$ ***($/MWh)***	$E_{t\_item\_n}$ ***($/MWh)***
AE_F	102.35	N/A
Operation	1.065	0.670
Repairs and Maintenance	0.420	0.087
Green House Emissions	0.914	N/A
Sum	E_{g_peak}: 104.749	E_{t_peak}: 0.757
$E_{peak} = E_{g\_peak} + E_{t\_peak}$	***105.51 $/MWh***	

2.9.6 Total Ownership Cost of Power Transformers in CY.P.S

A numerical example is provided in this section for total ownership cost (*TOC - $)* by evaluating (1-2) in Chapter 1. Table 2.9 tabulates the numerical factors which are utilised to evaluate the proposed *TVL* (2-25) of power transformers. The evaluation assumes that $D_{PEAK}=D_{BASE}$ and $E_{PEAK}=E_{BASE}$ i.e. base and peak costs are used as if they were the same.

Table 2.9
Operational and Financial Specifics – CY.P.S

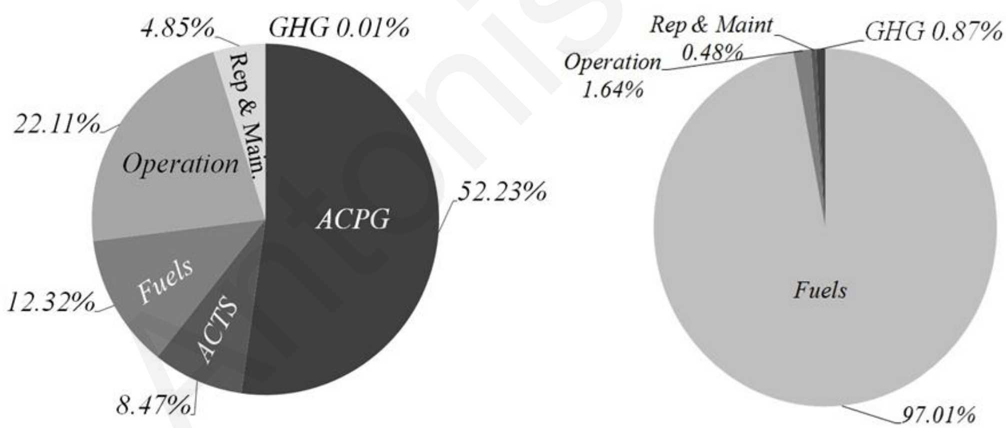
Load Factor (*LF – p.u*) (Transmission System 2010)	0.518
Calculated Loss Load Factor Equation (CY.P.S)	$LLF = 0.1 \cdot LF + 0.9LF^2$
Loss Load Factor (*LLF – p.u*) (2010)	0.293
Peak responsibility factor for Step Down Substation Transformer (*PRFS – p.u*)	0.81
Availability Factor (*AF – p.u*)	0.95
Cooling operation per year (*FOW – p.u*)	0.30
Real Discount Rate (*%*)	10
Future Inflation Rate (*%*)	2
Levelized Annual Peak Load of Transformer as per its life-cycle, for Demand Component (*PQD – p.u*)	0.4081
Levelized Annual Peak Load of Transformer as per its life-cycle, for Energy Component (*PQE – p.u*)	0.4564
D_{PEAK} (*$/kW*)	140.316
E_{PEAK} (*$/MWh*)	105.51

The evaluated *TOC* equation as per the CY.P.S specifics, tabulated in Table 2.9, is provided by (2-32). The process illustrated in (2-32) summarizes the definitions in (2-2), (1-2) and their proposed modification (through the process in Chapter 2) illustrated in (2-25).

Where *NLL* are the no-load losses, *LL* accounts for the load losses and *AUX* are the auxiliary losses of the transformer. It is noted that the loss evaluation factors of (2-32) should be updated on a case by case basis. This is achieved by appropriately updating the data tabulated in Table 2.9.

The dominant elements in the process of evaluating the loss factors of (2-32) are the demand (D_{PEAK} – *\$/kW*) and the energy component (E_{PEAK} – *\$/kWh*) of losses. This is because these elements are heavily dependent on the relevant capital and operating expenditures of the utility which may vary substantially. Figure 2-17 shows the subdivision of all costs for the two components, as per the results tabulated in Tables 2.6 and 2.8 respectively.

$$
\begin{gathered}
TOC = PP + TVL \\
TVL = CostNLL + CostLL + CostAUX \\
CostNLL = N \times f_1(D,E) \times NLL \\
CostLL = N \times f_2(D,E) \times LL \\
CostAUX = N \times f_3(D,E) \times AUX \\
\Rightarrow f_1(D,E) = 1018.46\$/kW \\
\Rightarrow f_2(D,E) = 71.75\$/kW \\
\Rightarrow f_3(D,E) = 417.62\$/kW
\end{gathered}
\qquad (2\text{-}32)
$$



a. Demand Component (D_{PEAK}) ***b.* Energy Component (E_{PEAK})**

Figure 2-17: Percent Subdivision of Demand and Energy Components Costs CY.P.S

2.9.7 Sensitivity Analysis of Proposed TVL formulation

It is well understood that some form of uncertainty exists with future energy related price forecasts; uncertainty that increases with longer time horizons. The latter reflected the need to generate and assess a number of cost evaluation scenarios utilising different fuel pricing forecasting scenarios. Table 2.10 tabulates the sensitivity analysis of incorporating the 30th, 40th (benchmark scenario) and 50th percentile of fuel predictions (Figure 2-10), on the demand

and energy components calculations for cost of loss. It specifically shows that when comparing the % difference of D_{peak} and E_{peak} components by assessing the 40th percentile and the 30th percentile predictions, the % difference is more evident in E_{peak} (-17.16%). This indicates that energy component E_{peak} calculation is more dependent on future forecasting prices rather than demand component D_{peak} (-10.91 %) and therefore should be interpreted with care.

Table 2.10
Sensitivity Analysis for Different Fuel Price Predictions

Fuel Price Percentile Prediction	**30th**	**40th**	**50th**
D_{peak} (*€/kW*)	124.987	140.316	151.597
E_{peak} (*€/kWh*)	0.0874	0.1055	0.1265
Deviation from benchmark scenario (D_{peak})	-10.91 %	-	8.05%
Deviation from benchmark scenario (E_{peak})	-17.16 %	-	19.90 %

In addition to these, Table 2.11 tabulates the influence of other factors in evaluating the loss factors of (2-32). For example if the *PRFS* factor changes from 0.5 to 1 p.u. then the *LL* loss factor ($f_2(D,E)$-*\$/kW*) would increase by +21.96 % while the *NLL* ($f_1(D,E)$-*\$/kW*) and *AUX* ($f_3(D,E)$-*\$/kW*) loss factors would remain unchanged.

Table 2.11
Sensitivity Analysis for Loss Factors

	Assumed Variation	**NLL Loss Factor % Change ($f_1(D,E)$-\$/kW)**	**LL Loss Factor % Change ($f_2(D,E)$-\$/kW)**	**AUX Loss Factor % Change ($f_3(D,E)$-\$/kW)**
LLF	0.3 →0.7	-	51.00 %	-
PRFS	0.5 →1.0	-	21.96 %	-
AF	0.5 →0.95	43.40 %	-	-
FOW	0.2 →0.6	-	-	53.20 %
PQD	0.4 →0.9	-	46.7 %	-
PQE	0.4 →0.9	-	70.22 %	-

On a final note [31] tabulates a comparison of loss evaluation figures of several countries. The two key elements acknowledged in [31] that impact on the variation of the published loss figures are: a) different economic conditions and b) credibility/method of calculation. It should be therefore kept in mind that because the loss factors are of eminent influence in the design/manufacturing and purchasing processes, these should be calculated accordingly and the method of calculation should be disclosed. Transparency in these endeavours could lead to win-win scenarios both for utilities and manufacturers.

2.9.8 Benchmarking of the Proposed Method

To facilitate a valid comparison to the IEEE standard method [3], the calculated D_{peak} is benchmarked against the "Levelized Total System Investment Cost" (*LIC*). To evaluate the *LIC* value as per [3], a Fixed Charge Rate for Generation level (*FCRG*) of 12% and a Fixed Charge Rate for Transmission level (*FCRS*) [3] of 14% have been assumed, as shown in Table 2.12. The difference between the two is because D_{peak} includes the fixed portion of the system's operating expenditure.

Table 2.12
Benchmarking of Fixed Component of Losses

Evaluation of IEEE C57.120-1991 Method on CY.P.S Characteristics	**Evaluation of Proposed Method on CY.P.S Characteristics**
$^{*}LIC = GIC \times FCRG + SIC \times FCRS$ $LIC = 900 \times 0.12 + 164.21 \times 0.14 = 130.99$ $/kW * The acronyms used are as defined in (1-12)	D_{peak}= 140.316 $/kW ** ** As calculated in Table 2.6

Furthermore the calculated E_{peak} is benchmarked against the "Levelized Energy Cost for Load Loss Evaluations" (*LECL*) [3]. Table 2.13 tabulates the corresponding comparison.

Table 2.13
Benchmarking of Variable Component of Losses

Evaluation of IEEE C57.120-1991 Method on CY.P.S Characteristics	**Evaluation of Proposed Method on CY.P.S System Characteristics**
$LECL = SPWECY \times crf_n$ * $LECL = 1029.819 \times 0.106 = 109.24$ $/MWh *The acronyms used are as defined in (1-12)	E_{peak}= 105.51 $/MWh ** ** As calculated in Table 2.8

The discrepancy is attributed to the fact that [3] proposes the use of constant escalation rates (on a yearly basis) to determine the future energy values over the life cycle of a transformer. The theoretical background of these escalation rates is not defined in the standard's methodology. For evaluating *LECL* as per the IEEE C57.120-1991 method, a constant escalation energy rate of 3% has been assumed until 2016 and a constant escalation energy rate of 1% has been assumed for the 2016-2040 period. The two different escalation rates reflect on the planned fuel usage by CY.P.S (Diesel up to 2016 and LNG from 2016-2040).

However, the proposed approach offers a globalized statistically-based tool, for estimating future energy rates (by using the derived fuel price forecasts). The statistically based escalation rates are specifically derived for each fuel used (or would be used) in the generation mix of the system under study.

2.9.9 Current CY.P.S Demand and Energy Costs

It should be noted that the example procedure (Section 2.9.1 - 2.9.6) and the resulting transformer loss figures were carried out on behalf of the local electricity authority (E.A.C) in their effort to update the system's specific loss figures used in transformers' tender evaluations using validated operational and financial specifics. To this end, the numerical evaluation presented in the previous sections relates to the work carried out in 2011.

However, the proposed method was developed in the form of a software tool, which is able to carry and process a large volume of updated data. Thus, the user (i.e. E.A.C) has the ability to update the database of the model with more recent historical data (operational and financial), as well as updated predicted values (fuel cost, peak load, energy demand etc) to re-estimate and recalculate the utility's loss figures on a yearly or any other longer period basis. It is our belief that because the loss factors are of eminent influence in the design/manufacturing and purchasing processes, these should be re-calculated and updated quite frequently. The proposed method and corresponding model are designed to satisfy this need.

To this end, Table 2.14 tabulates the updated Demand (D_{peak}) and Energy (E_{peak}) components of losses for the CY.P.S, as calculated in 2015. For the calculation of these figures, the model has incorporated the up-to-date realistic financial data and system characteristics as provided by the local Electricity Authority. These include the updated database of the historical data (including the historical system specifics - fuel cost, peak load, energy demand, system expenditure etc - from 2011-2014). The calculations, also, incorporate the predicted fuel cost, peak load and energy demand reference to [26]. It is worth noting that the updated Demand and Energy components of losses were calculated following the E.A.C's expectations that the generation mix would be mainly based on Diesel LSFO until 2016, and that this type of fuel would be replaced by Liquid Natural Gas (*LNG*) in 2017. In addition to these, the updated demand components of losses were calculated using the 30th percentile prediction (Figure 2-10) for the corresponding prices of diesel LSFO and LNG fuels, since this is the percentile range that fits the trend of the worldwide low current fuel prices.

Thus, Table 2.14 shows that the current demand and energy components of losses are decreased with respect to 2011 equivalent values. Table 2.14 also tabulates the percentage difference between the calculated *Demand* and *Energy* components of losses for the CY.P.S in 2011 and in 2015. It is, thus, pointed out that the major percentage difference is observed on the energy component (*E*) of losses

Table 2.14
Updated Demand and Energy Components (2015)

	2011	***2015***	***% Difference***
D_{peak} **($/kW)**	140.316	124.69	-11.06
E_{peak} **($/MWh)**	105.51	55.29	-47.59

This is because the fuel cost influence, which affects both the demand and energy components of losses during the complete cycle of a transformer's 30 year horizon, is dominant. The *Demand* and *Energy* calculation carried in 2011 has adopted LSFO costs (40^{th} percentile) for a 6 year horizon. The *Demand* and *Energy* calculation carried in 2015 has adopted LSFO costs (30^{th} percentile – since the worldwide oil prices are experiencing a diminishing trend at present) for a two year horizon. With reference to Tables 2.6 and 2.8, the effect of system expenditure on the updated values of *Demand* and *Energy* is relatively low and the percentage difference relies in the range of 1-2% for all system expenditures found in these tables, except the fuel cost which was explained above. Nonetheless, it should be noted that the system and other expenditure of E.A.C over the past 5 years (2011-2015), has been inevitably decreased due to severe budget cuts pertaining to the financial crisis the country is facing.

3

Life-Cycle Loss Evaluation of Power Transformers Serving Large Photovoltaic Plants in Vertically-Integrated and Decentralized Systems

3.1 Introduction

3.1.1 General Remarks

In the light of disintegrated electricity markets and renewable energy penetration, the standardized methods (described in Section 1.5) for evaluating transformers' life cycle losses may not be suitable. Thus, the main objective of this Chapter is to propose a loss evaluation method that accommodates the particular needs and characteristics of power transformers serving large-scale PV applications. The fact that these transformers are obliged to serve an intermittent energy source calls for a suitable method to evaluate their life-cycle losses and total ownership costs. To this extend the demand and energy components of losses are properly unbundled, and in conjunction to PV plant's operational and financial specifics, a methodology integrating the implications of a transformer serving a PV plant is proposed. It should be noted that the loss evaluation method proposed in this Chapter is applicable to PV energy producers (Independent Power Producers (*IPP*) and Regulated Utilities (*RU*)) that supply power to the grid through a step-up power transformer.

3.1.2 Large-Scale PV Plant Characteristics

A large scale PV plant can either be part of a regulated utility or it can be owned by independent power producers/investors. The plant is comprised by a large number of PV modules connected in series. These modules are subsequently connected to a centralized inverter that performs a DC to AC conversion. In addition, a step-up power transformer is required to increase the inverter's output voltage to the transmission level voltage. For example a 4MW PV plant, supplying at transmission level, may occupy a field area that equals to 90000 m^2. It should be noted that the transformers serving large scale PV plants are permanently connected to the main grid, to ensure that the plant is supplied with energy when the PVs are not generating [32]. According to a study reported in [32] the transformers should remain permanent connected (energized) to:

a) Satisfy plants' auxiliary losses.

b) Track any sunshine and start the PV generation.

c) Help the system for reactive power compensation.

3.1.3 PV Generation Profile

Figure 3-1 illustrates a characteristic 24hour generation (*p.u*) profile of a PV plant as obtained by field measurements [33]. This profile is heavily dependent on the daily solar irradiation profile, on the PV panels' effective area as well as on the solar technology used [34]. As illustrated in Figure 3-1, the operation of a PV plant can be broadly classified in one of two different "states". The sun is down and there is no PV production (Non-Generating State - *NGS*). The sun is up and there is - a solar irradiation dependent - PV production (Generating State - *GS*).

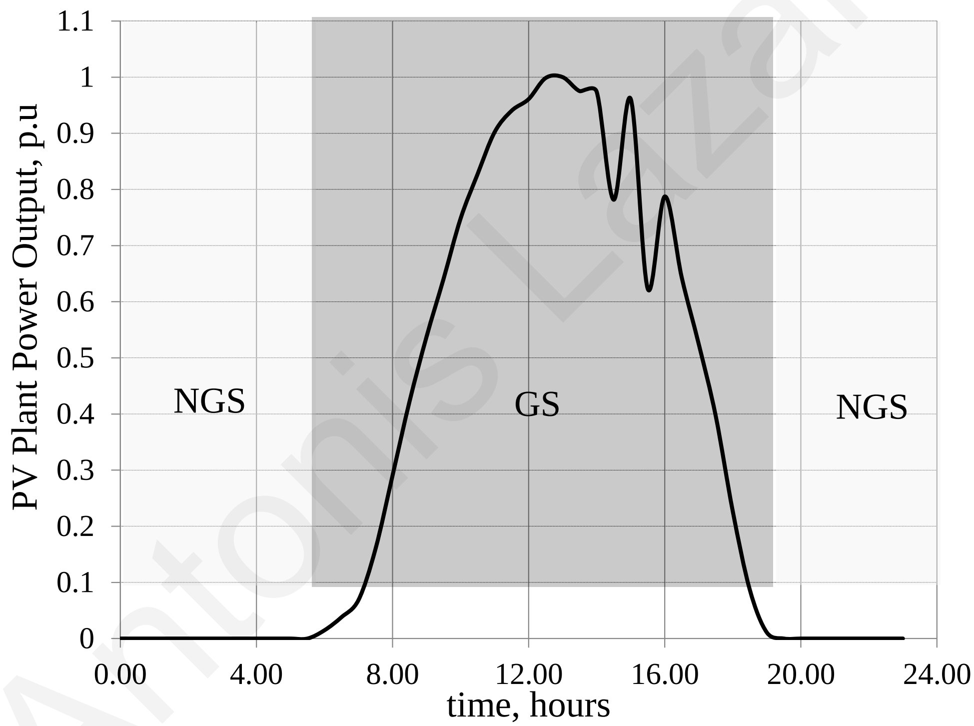


Figure 3-1: Operation States of PV Plant Power Output [33]

Moreover, Figure 3-2 illustrates the power-output duration curve of a PV unit over a year, as obtained by field data [33]. It specifically illustrates that the PV plant considered, is at its GS for approximately 4380 hours (i.e. 50%) in a year.

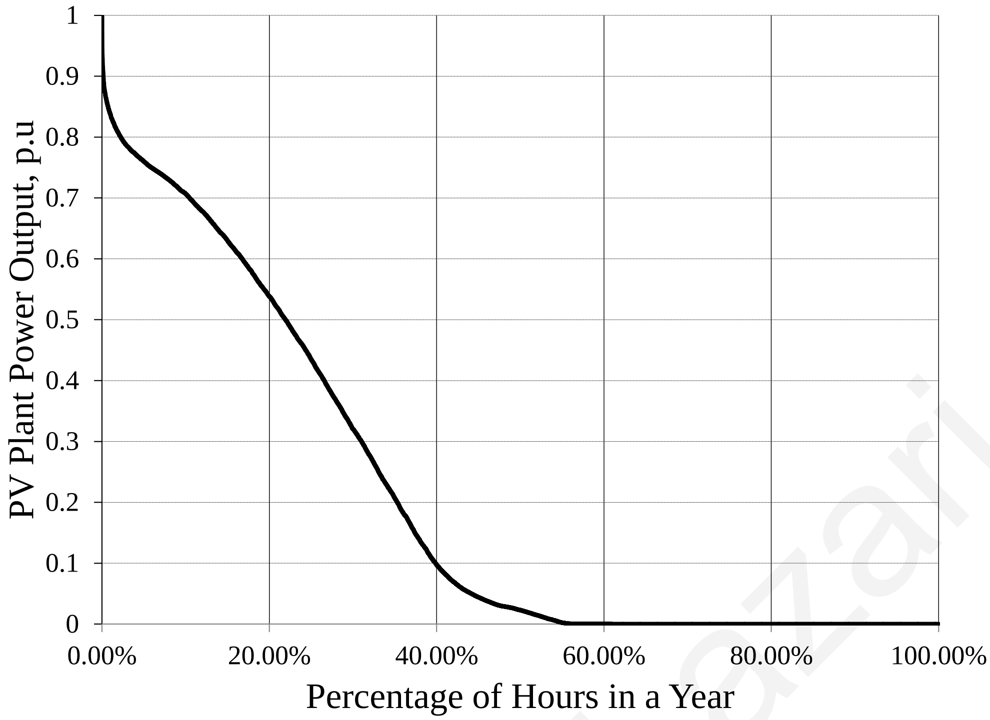


Figure 3-2: Load Duration Curve of a PV Plant [33]

3.2 Theoretical Discussion of Proposed Method

It is reiterated that the loss evaluation method proposed in this Chapter is applicable to PV energy producers (independent or part of a regulated utility) that supply power to the grid through a step-up power transformer. The key element in capitalising the losses in these step-up transformers is the proper definition of the demand and the energy components of the cost of losses. As earlier defined, the demand component (*D*) is the cost of capacity in *$/kW* to serve the power used by the losses. In addition to this, the energy component is the present value of the energy that will be used by one kilowatt of loss during the life-cycle of the plant under study in *$/kWh*. To this extent, it is important to appreciate exactly how these components should be evaluated, bearing in mind: a) who is the owner of the PV plant and transformer b) what are his/her enforced regulatory obligations and c) what are the operational and financial characteristics of each individual large-scale PV plant.

3.2.1 Loss Evaluation Method for PV Independent Power Producers (*IPP*)

3.2.1.1 Proposed TVL

Through the course of the day, a PV plant will most likely operate in one of two different states. When operated in its Generating State (*GS*), the PV plant is responsible to cover its own energy needs and losses, as well as to supply energy to the collector grid. When operated in the Non-Generating State (*NGS*), its auxiliary needs and losses should be covered from the main grid supply (i.e. buy energy from a supplying utility, when its generation potential is low).

Thus, Figure 3-3 illustrates the fundamental logic of the transformers' loss evaluation method applicable to Independent PV Power Producers. It is merely based on the two different PV plant operating states (*GS & NGS*) which concurrently define two loss evaluation elements. These are the "*PV Element*" and the "*System Element*". Under the "*PV Element",* the transformer owner should capitalise a significant part of his transformer losses, by considering the overall costs distributed over the lifetime of its PV Plant. This calculation should be based on a PV related Levelized Cost of Electricity (*LCOE - $/kWh*) calculation [36]. The *LCOE* is often cited as a suitable measure for the cost of electricity produced by different generating technologies. It represents the per-kilowatt-hour cost of building and operating a generating plant over its assumed financial life and duty cycle. The *LCOE* can account for a) the cost of capacity to serve the power used by the losses and b) the value of the energy that will be used by one kilowatt of loss during the life-cycle of the plant under study.

Furthermore, under the "*System Element*", the corresponding transformer losses should be capitalised by considering the electric rates payable to the supplying electric utility. In such a case the evaluation should be based on a levelized figure of the Commercial/ Industrial Electricity Rates (*CIER - $/kWh*) that are likely to be charged to the independent owner of the transformer, over the life-cycle of the PV plant. The *CIER*s may contain both a demand and an associated energy charge as per a time of use (*T.O.U*) tariff.

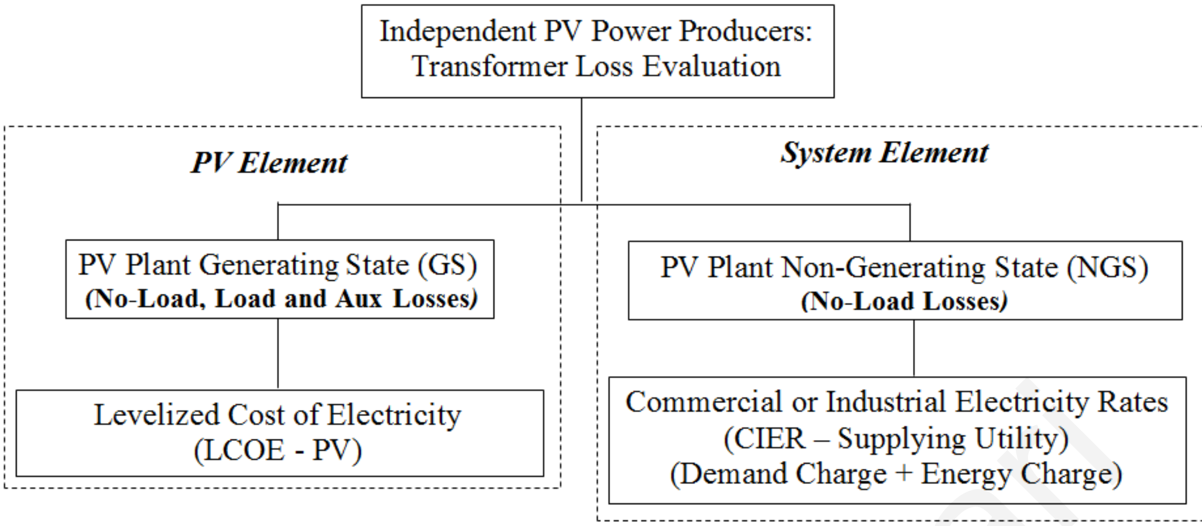


Figure 3-3: Loss Evaluation Method Applicable to Independent Power Producers (*IPP*)

Bearing in mind the principles described above, the total losses (i.e. no-load (*NLL - kW*), load (*LL - kW*) and auxiliary (*AUX - kW*) losses) of the step-up transformer, should be evaluated as per the two elements defined (see Figure 3-3). To this end, the *NLL* should be proportionally evaluated under both the PV and System elements respectively. The *LL* and the *AUX* may be evaluated under the PV element only. This is because the *LL* and *AUX* losses will be dominant during the generating state (*GS*) of the PV plant. This may be verified by assessing the ratio of the total exported energy during the generating state (*GS*) to the total imported energy during the non-generating state (*NGS*) of the PV plant. In contrast the *NLL* will occur whenever the transformer is energized (i.e. during both *GS* and *NGS*).

Hence, the two loss evaluation elements (PV & System) should be appropriately levelized to provide a total cost figure ($) as proposed in the formulation given in (3-1).

The process in (3-1) provides the Total Value of Losses for Independent Power PV Producers (TVL_{IPP}) and accounts for the sum of the present worth of each kilowatt of transformer loss (*NLL*, *LL* and *AUX*) over the life time of the PV Plant. Table 3.1 tabulates the further particulars of the nomenclature used in (3-1).

Three terms are present in (3-1), namely the no-load (*NLL*) which is the sum of the cost component that falls under the System Loss Evaluation Element and the cost component for the PV Loss Evaluation Element ($f_1(D,E)$ - *$/kW*), the load loss (*LL*) cost attributed to PV energy ($f_2(D,E)$ - *$/kW*)and the load loss auxiliary (*AUX*) cost component ($f_3(D,E)$ - *$/kW*). It is reiterated that part of the first term reflects ($f_1(D,E)$ - $/kW) on the System Loss Evaluation Element, while the remaining account for the PV Loss Evaluation Element (see Figure 3-3).

$$TVL_{IPP} = CostNLL + CostLL + CostAUX$$

$$\begin{aligned} CostNLL &= N \times f_1(D,E) \times NLL \\ CostLL &= N \times f_2(D,E) \times LL \\ CostAUX &= N \times f_3(D,E) \times AUX \end{aligned} \tag{3-1}$$

$$\Rightarrow f_1(D,E) = CIER_{UT} \times 8760 \times NGS_{FACTOR} \times AF + LCOE_{PV} \times 8760 \times GS_{FACTOR} \times AF$$
$$\Rightarrow f_2(D,E) = LCOE_{PV} \times PQE^2 \times LLF_{PV} \times 8760 \times GS_{FACTOR}$$
$$\Rightarrow f_3(D,E) = LCOE_{PV} \times FOW \times 8760 \times GS_{FACTOR}$$

Table 3.1
Nomenclature

$CIER_{UT}$ ($/kWh)	Levelized Commercial or Industrial Electricity Rates charged by Supplying Utility
$LCOE_{PV}$ ($/kWh)	Solar Photovoltaic Levelized Cost of Electricity
$NGS_{FACTORS}$ (p.u)	Proportion of Hours per year that the PV plant is operated in its Non-Generating State.
GS_{FACTOR} (p.u)	Proportion of Hours per year that the PV plant is operated in its Generating State.
PQE (p.u)	Levelized Annual Peak Load of Transformer as per its life-cycle
LLF_{PV} (p.u)	PV Plant Loss Load Factor
FOW (p.u)	Average hours per year the transformer cooling is operated
AF (p.u)	Availability Factor, the proportion of time in a year that a transformer is predicted to be energized

3.2.1.2 PV Loss Evaluation Element

As far as the PV Loss Evaluation Element is concerned, it is important to properly define the $LCOE_{PV}$, the *PQE* and the LLF_{PV} factors found in (3-1). The PV Plant's Levelized Cost of Electricity ($LCOE_{PV}$ - *$/kWh*) is the cost of generating PV electricity by considering the overall associated costs (capital & operating) distributed over the lifetime of the PV Plant as given in (3-2). Hence, it is applied to estimate the present value of the energy (*$/kWh*) that will be used by one kilowatt of loss during the life-cycle of the transformer.

$$LCOE_{PV} = \frac{IC + \sum_{j=1}^{N} OM_j \cdot pwf_j}{\sum_{j=1}^{N} Gpv_j \cdot pwf_j} \tag{3-2}$$

Within (3-2), *IC* is the initial PV capacity investment cost in \$, *N* is the life-cycle evaluation in years, pwf_j is the present worth factor of each equivalent year (*j*), Gpv_j is the calculated annual PV energy generation in *kWh* and OM_j is the operation and maintenance cost (*\$*) of each year considered in the evaluation.

The annual PV energy generation (Gpv_j), can be calculated as given in (3-3), by taking into consideration the annual predicted solar potential (sp_j – kWh/m^2) and the annual degradation rate (n_d) of the maximum rated output power of the PV panels [37]. The total effective area (A – m^2) occupied by the PV panels and the efficiency (n_{ef} - *%)* of the PV system are also considered.

$$Gpv_j = A \times sp_j \times n_{ef} \times (1 - n_d)^{j-1} \tag{3-3}$$

Furthermore, the levelized annual peak load of the transformer as per its life-cycle *(PQE)* is calculated based on the following two assumptions:

a) The transformer loading is coincident to the PV plant's power profile.

b) The PV plant's power profile is subject to the PV technology used, as it will be further discussed.

It is, thus, highlighted that the levelized annual peak load of the transformer (*PQE*) may concurrently account for the levelized annual transformer losses (PQE^2) as given in (3-4).

$$PQE^2 = [\sum_{j=1}^{N} P_j^{\,2} \cdot pwf_j] \cdot crf_N \tag{3-4}$$

P_j is the annual transformer peak load (*p.u*) that captures the changes in the PV modules' power performance. This performance can be initially improved and subsequently reduced depending on the PV technology used and its corresponding response to the "light soaking effect" [38]. Moreover, in both (3-2) and (3-4) a nominal discount rate (*d* - *%*) is utilised [21] to determine a) the present worth factor (pwf_j) for each year *j* considered and b) the capital recovery factor (crf_N) found in (3-4) - for the *N* years of the evaluation period.

A subsequent factor that needs to be properly defined is the loss load factor of the PV plant system (LLF_{PV} – *p.u*). It can be considered as the ratio of the PV plant's average power loss

($L_{average}$) to the PV plant's peak power loss (L_{peak}) over a given period of time (T) as in (3-5). In the absence of any measured loss values ($L(t)$) it may be assumed that the PV losses are proportional to the square of the PV plant's generation load (P_{PV} - MW) as shown in (3-5).

$$LLF = \frac{L_{average}}{L_{peak}} = \frac{\int_0^T L(t)dt}{L_{peak} \times T} \approx \frac{\int_0^T [P_{PV}(t)]^2 dt}{(P_{PV\,PEAK})^2 \times T} \qquad (3\text{-}5)$$
$$\rightarrow T = 8760 \times GS_{FACTOR}$$

3.2.1.3 System Loss Evaluation Element

As far as the System Loss evaluation element is concerned (Figure 3-2), it is important (for the PV plant owner) to estimate the *CIERs - \$/kWh* that are likely to be paid to the supplying utility over the life-cycle of the PV plant. That is for capitalising the associated portion of the *NLL* that falls under the Non-Generating State (*NGS*) of the PV plant. Therefore, the applied *CIERs* should reflect on that proportion of hours per year that the PV plant is operated in its *NGS*. To this extent, the *CIERs* would, most likely, be associated to some demand and energy charges for base load generation (i.e. off-peak or night tariffs). A simple method to calculate the levelized *CIER* rates over the evaluation period is given in (3-6).

$$CIER_{UT} = \sum_{j=1}^{N} [CIER_0 \times (1 + er(j))^{j-1} \times pwf_j] \cdot crf_N \qquad (3\text{-}6)$$

Where $CIER_0$ - *\$/kWh* is an average value of the electricity charge rate (demand + energy) that applies in the first year of the evaluation, $er(j)$ – *p.u* is a nominal constant or variable escalation electricity charge rate (base load) for each year (j) considered in the analysis. The values are levelized through the use of the pwf_j and $crf_{N.}$, as shown in (3-6).

3.2.2 Loss Evaluation Method for Regulated Utilities (*RU*)

3.2.2.1 Proposed TVL

The method proposed for this second case is based on the assumption that a Regulated Utility (*RU*) possesses its own generation and transmission networks. Thus, the Regulated Utility should perceive the PV plant as another generation facility, having though different operational and financial characteristics. The arising question is however, what sort of loss evaluation method should be used to calculate the total ownership of the transformer serving this PV plant? To this end the Regulated Utility could choose to evaluate the losses of such a transformer as it evaluates the losses in any other power transformer installed in its transmission network. This could be achieved by using the methods detailed in Section 1.5.2 or the method proposed in Chapter 2. However, these methods may not reflect the specific conditions that would influence the loss evaluation of a transformer serving a PV plant. Thus, the following should be considered:

a) ***PV Plant Generating States:*** As in Section 3.2.1 (i.e. for independent power producers) the *LL*, *NLL* and *AUX* losses should be capitalised according to the two operating states (*GS* and *NGS*) of the PV plant. In fact during the PV generating state (*GS*), the *NLL* (part), *LL* and *AUX* losses of the transformer would be served locally by the PV energy generation, rather than accounted by any other generation facility of the Regulated Utility that is remotely located.

b) ***Transformer Load and PV Generation Profile:*** The transformer loading coincides (as in *case for IPPs*) to the PV plant's generation profile. Therefore the peak responsibility factor [3] of the PV plant's transformer would be close to unity. This will offer the means to avoid adjusting for the difference between the PV plant's load and the transformer's peak load.

c) ***Energy Component of the Cost of Losses:*** As previously noted nearly all the *LL* and *AUX* losses of the transformer will be served locally by the PV Plant. Thus the present value of the energy (*$/kWh*) that will be used by one kilowatt of loss during the life-cycle of the transformer should be based on the Levelized Cost of Electricity ($LCOE_{PV}$) for PV generation.

d) ***Demand and Energy Component of the Cost of Losses for NLL:*** The *NLL* during the *NGS* of the PV plant should be evaluated as per an appropriate demand (D_{BASE} - *$/kW*) and energy ($E_{BASE}$ - *$/kWh*) charges for the cost of losses. Thus, they should account for the related costs and energy for base load generation. These costs should be classified under the regulated utility's base load generation and transmission expenses (capital and operating), as will be further discussed.

Bearing in mind the above discussion, Figure 3-4 illustrates the PV plant's transformer loss evaluation method proposed for Regulated Utilities. The method accounts for all four conditions (*a-d*) detailed above.

It is obvious that the methodology illustrated in Figure 3-4 is similar to the methodology proposed for the independent power producers (Figure 3-3), as far as the "*PV Element*" is concerned. The fundamental difference arises in the "*System Element*" where the evaluation is based on the Demand (D_{BASE} - *\$/kW*) and Energy (E_{BASE} - *\$/kWh*) components of the cost of losses attributed to the base load generation specifics of the Regulated Utility.

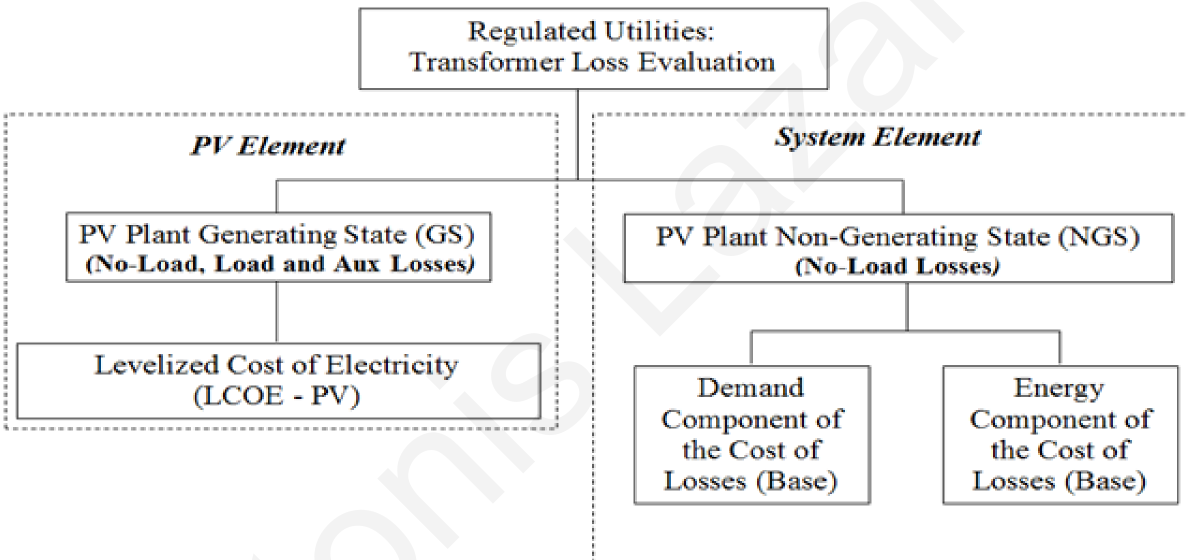


Figure 3-4: Loss Evaluation Method Applicable to Regulated Utilities (*RU*)

Therefore, the Total Value of Losses (TVL_{RU} - *\$*) of a power transformer serving a PV plant that is owned by a Regulated Utility is given in (3-7). Table 3.2 tabulates the further particulars of the nomenclature used in (3-7). The two components D_{BASE} and E_{BASE} appearing in (3-7) are explicitly defined in Table 3.2. A comprehensive method to calculate these two components is presented Chapter 2.

$$TVL_{RU} = CostNLL + CostLL + CostAUX$$

$$\begin{aligned} CostNLL &= N \times f_1(D,E) \times NLL \\ CostLL &= N \times f_2(D,E) \times LL \\ CostAUX &= N \times f_3(D,E) \times AUX \end{aligned} \tag{3-7}$$

$$\Rightarrow f_1(D,E) = \left[D_{BASE} + E_{BASE} \times 8760 \times NGS_{FACTOR} \times AF\right] + \left[LCOE_{PV} \times 8760 \times GS_{FACTOR} \times AF\right]$$
$$\Rightarrow f_2(D,E) = LCOE_{PV} \times PQE^2 \times LLF_{PV} \times 8760 \times GS_{FACTOR}$$
$$\Rightarrow f_3(D,E) = LCOE_{PV} \times FOW \times 8760 \times GS_{FACTOR}$$

Table 3.2
Nomenclature

D_{BASE} (\$/kW)	The annual fixed cost (associated with the generation and transmission category's related expenses of the Regulated Utility) required to serve a kW of loss occurring at the time of the PV plant's non-generating state (e.g. base load demand)
E_{BASE} (\$/kWh)	The annuitized variable cost (associated with generation and transmission category's related expenses of the Regulated Utility) required to serve the energy consumed by the losses occurring at the time of the PV plant's non-generating state (e.g. base load demand).
$LCOE_{PV}$ (\$/kWh)	Solar Photovoltaic Levelized Cost of Electricity as given in (2)
$NGS_{FACTORS}$ (p.u)	Proportion of Hours per year that the PV plant is operated in its Non-Generating State.
GS_{FACTOR} (p.u)	Proportion of Hours per year that the PV plant is operated in its Generating State.
PQE (p.u)	Levelized Annual Peak Load of Transformer as per its life-cycle as given in (4)
LLF_{PV} (p.u)	PV Plant Loss Load Factor as given in (5)
FOW (p.u)	Average hours per year the transformer cooling is operated
AF (p.u)	Availability Factor, the proportion of time in a year that a transformer is predicted to be energized

3.3 Application Example

The proposed methods are numerically evaluated by using a set of realistic data and characteristics. Table 3.3 tabulates the technical and financial specifics of the PV plant considered in this evaluation example.

Table 3.3
PV Plant Specifics

PV Plant Capacity (MW_P)	100
Life – Time Evaluation (years)	30
PV Initial Investment (*IC - M$*)	300
Annuitized Operation & Maintenance Cost (*M$*)	3.9
Annual PV Panels Power Degradation Rate (n_d - *%*) [37]	0.50
Total PV Panels Effective Area (A- m^2) [37]	1055600
PV Module Efficiency (n_{ef} - *%*) [37]	14.70
Annual Solar Potential (kWh/m^2) [33]	1300
Proportion of Hours per year that the PV plant is operated in its Generating State (GS_{FACTOR} - *p.u.*) [33]	0.5064
Proportion of Hours per year that the PV plant is operated in its Non-Generating State (NGS_{FACTOR} - *p.u.*) [33]	0.4936
PV Plant Loss Load Factor (LLF_{PV} - *p.u*) [33]	0.2222
Nominal Discount Rate (d_r - *%*) [21]	10

Thus, by the use of data tabulated in Table 3.3 and the method described in (3-3), the annual calculated PV energy generation for 30 years is shown in Table 3.4.

Table 3.4
Annual Energy Generation

Year	**Calculated PV Energy Generation (*kWh*)**
1	191638902
2	190680707.49
3	189727303.95
4	188778667.43
.	.
.	.
30	165711640.04

Further on, by combining the data provided by both Tables 3.3 and 3.4, as dictated in (3-2) the PV Plant's Levelized Cost of Electricity ($LCOE_{PV}$) is calculated at *0.1784 $/kWh*. A further set of data referring to a suitable step- up transformer is given in Table 3.5. The value of the levelized annual peak transformer losses (PQE^2) can be calculated as defined in (3-4), based on a series of estimates of the transformer's annual peak load, over its life-cycle.

Table 3.5
Transformer Loading and Cooling Characteristics

Transformer Availability Factor (AF – $p.u$) [3]	0.99
Transformer Cooling Operation per year (FOW – $p.u$) [3]	0.30
Initial Transformer Annual Peak Load (Po - $p.u$)	0.80
Levelized Annual Peak Losses of Transformer as per its life-cycle (PQE^2- $p.u$)	0.7164

Finally, Table 3.6 tabulates some example values for $CIER_{UT}$ as well as for Demand (D_{BASE}) and Energy (E_{BASE}) charges that apply to a small scale real system (Section 2.9).

Table 3.6
Example Values of System Charges

D_{BASE} *($/kW)**	140.30
E_{BASE} *($/kWh)**	0.103
Levelized Commercial or Industrial Electricity Rates charged by Supplying Utility ($CIER_{UT}$ - *$/kWh)***)	0.12
*Calculated as per methodology defined in Chapter 2 and evaluated as per the system's characteristics described in Section 2.9 ** Assumed Value	

Hence, the Total Value of Losses (TVL_{IPP} - $) generic formula (3-1) defined for Independent Power Producers (*IPP*) is numerically evaluated as given in (3-8). The process illustrated in (3-8) summarizes the definitions in (1-1), (1-2) and their proposed modification (through the process in Chapter 3) illustrated in (3-1).

Similarly the Total Value of Losses (TVL_{RU} - $) formula (3-7) applicable to a Regulated Utility (*RU*) is numerically evaluated in (3-9). Similarly, the process illustrated in (3-9) summarizes the definitions in (1-1), (1-2) and their proposed modification (through the process in Chapter 3) illustrated in (3-7).

$$TOC_{IPP} = PP + TVL_{IPP}$$

$$TVL_{IPP} = CostNLL + CostLL + CostAUX$$

$$\begin{aligned} CostNLL &= N \times f_1(D,E) \times NLL \\ CostLL &= N \times f_2(D,E) \times LL \\ CostAUX &= N \times f_3(D,E) \times AUX \end{aligned} \tag{3-8}$$

$$\begin{aligned} &\Rightarrow f_1(D,E) = 1297.16\$ / kW \\ &\Rightarrow f_2(D,E) = 125.98\$ / kW \\ &\Rightarrow f_3(D,E) = 237.43\$ / kW \end{aligned}$$

$$TOC_{RU} = PP + TVL_{RU}$$

$$TVL_{RU} = CostNLL + CostLL + CostAUX$$

$$\begin{aligned} CostNLL &= N \times f_1(D,E) \times NLL \\ CostLL &= N \times f_2(D,E) \times LL \\ CostAUX &= N \times f_3(D,E) \times AUX \end{aligned} \tag{3-9}$$

$$\begin{aligned} &\Rightarrow f_1(D,E) = 1365.58\$ / kW \\ &\Rightarrow f_2(D,E) = 125.98\$ / kW \\ &\Rightarrow f_3(D,E) = 237.43\$ / kW \end{aligned}$$

3.3.1 Benchmarking of the Proposed Method

To demonstrate the difference between the system loss evaluation method (Chapter 2) and the PV specific method (3-9) proposed in this chapter, the following example is considered. It is highlighted that system loss evaluation method pertains to "System" unit costs, whereas the PV specific method pertains to PV related costs. In the context of this chapter a "System" includes all power related facilities from generation down to transmission level.

In section 2.9 of this thesis the power transformers loss factors (*NLL* - $f_1(D,E)$, *LL* - $f_2(D,E)$ and *AUX* - $f_3(D,E)$) were evaluated under the specific characteristics of a small-scale real system, where the generation and transmission facilities are possessed by a Regulated Utility (2-31). These loss factors are tabulated in Table 3.7. Thus the Regulated Utility may choose to apply these factors to evaluate the losses of a transformer that is entitled to serve one of its owned PV plants. Alternatively, the utility may choose to utilize the loss factors derived under the PV specific method that is introduced in this paper. These are the loss factors appearing in (3-9) and are also tabulated in Table 3.7.

Table 3.7
Benchmarking of Loss Factors

Loss Factors	System Method (2-31)	PV Specific Method (3-9)
$f_1(D,E)$ ($/kW)	1018.48	1365.58
$f_2(D,E)$ ($/kW)	71.75	125.98
$f_3(D,E)$ ($/kW)	417.62	237.43

To facilitate a valid comparison the loss factors shown in Table 3.7 are applied to a set of an example selling prices (*PP - $*) and guaranteed losses (Table 3.8), assuming that these are the bid offers of different transformer manufacturers. In this example all four bids are assumed to represent size-adequate power transformers with comparable features.

Table 3.8
Example of Selling Prices and Guaranteed Losses

Manufacturer	PP (*$*)	NLL (*kW*)	LL (*kW*)	AUX (*kW*)
A	1325000	50	290	8
B	1315000	53	350	9
C	1305000	61	410	12
D	1340000	45	200	3

Therefore Table 3.9 tabulates the calculated Total Ownership Cost (TOC_{RU}- *$*) of each of the bid offers described above. The results show that when the loss factors of the System Loss Evaluation method (2-31) are applied, the offering from manufacturer B is seen to be the most cost-effective. However, when the loss factors of the PV specific method (3-9) are applied then the offering of manufacturer D appears to be the most cost-effective. Although the absolute values in Table 3.9 should be interpreted with care, as these are quite dependent on the specifics of each PV plant, it is clearly demonstrated that under certain conditions, the Total Ownership Cost of the transformer serving a PV system can be different depending on which method of loss evaluation is applied.

Table 3.9
Evaluation of TOC_{RU} of Transformers

	$T.O.C_{RU}$ ($)	
Manufacturer	**System Method (2-31)**	**PV Specific Method (3-9)**
A	**3395000**	4417803.2
B	38004883.8	4742128.3
C	4201650	5285536.2
D	3459429.2	**3885901.7**

3.3.2 Sensitivity Analysis of Proposed TVL formulation

One of the dominant factors in the loss evaluation method proposed in this paper is the Levelized Cost of Electricity ($LCOE_{PV}$ - $/kWh$) for PV generation. This is because the $LCOE_{PV}$ relies on the PV energy output as determined by the available solar resources (i.e. the annual solar potential - kWh/m^2).

To address this influence, a sensitivity analysis is performed to illustrate the percent variation in the calculated loss factors (NLL - $f_1(D,E)$, LL - $f_2(D,E)$ and AUX - $f_3(D,E)$) over a range of different annual solar potential values (kWh/m^2). Hence, Figure 3-5 illustrates the percent change in the calculated loss factors that apply for the regulated utility case study (3-7). These are the loss factors appearing in (3-9) and have been calculated for an annual solar potential of $1300\ kWh/m^2$.

The results in Figure 3-5, (which are benchmarked over the $1300\ kWh/m^2$ case), show that the $f_2(D,E)$ and $f_3(D,E)$ loss factors are identically reliant on the annual solar potential, while the $f_1(D,E)$ factor is less influenced. For example there is a +36% increase in the $f_2(D,E)$ and $f_3(D,E)$ loss factors when the available annual solar potential changes from $1300\ kWh/m^2$ to $972\ kWh/m^2$. In the case of the $f_1(D,E)$ loss factor a +20% change is observed. This is expected, since the $f_2(D,E)$ and $f_3(D,E)$ are heavily influenced by the calculated $LCOE_{PV}$ value. The $f_1(D,E)$ loss factor is less influenced owing to the fact that is partly determined by some of the regulated utility's demand and energy components of the cost of losses. These components are independent from the available annual solar potential.

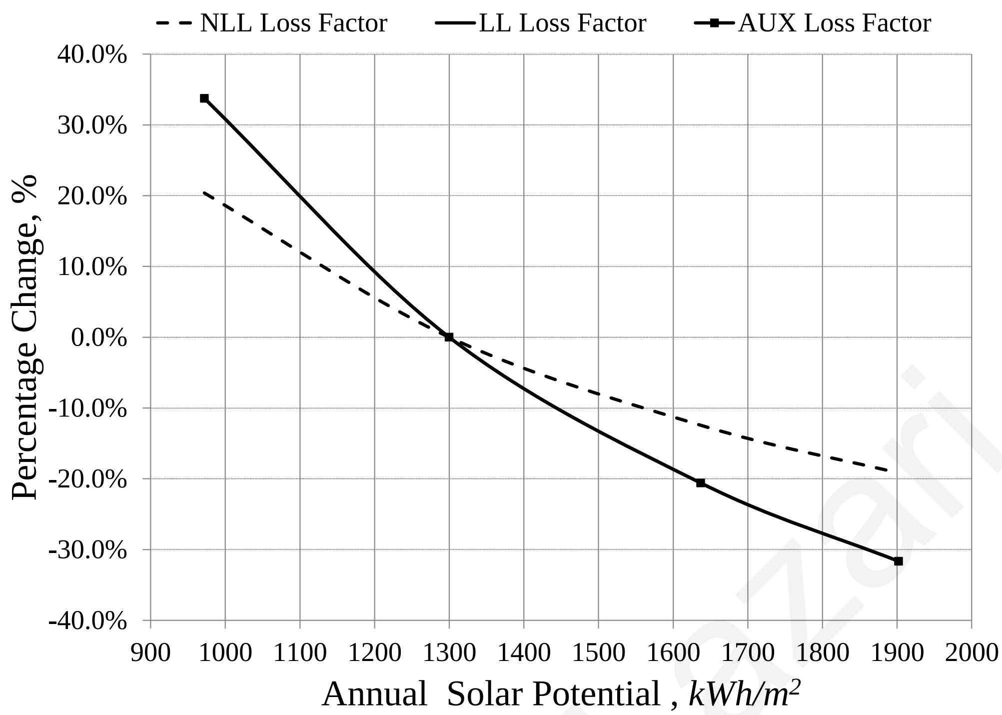


Figure 3-5: Influence of Annual Solar Potential on Calculated Loss Factors

Finally, it can be shown that under the same conditions tabulated in Tables 3.3 – 3.6, but with an annual solar potential of *1902 kWh/m*^{2} (instead of *1300 kWh/m*^{2}), the most cost effective offering, out of those tabulated in Table 3.8, changes (see Table 3.9 – 3rd column) from manufacturer D to manufacturer A.

4

Probabilistic Total Ownership Cost of Transformers Serving Large-Scale Wind Plants in Liberalized Energy Markets

4.1 Introduction

4.1.1 General Remarks

Chapter 3 has addressed the fact that when transformers are obliged to serve an intermittent PV energy source, these set a special case when it comes to evaluate their life-cycle losses and total ownership costs. However, some further modifications are needed to account for an appropriate loss evaluation method of transformers serving other renewable energy sites. This is because the energy generation profile and characteristics of a PV plant for example, are very different to the specifics of a Wind Farm. More specifically, the generation profile of a wind farm is extremely volatile and may have multiple ON and OFF states during a day. In a liberalized energy market the hourly profile of wholesale electricity prices may vary significantly, thus complicating the capitalisation of losses of transformers serving such an unbalanced energy source. To this end, Chapter 4 defines a probabilistic, life-cycle loss evaluation method to evaluate the Total Ownership Cost of power transformers that are obliged to exclusively serve large wind plants. The method introduced, responds to the ongoing efforts of developing risk and cost-based decision making processes in today's competitive and dynamic energy markets. Therefore, capitalizing the losses and consequently the ownership cost of transformers, serving intermittent wind energy sources, entails a probabilistic approach that integrates the financial and technical characteristics as well as the uncertainties of wind energy generation.

4.1.2 Loss Evaluations Methods and Renewable Energy Penetration (Wind Generation)

Following the discussion in Chapter 3 (Section 3.1.2), it should be reiterated that in the light of disintegrated electricity markets and renewable energy penetration, estimating the *TVL* of power transformers becomes more complex. Following this, it should be highlighted that a major knowledge gap in transformers' loss evaluation methods, relates to transformers which are entitled to exclusively serve large renewable plants that participate in an electricity market.

To this extent it is argued that there cannot be a uniform loss evaluation method for transformers serving all kind of renewable energy sites. This is because the energy generation profile and characteristics of a PV plant for example, are very different to the specifics of a Wind Farm. The main difference, in the case of large scale wind farms, that critically influences the loss evaluation method pertains to the generation profile of the wind farm. The arising complications are as follows:

a) The generation profile of a PV plant can be broadly classified in one of two different "states" (GS + NGS). However, the generation profile of a wind farm is more volatile and may have multiple ON and OFF states during a day (24 hours).

b) The losses of the transformer serving the wind plant, can be appropriately capitalized when accounting for the following:

    a. What percent of time (in a day and subsequently in a year) the wind park is able to cover its own energy needs and losses, as well as to supply energy to the collector grid?

    b. What percent of time (in a day and subsequently in a year) the wind park needs to cover its auxiliary needs and losses from the main grid supply (i.e. buy energy from a supplying utility, when its generation potential is low)?

    c. The time interval of the above defined percent (i.e. when is it taking place during a day?) is very important. This is because in a liberalized energy market the hourly profile of wholesale electricity prices may vary significantly, thus complicating the capitalization of losses of the transformer especially when the Wind Park is not generating.

Following the above discussion, it is extracted that the *TVL* of power transformers serving large-scale wind plants in a liberalized energy markets can be evaluated when identifying the proportion in time (within a year) that the wind plant is able to cover the losses of its serving transformers. This will subsequently determine the remaining time proportion, where purchased energy from an electricity market is needed, to cover the transformer losses. The latter will occur when the generation potential of the wind plant is negligible.

Towards identifying these proportions, one should also note that the duration (how long) and the occurrence (when) of the "ON" and "STAND-BY" states within a day is crucial. This is because in a liberalized energy market the hourly as well as the yearly profile of the wholesale markets' electricity prices may vary significantly, thus complicating the capitalization of transformer losses. The complication is profound in the case where the wind plant is kept at "hot-standby" (i.e. not generating any power) and therefore purchased energy should be used to cover for transformer losses.

Therefore, capitalizing the losses and consequently the ownership cost of transformers serving intermittent wind energy sources entails a probabilistic framework that integrates the financial and technical characteristics as well as the uncertainties of wind energy generation.

4.2 Theoretical Discussion of Proposed Method

The overall objective of this Chapter is to appropriately modify the classical *TVL* formula shown in (4-1), to account for the special circumstances dictated by wind energy generation specifics in a liberalized market environment. However, modifying the classical formulation shown in (4-1) entails understanding and integrating the characteristics of wind energy generation as well as some relevant characteristics of liberalized energy markets.

$$TVL = CostNLL + CostLL + CostAUX$$

$$\begin{aligned} CostNLL &= f_1(D,E) \times NLL \\ CostLL &= f_2(D,E) \times LL \\ CostAUX &= f_3(D,E) \times AUX \end{aligned} \tag{4-1}$$

The proposed methodology renders the formulation process relatively simple and sequential, by capitalizing on data that wind plant owners/operators already possess. Thus, the data used in the probabilistic *TOC* formulation proposed are no different than the data required to perform a techno-economic feasibility study for Wind Plants' operation business. These data include:

a) Historical wind speed data.

b) Historical wholesale market prices.

c) Technical and financial characteristics of the wind plant including fixed and operating expenditure.

4.2.1 Wind Plant Operating States Definition

Through a certain time interval (e.g. a day) the wind plant will randomly operate in one of two different states. When operated in its ON state (*ONS*), the wind plant will be responsible to cover its own energy needs and losses, as well as to supply energy to the transmission grid. When operated in its STAND-BY state (*STBS*), the auxiliary energy needs and losses of the plant should be covered from a market supplier that provides energy at a variable cost rate.

Therefore, the same fundamental principles would apply when capitalizing (i.e. estimating the *TVL - $*) the losses of the transformers serving the wind plant. That is, the transformers' losses should be evaluated and subsequently capitalized as per the two operating states, namely *ONS* and *STBS*. The two different operating states of a wind plant (*ONS & STBS*), shown in Figure 4-1, will concurrently facilitate the proposed loss evaluation method to rely on two elements. These are defined as: a) "*Wind Plant Element*" and b) "*Market Element*". Therefore, when the wind plant is likely to be on its *ONS*, the proposed loss evaluation will rely on the financial specifics associated with the "*Wind Plant*". In contrast, when the wind plant is likely to be on its *STBS*, the proposed loss evaluation will rely on the financial specifics associated to the "*Market*".

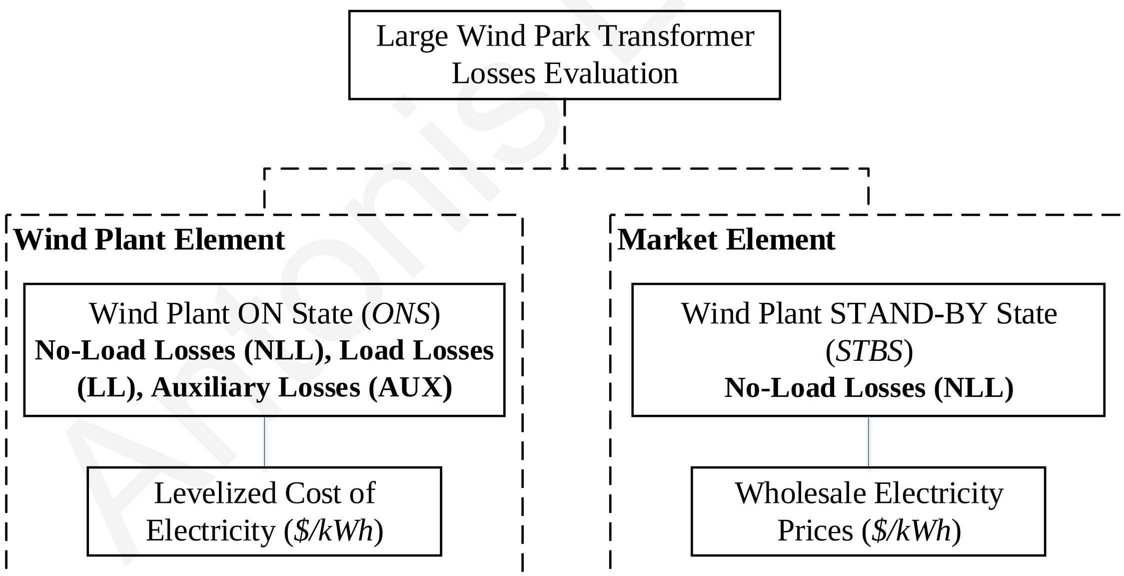


Figure 4-1: Outline of Proposed Loss Evaluation Method (Wind Plant Transformers' Loss Evaluation Method)

In particular, Figure 4-1 suggests that the no-load losses (*NLL - kW*) of the transformer should be evaluated under a probability that defines whether the wind park is on its *ONS* or *STBS*. The load losses (*LL - kW*) and the auxiliary losses (*AUX - kW*) may be evaluated under the "*Wind Plant Element"* only. This is because the *LL* and *AUX* losses will be dominant during the generating state (*ONS*) of the wind plant. The latter may be verified by assessing the ratio of the total exported energy during the generating state (*ONS*) to the total imported energy during the stand-by state (*STBS*) of the wind plant.

The "*Wind Plant Element*" reflects on financial data which describe the overall costs of the wind plant distributed over its lifetime (i.e. Wind Energy Related - Levelized Cost of Electricity – $LCOE_{Wind}$ - *\$/kWh*). In contrast, when the wind plant is likely to be on its *STBS*, the proposed loss evaluation will rely on the "*Market Element*". In such a case, the loss evaluation process should be based on the variable energy cost rates offered by a market supplier, over the life-cycle of the transformer.

Therefore, under the above described framework the classical formulation shown in (4-1) may be preliminary modified as given in (4-2). Table 4.1 tabulates the further particulars of the nomenclature used in (4-2).

$$
\begin{gathered}
TVL = CostNLL + CostLL + CostAUX \\
\Rightarrow CostNLL = N \times \left[f_{1_{STBS}}(D,E) \times P(STBS) + f_{1_{ONS}}(D,E) \times P(ONS) \right] \times NLL \\
\Rightarrow CostLL = N \times f_{2_{ONS}}(D,E) \times P(ONS) \times LL \\
\Rightarrow CostAUX = N \times f_{3_{ONS}}(D,E) \times P(ONS) \times AUX
\end{gathered}
\tag{4-2}
$$

Table 4.1
Nomenclature

***P(STBS) (p.u)**	Empirical Probability that defines whether the Wind Plant will be on its STAND-BY State (*STBS*)
***P(ONS) (p.u)**	Empirical Probability that that defines whether the Wind Plant will be on its ON State (*ONS*)
f_{1STBS} **(\$/kW)**	Loss Evaluation Factor that capitalizes or converts no-load loss costs, which are attributed to STAND-BY State (*STBS*), to present value.
f_{1ONS} **(\$/kW)**	Loss Evaluation Factor that capitalizes or converts no-load loss costs, which are attributed to ON State (*ONS*), to present value.
f_{2ONS} **(\$/kW)**	Loss Evaluation Factor that capitalizes or converts load loss costs which are attributed to ON State (*ONS*), to present value.
f_{3ONS} **(\$/kW)**	Loss Evaluation Factor that capitalizes or converts auxiliary load loss costs, which are attributed to ON State (*ONS*), to present value.
NLL (kW)	Losses that are generated by the transformer core upon energisation of the unit. These losses are independent of the amount of load that is put on the transformer. Most common types of no load losses include hysteresis (type of core steel) and eddy currents (core construction methods).
LL (kW)	Losses that are generated by the transformer windings and varied by the amount of load present on the transformer. Normally called "I^2R losses" associated with size, length and geometry of the winding construction.
AUX (kW)	Auxiliary power lost by the operation of transformers' cooling units.
*** P(STBS) + P(ONS) = 1***	

4.2.2 Loss Evaluation Factors Definition

The generic formulation shown in (4-2) contains the Loss Evaluation Factors (f_{1STBS}, f_{1ONS}, f_{2ONS} and f_{3ONS}) and the empirical probabilities, *P(STBS)* and *P(ONS)* that statistically define the operation status of the wind plant. Table 4.1 associates the evaluation of all terms found in (4-2) to the "*Wind Plant Element*" and the "*Market Element*" elements respectively.

Table 4.2
Terms Definition

P(STBS((p.u)	"*Market Element*"
P(ONS) (p.u)	"*Wind Plant Element*"
f_{1STBS} **($/kW)**	"*Market Element*"
f_{1ONS} **($/kW)**	"*Wind Plant Element*"
f_{2ONS} **($/kW)**	"*Wind Plant Element*"
f_{3ONS} **($/kW)**	"*Wind Plant Element*"

4.2.2.1 *P(ONS)* and *P(STBS)* Definition

The data required to calculate *P(ONS)* and *P(STBS)* rely on historical wind speed data and wind turbines' characteristic power curves. Towards identifying the required empirical probabilities, the historical wind speed data should be correlated to the wind turbines' power curve. This correlation will provide an empirical historic distribution of the power-output duration curve [40]. This empirical historic distribution may be subsequently used as a predictive distribution for the wind plants' power-output duration curve. By means of an example, Figure 4-2 illustrates an empirical annual power-output duration curve, obtained from historical data [41]. It specifically illustrates that the wind plant considered has roughly a 78% probability to be in the *ONS* – *P(ONS)* ~ 0.78 and a 22% probability to be in the *STBS* - *P(STBS)* ~ 0.22.

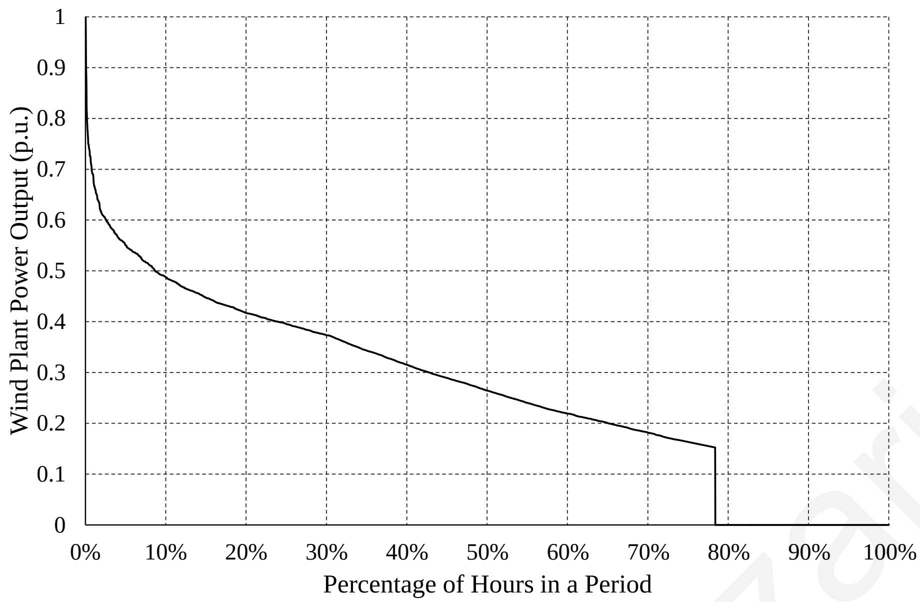


Figure 4-2: Historical Wind Plant Power – Output Duration Curve

4.2.2.2 f_{1STBS} Formulation

The f_{1STBS} - *\$/kWh* is the loss evaluation factor that capitalizes or converts the no-load loss (*NLL – kW*) costs of the transformer to present value. Since f_{1STBS} should reflect on the *"Market Element",* its formulation should embrace the variable energy cost rates offered by a market supplier, over the life-cycle of the transformer. The proposed formulation for A_{STBS} is shown in (4-3).

$$f_{1_{STBS}} = [MP_{STBS}] \times 8760 \times AF \tag{4-3}$$

Within (4-3), *AF - p.u* reflects on the Availability Factor of the transformer, i.e. the proportion in time (e.g. 1 year) that the transformer remains energized. $[MP_{STBS}]$ - *\$/kWh* refers to an array of wholesale energy Market Prices that are likely to be paid to a supplier over the life-cycle of the wind plant. That is, for capitalizing the associated portion of the *NLL* that falls under the *STBS* of the wind plant. Therefore, the applied $[MP_{STBS}]$ should reflect on the energy prices that reflect in those hours per period (e.g. 1 year) that the wind plant is likely to be on its *STBS*.

To this extent, it is noted that the profile of the wholesale electricity prices may vary significantly within a specified period (e.g. a year). Therefore, the $[MP_{STBS}]$ array may contain a range of wholesale market electricity charges (*\$/kWh*). It can therefore take the form of a probability density function - $f\left(MP_{STBS};\overline{\mu_E},\sigma_E^2\right)$, resulting from historical data. For simplicity, it may be assumed that the same distribution of *[MP_{STBS}]* will hold over a future evaluation period albeit integrating the effect of future inflation on the level of energy prices. That is to include the effect of inflation on the mean value of energy prices ($\overline{\mu_{Ej}}$) in each year *j* of the evaluation period, but to maintain their distribution (σ_{Ej}) constant as illustrated in (4-4).

$$\overline{\mu_{Ej}} = \overline{\mu_E} \times (1 + IR(j))^{j-1}$$
$$\sigma_{Ej} = \sigma_E \tag{4-4}$$

Where, *j* is the year considered in the transformer lifetime *N*, *IR(j)* reflects an annual constant or variable inflation rate for the *N* years considered in the analysis, $\overline{\mu_E}$ is the mean value of the probability density function resulting from historical energy prices and σ_E is the standard deviation of these prices as results from the statistical treatment of historical data. The latter will remain constant in every year *j* of the evaluation (i.e. $\sigma_{Ej} = \sigma_E$). Thus, $\overline{\mu_{Ej}}$ is the mean value of the inflated energy prices for each year *j* considered over the evaluation period *N*. To this extent the proposed formulation for a levelized probability density function for energy market prices associated to *STBS*, $f(MP_{STBS}; \overline{\mu_{LE}}, \sigma_E^2)$ is shown in (4-5).

$$f(MP_{STBS}; \overline{\mu_{LE}}, \sigma_E^2) = f\left(MP_{STBS}; \left\lfloor \sum_{j=1}^{n} \left(\overline{\mu_{Ej}} \times pw_j\right) \times crf_N \right\rfloor, \sigma_E^2\right) \tag{4-5}$$

Where, $\overline{\mu_{LE}}$ is the levelized mean value of the future probability density functions for each year *j* considered in the evaluation period *N*, pw_j is the present worth factor of each year as per a nominal discount rate [3] and crf_N is the capital recovery factor.

4.2.2.3 f_{1ONS} Formulation

Moving further, the f_{1ONS} - *\$/kWh* loss evaluation factor should reflect on the *"Wind Plant Element"*. The proposed formulation for f_{1ONS} is shown in (4-6).

$$f_{1_{ONS}} = LCOE_{Wind} \times 8760 \times AF \tag{4-6}$$

Within (4-6) the f_{1ONS} formulation integrates the Wind Energy related Levelized Cost of Electricity ($LCOE_{Wind}$ *-\$/kWh*) shown in (4-7). This is because the $LCOE_{Wind}$ can account for a) the cost of wind capacity to serve the power used by the losses (while the plant is in its *ONS*) and b) the value of the wind energy that will be used by one kilowatt of loss during the life-cycle of the plant under study.

$$LCOE_{Wind} = \frac{IC}{\sum_{j=1}^{N} EG_j \times pwf_j} + \frac{\sum_{j=1}^{N} OM_j \times pwf_j}{\sum_{j=1}^{N} EG_j \times pwf_j} \quad (4\text{-}7)$$

Within (4-7), N refers to the life-cycle of the wind plant in years, IC is the initial investment cost in *\$*, OM_j (*\$*) are the annual operation and maintenance costs and EG_j (*kWh/MWh/GWh*) is the expected wind energy generation for each evaluation year, that results from the correlation of the wind speed data to the wind turbine's power curve [40].

4.2.2.4 f_{2ONS} Formulation

The f_{2ONS} - *\$/kWh* is the loss evaluation factor that capitalizes or converts the load loss costs of the transformer which are attributed to ON State (*ONS*), to present value. As previously noted in Table 4.2, f_{2ONS} formulation should be associated to the "*Wind Plant Element*", as given in (4-8).

$$f_{2_{ONS}} = LCOE_{Wind} \times 8760 \times LLF \times PUL^2 \quad (4\text{-}8)$$

Where, $LCOE_{Wind}$ (*\$/kWh*) refers to the Wind Energy related Levelized Cost of Electricity defined in (4-7), LLF (*p.u*) to the Wind Plant Loss Load Factor and PUL (*p.u* – Table 1.2) to the peak-per-unit load of the transformer [3]. The LLF is defined as the ratio of the wind plant's average power loss ($L_{average}$ - *MW*) to the wind plant's peak power loss (L_{peak} - *MW*) over a given period of time (*T – hours/days etc.*) as in (4-9). In the absence of any measured loss values for ($L(t)$ - *MW*), it may be assumed that the Wind Plant's losses are proportional to the square of the Wind plant's generation load (P_w - *MW*).

$$LLF = \frac{L_{average}}{L_{peak}} = \frac{\int_0^T L(t)dt}{L_{peak} \times T} \approx \frac{\int_0^T [P_W(t)]^2 dt}{(P_{W\,PEAK})^2 \times T} \quad (4\text{-}9)$$

The peak-per-unit load of the transformer as per its life-cycle *(PUL – p.u)* is calculated based on the following two assumptions:

a) The transformer maximum loading (Pt_j - MW) is coincident to the Wind plant's maximum power output.
b) The Wind plant's power output (P_w - MW) is subject to wind turbines' power output characteristics.

Thus, PUL (p.u) [3] results from the ratio of the average of the estimated annual peak loads of the transformer throughout its life-time, divided by the transformer rated capacity. PUL concurrently accounts for the peak-per-unit losses ($PUL^2 - p.u$) as given in (4-10).

$$PUL^2 = \frac{\sum_{j=1}^{N} Pt_j^2}{N \times P_{rated}^2} \tag{4-10}$$

Within (4-10), j is the year considered in the transformer lifetime N, Pt_j is the estimated annual transformer peak load in MW, which may concurrently account for the annual transformer peak losses (Pt_j^2 - MW), and P_{rated} is the transformer rated capacity in MW.

4.2.2.5 f_{3ONS} Formulation

Finally, the f_{3ONS} - $\$/kWh$ formulation is given in (4-11). This formulation is able to capitalize the auxiliary load loss ($AUX - kW$) costs, which are attributed to ON State (ONS), to present value.

$$f_{3_{ONS}} = LCOE_{Wind} \times 8760 \times FOW \tag{4-11}$$

Where, $LCOE_{Wind}$ refers to the Wind Energy related Levelized Cost of Electricity ($\$/kWh$) defined in (4-7), and FOW ($p.u$) to the average hours per year that the transformer cooling is operated.

4.2.3 Proposed Probabilistic TVL and TOC Evaluation

Following the derivation of concepts in the previous sections, the generic formulation in (4-1) is appropriately modified to accommodate wind energy generation characteristics in loss evaluation processes. Using the defined Loss Evaluation Factors (f_{1STBS}, f_{1ONS}, f_{2ONS} and f_{3ONS}) and the empirical probabilities, $P(STBS)$ and $P(ONS)$, the proposed TVL formulation, as was preliminary defined in (4-2), takes the form of a probability density function (4-12). This provides a distribution of the power transformer's value of losses, $f(TVL,\mu,\sigma^2)$, over its life.

$$TVL = CostNLL + CostLL + CostAUX$$
$$CostNLL = N \times \left[f_{1_{STBS}}(D,E) \times P(STBS) + f_{1_{ONS}}(D,E) \times P(ONS) \right] \times NLL$$
$$CostLL = N \times f_{2_{ONS}}(D,E) \times P(ONS) \times LL$$
$$CostAUX = N \times f_{3_{ONS}}(D,E) \times P(ONS) \times AUX$$

$$\Rightarrow TVL = f(TVL;\mu,\sigma^2)$$
$$\Rightarrow f_{1_{STBS}}(D,E) = f\left(MP_{STBS};\overline{\mu_{LE}},\sigma_E^2\right) \times 8760 \times AF$$
$$\Rightarrow f_{1_{ONS}}(D,E) = LCOE_{Wind} \times 8760 \times AF$$
$$\Rightarrow f_{2_{ONS}}(D,E) = LCOE_{Wind} \times 8760 \times LLF \times PQE^2$$
$$\Rightarrow f_{3_{ONS}}(D,E) = LCOE_{Wind} \times 8760 \times FOW \tag{4-12}$$

The *TOC* of a transformer is therefore defined by the purchase price (*PP - $*) of the transformer plus its *TVL* as given in (4-13). The *TVL* associated formulation is given in (4-12).

$$TOC = PP + f(TVL;\mu,\sigma^2)$$
$$\Rightarrow TOC = f(TOC;\mu,\sigma^2) \tag{4-13}$$

4.3 Application Example

The proposed probabilistic $f(TVL;\mu,\sigma^2)$ - *$* (4-12) and the subsequent probabilistic $f(TOC;\mu,\sigma^2)$ - *$* (4-13) is numerically evaluated by using a set of real operational and financial data. Table 4.3 tabulates the technical and financial specifics of the wind plant considered in this evaluation example.

Table 4.3
Wind Plant Specifics

Wind Plant Capacity (*MWp*)	120
Number of Wind Turbine Generators (*2MW each*)	60
Life – Time Evaluation (*years*)	30
Wind Capital Investment (*CI - M$*)	185
Annuitized O&M Cost – Year 1..10 (OM - *M$*) [42]	1.4
Annuitized O&M Cost – Year 11..30 (0M - *M$*) [42]	2.8
Wind Plant Array Efficiency (η_{α} - *%*)	90
Annual Inflation Rate (IR_y - *%*)	1.40
Nominal Discount Rate (d_r - *%*) [21]	10
Wind Turbine Output Curve -2MW (Vestas)	[43]
Loss Load Factor Wind Plant (*LLF – p.u.*)	0.1615

Annual Wind Energy Generation (EG_j - GWh)	225,52
Wind Related Levelized Cost of Electricity ($LCOE$ - $\$/kWh$)	0.0875

4.3.1 Evaluation of Annual Wind Energy Generation (EG_j)

Figure 4-3, illustrates the wind speed frequency distribution curve as obtained from historical wind speed measurements [41]. In particular, the curve pertains to eleven years (2004-2015) of wind speed data. It is assumed that the wind speed historic distribution shown in Figure 4-3 can be used as a predictive wind speed distribution over the life-cycle of the wind plant. To this extent, the expected annual wind energy generation (EG_j - GWh) can be estimated by combining the distribution in Figure 4-3, to the wind turbines' power curve [43], as per the standard method described in [40]. Thus, under the specifics considered, EG_j will result in *225.52GWh*. This value will be constantly applying in each year *j* considered in the evaluation.

The empirical annual power-output duration curve, as per the historical data [41] is shown in Figure 4-2. As already been report (Section 4.2.2.1), the historical analysis provides a 78% probability for the wind plant to be in the ONS – *P(ONS)* ~ 0.78 and a 22% probability to be in the STBS - *P(STBS)* ~ 0.22.

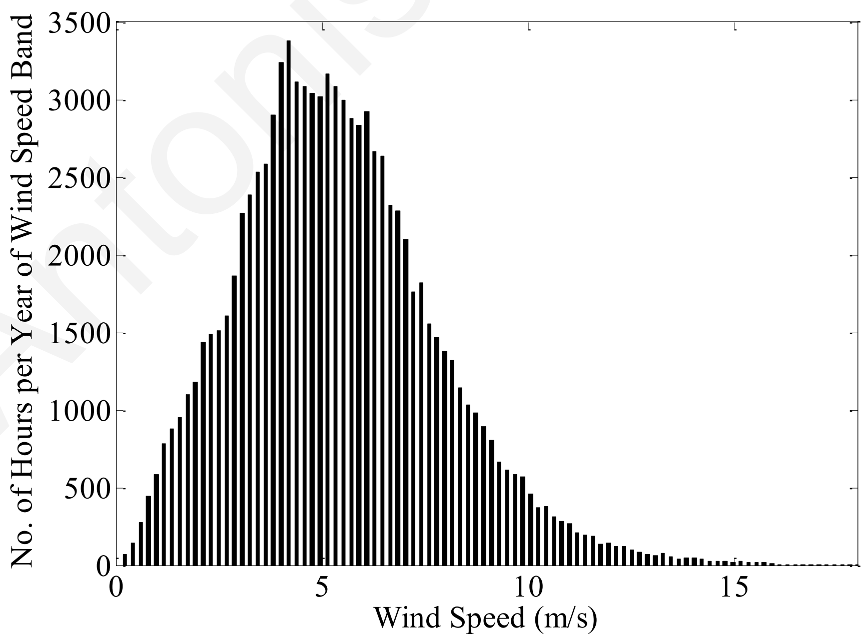


Figure 4-3: Wind Speed Frequency Distribution Curve

4.3.2 Evaluation of Wholesale Market Prices

The statistical evaluation of the historical wholesale market prices pertains to a set of available data [44]. These data, ranging from 2010-2015, include hourly wholesale energy prices in *$/MWh*. The wholesale energy prices should be subsequently correlated to the historical wind speed hourly data during the same four year period 2010-2015. This correlation is necessary to determine which wholesale energy prices correspond to the STBS of the wind plant (i.e. $[MP_{STBS}]$ - *$/MWh*). The STBS is assumed to hold for wind speed values lower than *3m/s* [43]. The process is illustrated in Figure 4-4 for a sample of 24 hours data.

Thus, by processing the whole set of data, ranging from 2010-2015, following the method shown in Figure 4-4, a probability density function (*pdf*) of the wholesale energy prices corresponding to STBS, is deduced. Figure 4-5, in particular, shows the probability density function $f\left(MP_{STBS};\overline{\mu_E},\sigma_E^2\right)$ resulting from the data processing.

The probability density function of Figure 4-5 can be used to describe the distribution of future energy prices.

Following the principles described in Section 4.2.2.2, and the formulation given in (4-4), a probability density function for each subsequent year considered in the analysis is deduced. For clarity, Figure 4-6 shows the probability density functions obtained for a sample of future years. Thus, for each subsequent year in a future evaluation period, the *pdf* distribution (σ_E) remains constant, whereas the mean value (μ_{Ej}) is subject to an annual (j) inflation rate in the order of 1.4%. Using the formulation shown in (4-5) the levelized probability density function, $f(MP_{STBS};\overline{\mu_{LE}},\sigma_E^2)$ can be calculated. This is also marked in Figure 4-6.

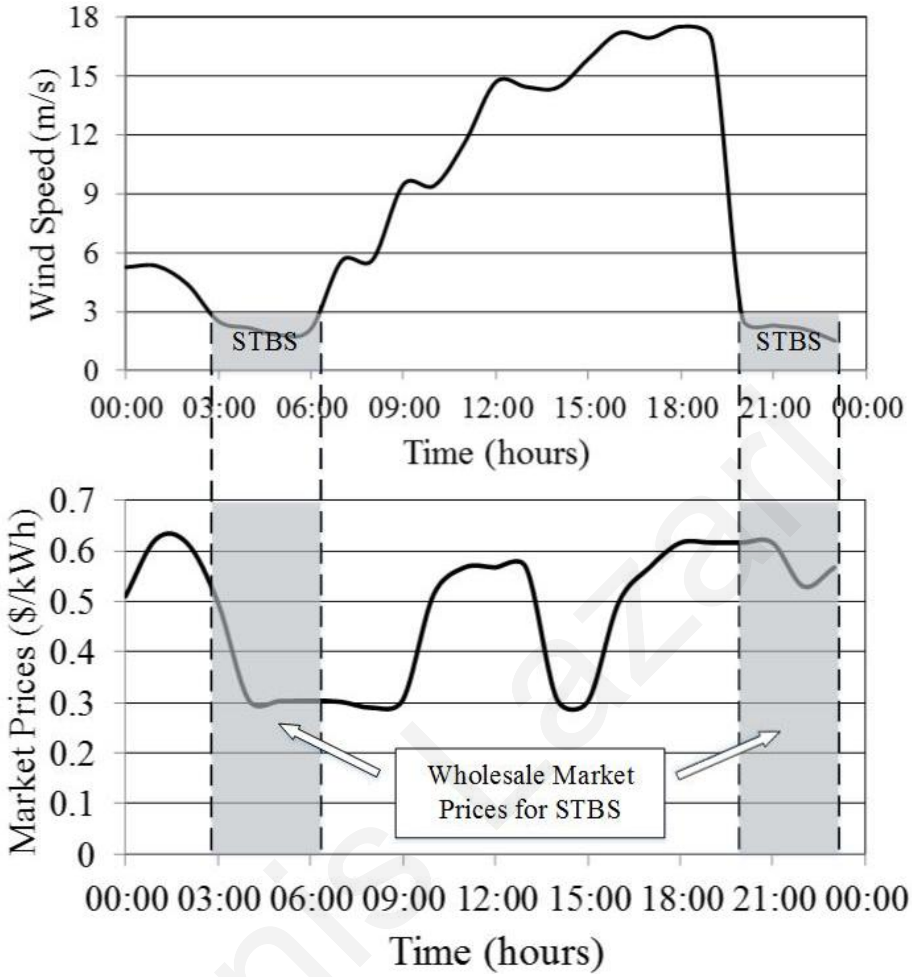


Figure 4-4: Correlation of STBS of Wind Plant to Wholesale Energy Prices

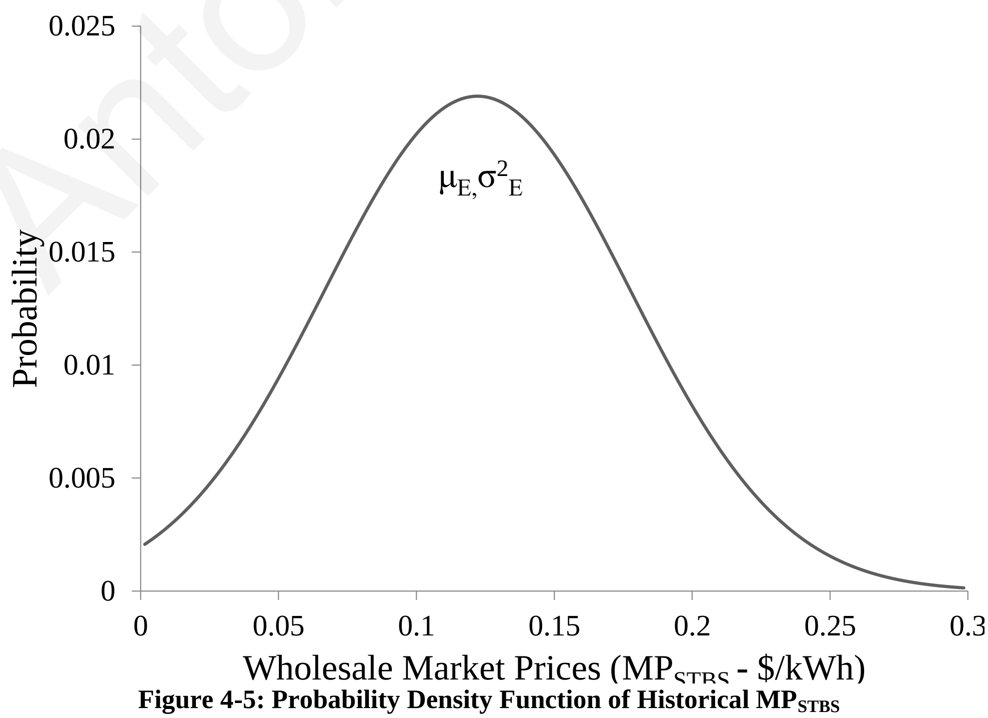


Figure 4-5: Probability Density Function of Historical MP_{STBS}

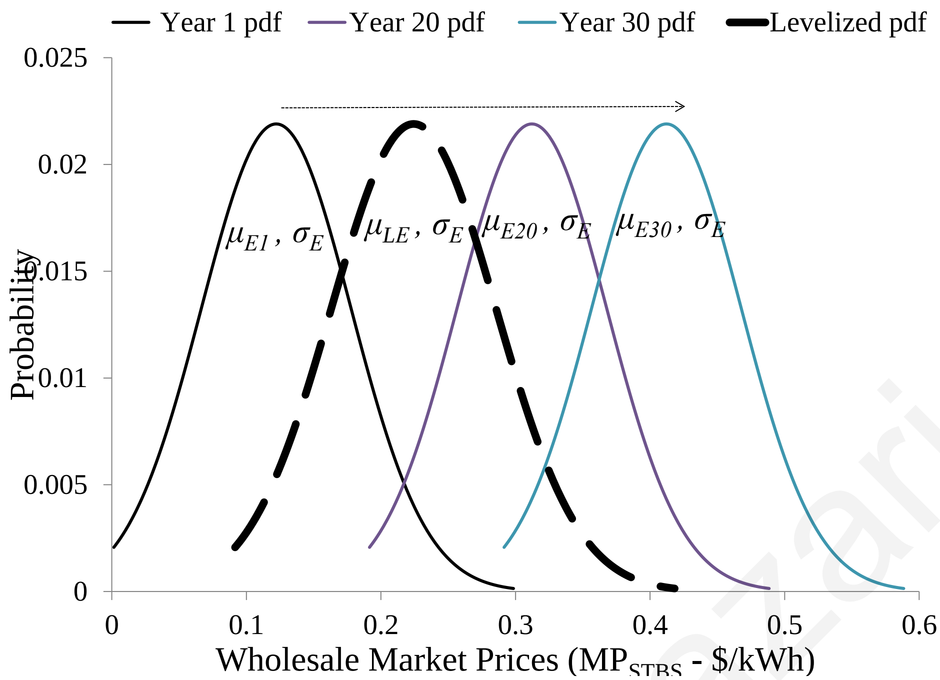


Figure 4-6: Probability Density Function of Future MP_{STBS}

4.3.3 Power Transformer Specifics

Table 4.4 tabulates the operational specifics of a power transformer serving the wind plant's specifics (Table 4.3) [45].

Table 4.4
Transformer Loading and Cooling Characteristics

Transformer Estimated Purchase Price (*$*)	1305000
Transformer Guaranteed No- Load Losses (*NLL - kW*)	61
Transformer Guaranteed Load Losses (*LL - kW*)	410
Transformer Guaranteed Auxiliary Load Losses (*AUX - kW*)	12
Transformer Availability Factor (*AF – p.u*) [3]	0.99
Transformer Cooling Operation per year (*FOW – p.u*)	0.20
Initial Transformer Annual Peak Load (*Po - p.u*)	0.75
Levelized Annual Peak Losses of Transformer as per its life-cycle (PUL^2- *p.u*)	0.6187

4.3.4 Total Ownership Cost Distribution

Thus, Figure 4-7 illustrates the Total Ownership Cost distribution ($f(TOC;\mu,\sigma^2)$ - *$*) for the referenced transformer by numerically evaluating (4-12) and (4-13). The *TOC* is illustrated in the form of a statistical boxplot [46] and its equivalent *pdf*. Statistical boxplots provide the distributional characteristics of a group of values as well as the level of these values. Thus, Figure 4-7 shows the distribution of *TOC* values, by embracing the uncertainties of wind energy generation and wholesale market prices.

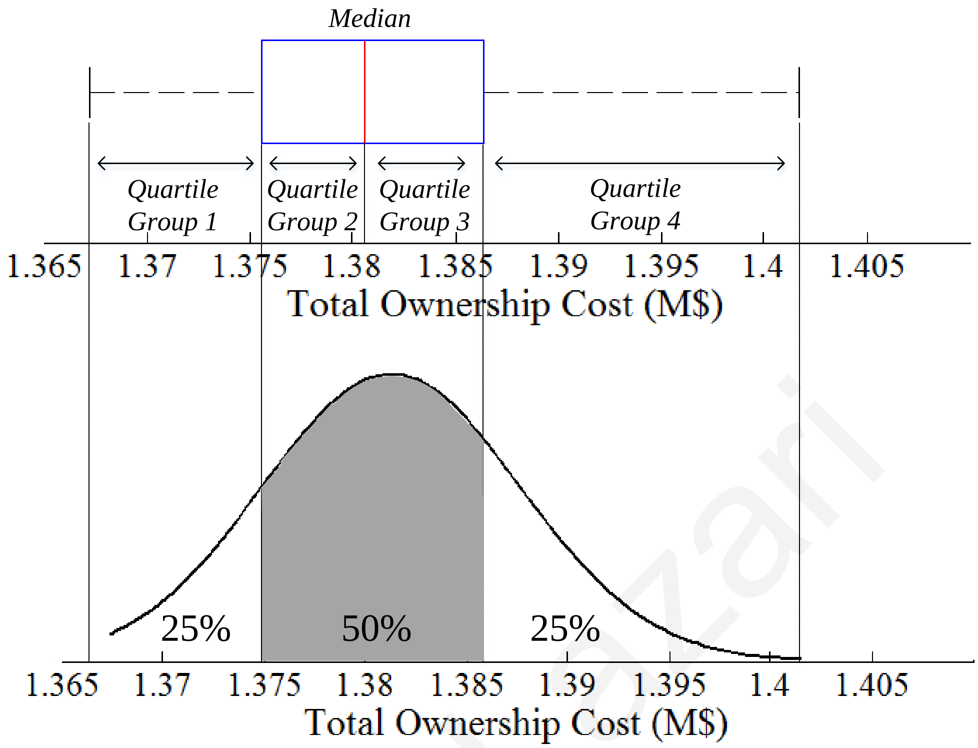


Figure 4-7: Total Ownership Cost Distribution (*f(TOC;μ,σ*^{2}*) - $*)

Figure 4-7, in particular illustrates the *TOC* distribution in the form of boxplot quartiles groups: a) quartile group 1; *TOC* ranging from 1.368M$ to 1.3705M$, b) quartile group 2; *TOC* ranging from 1.3705M$ to 1.3805M$, c) quartile group 3; *TOC* ranging from 1.3805M$ to 1.386M$ and quartile group 4; *TOC* ranging from 1.386M$ to 1.402M$. Reference to Figure 4-7, a quartile group has a 25% mass probability to occur. Following this, narrower quartile groups mean higher probability for each individual value in the equivalent group. *TOC* values ranging in the 2nd and 3rd quartile concentrate a higher probability to be observed than those in 1st and 4th quartile. This is evident by inspecting the individual quartile group width. The median value (1.3806*M$*) relates to the *TOC* value lying at the midpoint of the *TOC* distribution. It thus specifies an equal probability for the *TOC* values to fall above or below this median value.

4.3.5 Sensitivity Analysis of Proposed TOC formulation

A key factor in the loss evaluation method proposed in this paper is the Wind related Levelized Cost of Electricity ($LCOE_{Wind}$ - *$/kWh*). The *LCOE* reflects on the Wind plant energy output, as this is correlated to the available wind speed data (i.e. the annual wind energy potential). To address this effect, a sensitivity analysis is performed to illustrate the variation in the transformer's *TOC* distribution ($f(TOC;\mu,\sigma^2)$ - *$*) for a low annual wind potential profile and a high annual wind potential profile. To facilitate a valid comparison the subsequent sensitivity analysis relies on the same technical and financial specifics shown in Tables 4.3 and 4.4, albeit to different annual wind potential frequency distribution curves. To this end, Figure 4-8 shows a frequency distribution curve pertaining to a wind potential lower than that of Figure 4-3, whereas Figure 4-9 illustrates a distribution for a higher wind potential. Table 4.5 summarises the corresponding annual wind energy generation (EG_j - GWh) as well as the respective levelized cost of Electricity ($LCOE_{Wind}$).

Table 4.5
Wind Energy Generation and Levelized Cost of Electricity

Wind Potential	***EG_j - GWh***	***$LCOE_{Wind}$ - $/kWh***
Low Wind Potential (Distribution of Figure 4-8)	56,438	0.34
Medium Wind Potential (Distribution of Figure 4-3)	225,52	0.0875
High Wind Potential (Distribution of Figure 4-9)	393,72	0.05

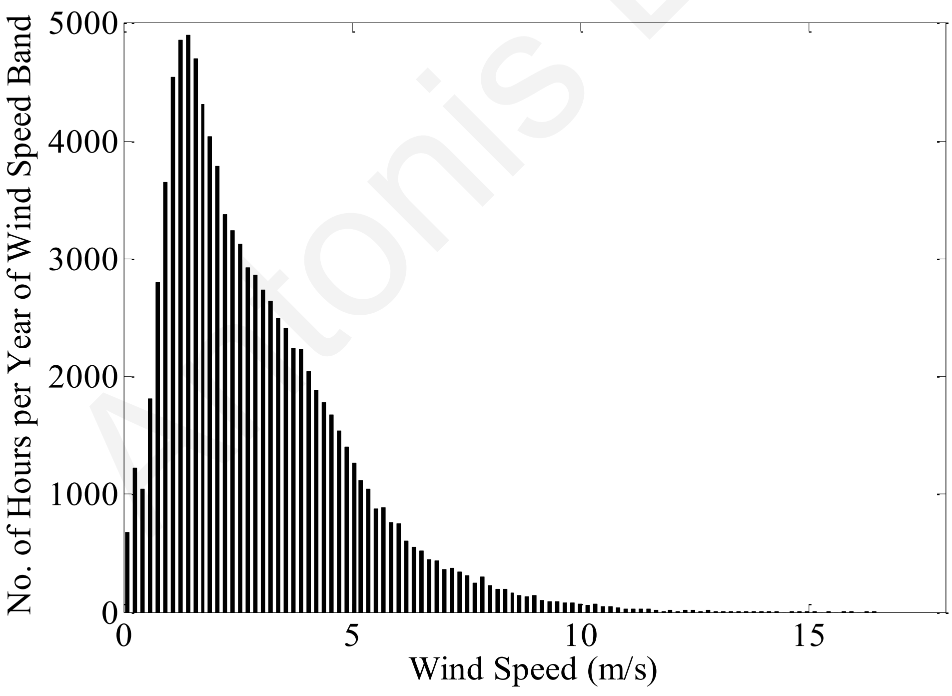


Figure 4-8: Low Annual Wind Potential Frequency Distribution Curve

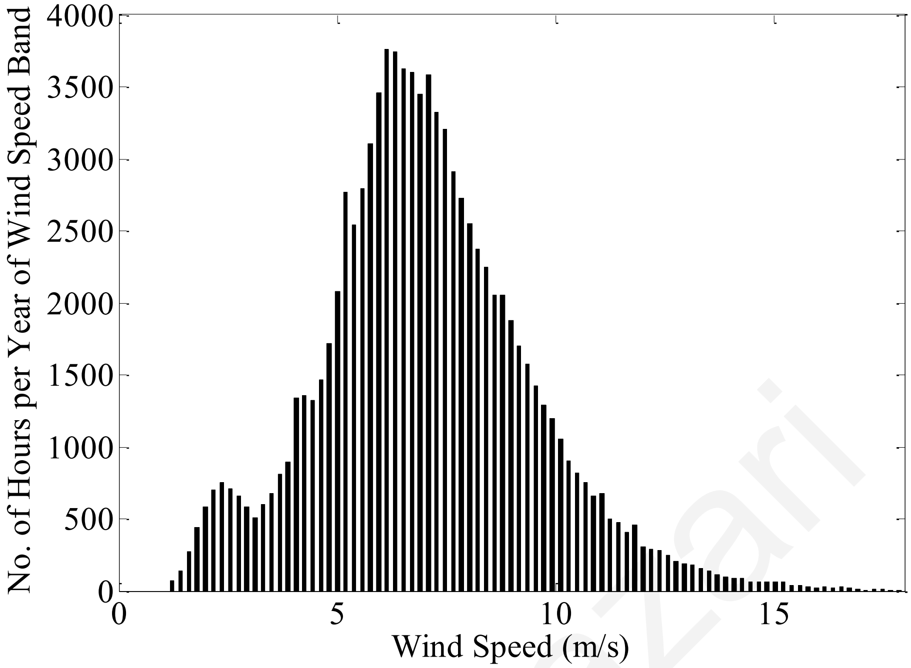


Figure 4-9: High Annual Wind Potential Frequency Distribution Curve

Figure 4-10 illustrates the variation in the transformer's *TOC* distribution for the three different annual wind potentials specified (Figure 4-8: low wind potential, Figure 4-3: medium wind potential, Figure 4-9: high wind potential). The first obvious conclusion is that the higher the wind potential (i.e. higher annual energy yield and thus lower $LCOE_{Wind}$), the lower the median value of the *TOC* distribution of the transformer is. This is expected since the *TOC* of a transformer is dominated by the loss evaluation factors associated with the ONS (i.e. f_{1ONS}, f_{2ONS} and f_{3ONS}) of the wind plant, which are $LCOE_{Wind}$ influenced.

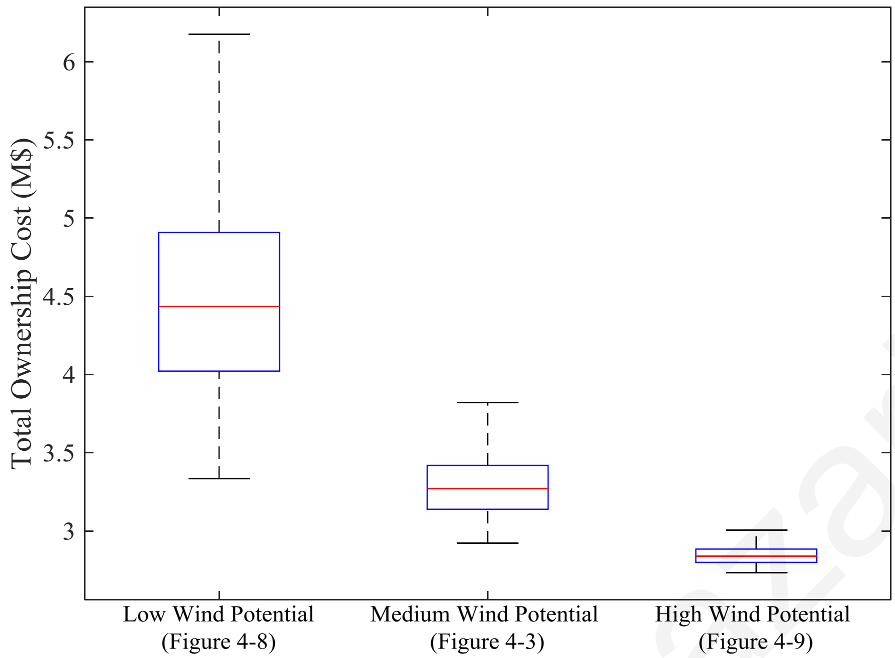


Figure 4-10: Influence of Wind Potential on Transformer Probabilistic *TOC*

However, the sensitivity analysis shows that the resulting *TOC* distribution ($f(TOC;\mu,\sigma^2)$ - *$*) for a low wind potential scenario (Figure 4-8) is more dispersed than in the wind potential cases associated to a Figure 4-3 (medium wind potential) and Figure 4-9 (high wind potential). In fact as the wind potential gets higher the dispersion of the $f(TOC;\mu,\sigma^2)$ values diminishes. This is explained as follows:

- A low wind potential scenario suggests that the probability, at which the wind plant will be on its *STBS*, will be increased. Thus the capitalization of the transformer losses will be more influenced by the *"Market Element"* (i.e.$\left[MP_{STBS}\right]$) rather than the "*Wind Plant Element*" (i.e. $LCOE_{Wind}$). This will force the *TOC* distribution to follow a wider range for the associated market price distribution $f\left(MP_{STBS};\overline{\mu_E},\sigma_E^2\right)$. In contrast, a high annual wind potential scenario, suggests that the wind plant is more likely to be in its *ONS*. Therefore the capitalization of transformer losses will be more confined to the "*Wind Plant Element*" (i.e. $LCOE_{Wind}$) thus making the corresponding $f(TOC;\mu,\sigma^2)$, in Figure 4-10, narrower. Thus, a high wind potential scenario alleviates a significant degree of uncertainty when evaluating the *TOC* of power transformers exclusively serving wind plants.

5

Contemplation of Loss Evaluation Methods for Transformers Serving Large Renewable Energy Plants

5.1 Introduction

5.1.1 General Remarks

This section attempts to constructively benchmark the PV specific and Wind specific, methodologies reported in Chapter 3 and Chapter 4 respectively, over an ABB's online calculator that also attempts to integrate the specifics of renewable energy penetration [47].

5.1.2 ABB Loss Evaluation Method – Renewable Energy

It is noted that ABB has very recently published an online loss evaluation calculator on its website addressing the loss evaluation method under renewable energy penetration [47]. The online calculator refers to power transformers that are obliged to exclusively serve RES sites. The tool provides a method to determine the loss factors of such transformers, by deviating the method's specifics (operational and financial) for Independent Power Producers (*IPP*) and Regulated Utilities (*RU*).

The ABB online calculator in [47] considers the following for the case of *IPP*:

1) The RES plant is able to produce energy only for a fraction of hours in a year; the transformer losses are capitalized according to the plant's Power Purchase Agreement (*PPA - $/kWh*).
2) For the fraction of hours in a year the RES plant is not able to produce energy, the transformer losses are served through a "third-party" source; the transformer losses are capitalized by accounting for the electric rates to be paid to the supplying electric utility (annual Demand (*D - $/kW-yr*) charge rate for purchased power + Energy (*E - $/kWh*))**.**

On the contrary, for the case of *RU* the Power Purchase Agreement concept does not exist as the utility sees the RES plant as just another source of generation. Thus, the total value of the transformer losses is based on:

a) The cost of the additional system capacity needed to cover the transformer losses.

b) The energy cost associated to transformer losses.

c) The annual capacity factor of the RES plant.

5.2 Benchmarking of Existing Methods to the Thesis' Proposed Method

5.2.1 Fundamental Benchmarking

The loss evaluation method for evaluating the TOC of transformers serving RES should take into account two important elements:

a) The inherent generation nature of each renewable source.
b) The type of electricity market associated with the system where the transformer exists in.

All three methodologies reported: a) by ABB [47], b) in Chapter 3 and c) in Chapter 4 partially reflect on the particulars of a RES plant's operating states: 1) the state where the RES plant generates energy and 2) the state where the RES plant does not generate energy (idle). To this end, the transformer losses are then capitalized by appropriately defining the operational and financial characteristics that are respectively applicable for Independent Power Producers (*IPP*) and Regulated Utilities (*RU*). The fundamental difference identified in the three methods is that the method presented by ABB [47] does not distinguish which type of RES plant the transformer is obliged to serve. It also specifically refers to regulated market environments only, as will be further detailed.

However, the methods reported in Chapter 3 and Chapter 4 of this thesis are developed by fully acknowledging that the energy generation profile and characteristics of a PV plant for example, are very different to the specifics of a wind generation application. One should note that the generation profile of a wind farm is extremely volatile and may have multiple ON and OFF states during a day. In addition the methods reported in the 3rd and 4th Chapter of this thesis, respond to liberalized energy markets where the hourly profile of wholesale electricity prices may vary significantly (i.e. they are not fixed).

Table 5.1 tabulates the fundamental comparison (similarities and differences) between ABB online loss evaluation calculator [47] and the proposed loss evaluation methods for transformers explicitly serving large-scale PV (Chapter 3) and Wind (Chapter 4) applications.

Table 5.1
Fundamental Benchmarking of Existing Methods for RES Transformers

ABB TOC Calculator – Renewable Energy [47]	***Proposed Loss Evaluation Methods – Renewable Energy (Chapters 3-4)***
1. Capitalizes transformer losses based on: a) RES plant generates energy b) RES plant does not generate energy (idle)	1. Capitalizes transformer losses based on: a) RES plant generates energy b) RES plant does not generate energy (idle)
2. Applies to Regulated Utilities and Independent Power Producers	2. Applies to Regulated Utilities and Independent Power Producers
3. Applies in regulated energy systems/markets	4. Apply for both regulated and liberalized energy systems/markets
4. Does not distinguish type of RES plant	5. Developed by acknowledging the fundamental characteristics of different RES plants (PV, Wind)
5. RES plant “generating state”: Power Purchase Agreement (*PPA* - *$/kWh*) to evaluate the present value of energy	6. RES plant “generating state”: Levelized Cost of Electricity (*LCOE* - *$/kWh*) to evaluate the present value of energy

5.2.2 Power Purchase Agreement vs. Levelized Cost of Electricity

As noted in Table 5.1, all three approaches (ABB online calculator [47], PV specific method (Chapter 3), and Wind specific method (Chapter 4)) classify the operation of RES plants in one of two different “states”. By virtue of power flow theory and intrinsic nature, during the generating state of RES plants, the power losses of the transformers (serving the RES plants) will be served locally by the RES energy generation. This is a very important remark that could subsequently dictate how the cost of losses (i.e. the present value of the energy *($/kWh*) that will be used by one kilowatt of loss) should be capitalised.

The ABB method reported in [47] approaches the highlighted remark differently from the proposed methods reported in Chapters 3 and 4.The online tool of ABB [47] incorporates the plant’s Power Purchase Agreement (*PPA* - *$/kWh*) to evaluate the present value of energy, whereas the PV and Wind specific methods rely on the renewable energy plant’s specific Levelized Cost of Electricity (*LCOE* - *$/kWh*). The *LCOE* of a RES plant reflects on the direct production cost of the generated energy by capturing the plant’s capital and life-time variable costs. On the other hand, the *PPA* is the price that the RES plant has agreed to sell its generated energy for a long time-horizon. It should be noted that the *PPA* embraces both a revenue margin as well as the credit quality of a renewable generating project throughout the plant’s lifetime. In fact, *PPA* agreements reflect on feed-in-tariff policies (i.e. a long-term contractual basis) and usually apply in regulated energy systems/markets. In liberalised energy markets however, the picture is more complex since feed-in-tariff policies are no longer preferred.

A question is however raised with regard to which of the two elements (i.e. *LCOE* or *PPA*) should be used when capitalizing such transformers' power losses. To respond to this enquiry, the ownership status of the transformer should be clearly defined. Assuming that the transformer owner and the RES plant owner are the same entities, then it may be more appropriate to use the *LCOE* in the evaluation process. This is because it is logical to assume that the losses of the transformer (during the RES plant generating state) will be served locally by the RES plant (rather being accounted from a remote generation service). Thus, the transformer losses should be capitalized according to the transformer's operation and financial perspective in a system.

Starting from the fundamentals (Equation (1-1)), the loss cost rates for transformers' power losses (*NLL* - $f_1(D,E)$, *LL* - $f_2(D,E)$ and *AUX* - $f_3(D,E)$) are appraised to their equivalent Demand (*D* - *\$/kWh*) and Energy (*E* - *\$/kWh*) components of losses. The demand and energy system costs provide the system avoided cost (\$/kW) as well as the true cost needed to supply a kW of demand/loss. Extending the idea, a RES plant has only a demand (i.e. fixed) cost component (i.e. demand component of losses), since a fuel cost (i.e. variable costs) does not exist. With reference to (3-2) and (4-7), the *LCOE* reflects the RES capital and operating expenditure, as well as the available solar/wind potential. It, thus, provides the true cost to generate a kWh of energy, and in extend of the energy needed to supply the RES plant's transformer losses. This pinpoints that the use of the *LCOE* to evaluate for a RES plant's transformer losses (during the RES plant generating state) is more appropriate.

It should be reiterated at this point the *PPA* is the plant's energy price at its delivery point which embraces the cost of generated energy, the plant's cost of losses and a predefined revenue margin. If the *PPA* is used to capitalise the losses, then the corresponding calculated loss factors - to estimate the *TOC* of transformers - will be higher than when the *LCOE* is used.

A transformer owner should thus perform the loss evaluation by accounting only the true cost of the energy needed to supply the losses of the transformers. As previously discussed, in case of transformers serving large renewable energy plants, part of the RES plants' energy will be used to cater for the losses of their serving transformers. This entails that the capitalization of power losses of transformers (during the generating states of RES plants) serving large-scale renewable energy plants can be independent from markets' energy prices or PPA agreements. Therefore, it would be more pragmatic to let their losses capitalization process be dependent on the LCOE of RES generation which is heavily dependent on the RES capital expenditure as well as on the available solar/wind potential in the area the transformer will be installed.

5.2.3 Example – PV Application

The above discussion is hereby supported by some representative examples. A good example would be to consider the case where an Independent Power Producer (*IPP*) is called to decide which transformer is the most cost-effective choice for its PV plant through a tender process, using a loss evaluation methodology. The *IPP* may choose to apply the loss factors calculated using [47] to evaluate the losses of the candidate transformers. Alternative, the loss factors of the PV specific method (Chapter 3) could be utilized. Both scenarios are numerically evaluated by using a set of realistic data and characteristics for a large-scale PV plant. Table 5.2 tabulates the technical and financial specifics of the PV plant considered in this evaluation example.

The annual calculated energy (3-3), using the specifics in Table 5.2, is *191638902kWh*. The PV plant's Levelized Cost of Electricity (*LCOE - $/kWh*) is calculated at *0.1784$/kWh*. The Power Purchase Agreement is assumed to be *PPA=0.23$/kWh*. A further set of data referring to a suitable step-up transformer is given in Table 5.3.

Table 5.2
Technical and Financial Characteristics of PV Plant

PV Plant Capacity (*MWp*)	100
Life – Time Evaluation (years)	30
PV Initial Investment (*IC - M$*)	300
Annuitized Operation & Maintenance Cost (*M$*)	3.9
Annual PV Panels Power Degradation Rate (n_d)	0.50
Total PV Panels Effective Area (A- m^2)	1055600
PV Module Efficiency (n_{ef} - %)	14.70
Annual Solar Potential (kWh/m^2)	1300
Proportion of Hours per year that the PV plant is operated in its Generating State (GS_{FACTOR} - *p.u.*)	0.5064
Proportion of Hours per year that the PV plant is operated in its Non-Generating State (NGS_{FACTOR} - *p.u.*)	0.4936

PV Plant Load/Capacity Factor (LF_{PV} / CF_{PV} - $p.u$)	0.38
PV Plant Loss Load Factor (LLF_{PV} -$p.u$)	0.2222
Inflation Rate (IR_y - %)	1.40
Real Discount Rate (d_r - %)	10

Table 5.3
Transformer Loading and Cooling Characteristics

Transformer Availability Factor (AF – $p.u$)	0.99
Transformer Cooling Operation per year (FOW – $p.u$)	0.30
Initial Transformer Peak Load (Po - $p.u$)	0.80
Levelized Annual Peak Losses of Transformer as per its life-cycle (PQE^2- $p.u$)	0.6452

Table 5.4 tabulates some example values for Commercial/Industrial electricity rates ($CIER_{UT}$ - *\$/kWh)* as well as for Demand (*D* - *\$/kW*) and Energy (*E* - *\$/kWh*) charges that apply for this example.

Table 5.4
Example Values of System Charges

Annual Demand charge rate for purchased power *(D - \$/kW-yr)**	140.30
Energy charge rate for purchased power *(E - \$/kWh)**	0.103
Levelized Commercial or Industrial Electricity Rates charged by Supplying Utility ($CIER_{UT}$ - *\$/kWh)**	0.12
* Assumed Values (Chapter 2 &3)	

Hence, Table 5.5 tabulates the loss factors derived for the methods in [47] and Chapter 3, using the example data in this section. It should be noted at this point that the loss factor ($f_3(D,E)$ - *\$/kW*) attributed to auxiliary losses (*AUX* - *kW*), as this appears in (1-1), is neglected in this example to ensure a consistent comparison. This is because the online calculator of ABB [47] accounts for the capitalized cost of NLL ($f_1(D,E)$ - *\$/kW*) and LL ($f_2(D,E)$ - *\$/kW*) only.

Table 5.5
Benchmarking of Loss Factors (PV)

Loss Factors	ABB Loss Evaluation Method – Renewable Energy [47]	PV Specific Method (3-7)
$f_1(D,E)$ - \$/kW	$f_1(D,E) = (D + E \times 8760 \times NGS_{FACTOR}) + (PPA \times 8760 \times GS_{FACTOR})$ $f_1(D,E)$ = 1605.95 * $f_1(D,E)$ is as calculated in [47]	$f_1(D,E)$ = 1365.58
$f_2(D,E)$ - \$/kW	$f_2(D,E) = PPA \times 8760 \times GS_{FACTOR} \times CF_{PV}$ $f_2(D,E)$ = 387.71 * $f_2(D,E)$ is as calculated in [47]	$f_2(D,E)$ = 113.5

To facilitate a consistent comparison the loss factors shown in Table 5.5 are applied to a set of an example selling prices (*PP - $*) and guaranteed losses (Table 5.6), assuming that these are the bid offers of different transformer manufacturers. In this example all four bids are assumed to represent size-adequate power transformers with comparable features.

Table 5.6
Example of Selling Prices and Guaranteed Losses

Manufacturer	PP (*$*)	NLL (*kW*)	LL (*kW*)
A	1325000	47	290
B	1315000	53	350
C	1305000	61	410
D	1340000	45	200

Therefore Figure 5-1 tabulates the calculated TOC of each of the bid offers described above. The results show that when the loss factors from [47] are applied the offering from manufacturer D is seen to be the most cost-effective. However, when the loss factors of the PV specific method (3-7) are applied then the offering of manufacturer A appears to be the most cost-effective. Moreover, the results verify that when the *PPA* is used to capitalize the transformer losses will lead to higher cost rates which in turn will result in higher transformer TOC.

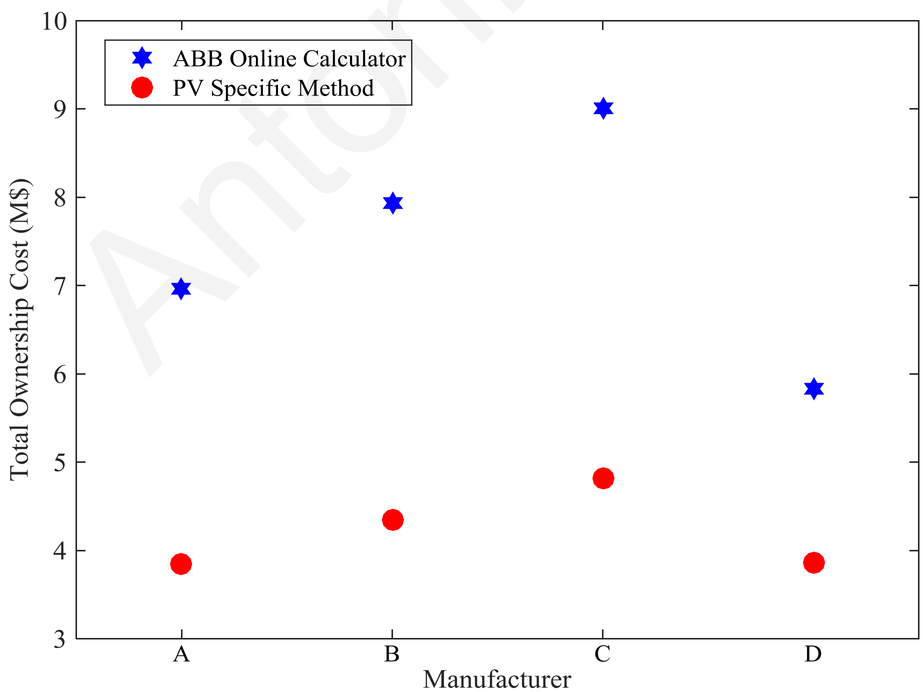


Figure 5-1: Total Ownership Cost of Transformers (PV Plant)

5.2.4 Example – Wind Application

A similar benchmark scenario can be incorporated using the case where an Independent Power Producer (*IPP*) is called to decide which transformer is the most cost-effective choice for its Wind plant through a tender process, using a loss evaluation methodology. As applies for the previous case (PV example), the *IPP* may choose to apply the loss factors calculated using [47] or the Wind specific method (Chapter 4) to evaluate the losses of the candidate transformers. Both scenarios are numerically evaluated by using a set of realistic data and characteristics for a large-scale Wind plant. The example case considered adapts the technical and financial specifics of the Wind plant considered in Section 4.3. The Power Purchase Agreement is assumed to be *PPA=0.15$/kWh*. To this end, Table 5.7 tabulates the loss factors derived for the methods in [47] and Chapter 4, using the example data in Section 4.3. It is reiterated that the loss factor ($f_3(D,E)$ - *$/kW*) attributed to auxiliary losses (*AUX* - *kW*), as this appears in (1-1), is neglected in this example to ensure a consistent comparison.

Table 5.7
Benchmarking of Loss Factors (Wind)

Loss Factors	ABB Loss Evaluation Method – Renewable Energy [47]	Wind Specific Method (4-12)
$f_1(D,E)$ - $/kW	$f_1(D,E) = \left(D \;\; + E \;\; \times 8760 \times P(STBS)\right)$ $+ \left(PPA \times 8760 \times P(ONS)\right)$ $f_1(D,E)$ = 1363.93 $f_1(D,E)$ is as calculated in [47]	*$f_1(D,E)$ = 593.66→1159.45
$f_2(D,E)$ - $/kW	$f_2(D,E) = PPA \times 8760 \times P(ONS) \times LF$ $f_2(D,E)$ = 327.97 *$f_2(D,E)$ is as calculated in [47]	$f_2(D,E)$ = 59.94
***$f_1(D,E)$ is a probability density function according to predicted market prices (4-12)**		

As for the case of PV application, to facilitate a consistent comparison the loss factors shown in Table 5.7 are applied to a set of an example selling prices (*PP* - *$*) and guaranteed losses (Table 5.6), assuming that these are the bid offers of different transformer manufacturers. All four bids are assumed to represent size-adequate power transformers for the specific Wind application with comparable features.

Therefore, Figure 5-2 tabulates the calculated TOC of each of the bid offers that may apply for the example Wind application. Figure 5-2 combines the results for the two methodologies incorporated: a) Single value TOC, result of the online tool in [47], b) A statistical box-plot TOC (following Chapter 4 where the resulting TOC is in the mean of a distribution curve).

To this end, the results show that when the loss factors from ABB [47] are applied the offering from manufacturer D is seen to be the most cost-effective. However, when the loss factors of the Wind specific method (4-12) are applied then the most cost-effective offering depends on the judgment and needs of the transformer owners. The reason is that, since the results are provided by the ease of a statistical box-plot, the appropriate comparison point should be set. To this end, the median value of the statistical box-plot in Figure 5-2 is set as the decision point for the cost-effective choice, when the wind specific method would be used. As a result, manufacturer B appears to be the most cost-effective. Moreover, the results verify that when the *PPA* is used to capitalize the transformer losses will lead to higher cost rates that in turn will result in higher transformer TOC.

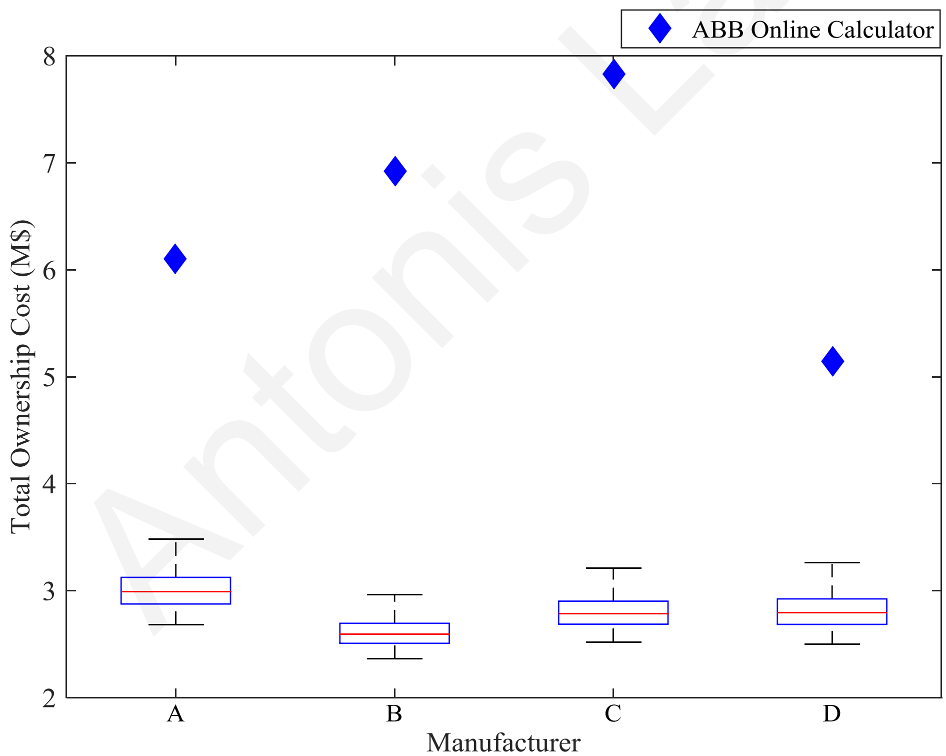


Figure 5-2: Total Ownership Cost of Transformers (Wind Plant)

6

Conclusion

6.1 General Remarks

Significant research and activities are currently underway to investigate the effect of renewable energy penetration, for example in terms of power quality and stability of the system. Nevertheless, this thesis is focusing on a different but equally important element which is the economic evaluation of losses in the new era of Power System operation. This area of research has also a global interest. Thus, the main objective of this thesis is to derive a complete and transparent system approach for evaluating and costing the losses in future networks with increasing penetration of renewable energy systems. This will allow utilities, around the globe, to redefine their ‘’Total Cost of Ownership’’ primarily for transformers and subsequently for transmission feeders and further to congregate the procedure for an economic transformer and transmission feeder change out load when considering Future Networks’ characteristics that include large quantities of renewable energy penetration and competitive/decentralised energy markets. On a global dimension, the proposed methods and approaches described in this thesis, would assist plant’s operators to perform more realistic vendor evaluation. They will also particularly assist transformer manufacturers to develop more efficient designs that they will be popular in the market. There are however, other long-range benefits which would result should the described/proposed methods are materialized, which are more important. It is well accepted, that loss levels are far from optimum in today’s economy, and at all times a reduction in loss levels is desirable. This would inevitably increase the selling prices of the power plant’s equipment. However, through our approaches we aim to reinforce the fact that reducing the losses (by more efficient and expensive units) would mean an overall reduction in the plants total operating and ownership costs. The net effect of such an approach would be firstly to defer the need for utility rate increases and secondly to accomplish significant energy conservation.

6.2 Review of the Work Described

This thesis initially highlights that in the era of low carbon electricity markets and because of the increased penetration of intermittent energy sources (i.e. renewable energy sources – RES), a knowledge gap exists in the transformers’ life cycle loss evaluations. The problems identified are:

a) The existing loss evaluation methods do not exactly appreciate for the discrete characteristics (operational and financial) between differently structured energy systems or utilities.

b) Loss evaluation methods should be accordingly revised for evaluating the ownership cost of transformers operated in a decentralized energy environment.

c) A knowledge gap in transformers' loss evaluation methods relates to transformers that are entitled to exclusively serve large renewable plants (RES).

Initially, Chapter 1 introduces the reader to the field of transformer losses evaluation and techno-economic studies by providing a description as well as a critical evaluation of the existing methods and techniques. In addition, Chapter 1 discusses and highlights the particular needs that have been raised throughout the development of power systems and the actual need to go forward.

Chapter 2 presents a comprehensive model for calculating the cost of the electric power and energy needed to supply the life-cycle losses of power transformers in a vertically-integrated energy system, i.e. the methodology is applicable to power transformer users who possess their own generation and transmission facilities. The proposed concept provides key advancements over any existing methods, so as to provide the flexibility needed to appreciate the diverse operating and financial targets set by each regulated utility in a vertically-integrated system. The proposed method is verified and benchmarked over existing/standardized loss evaluation methods by the means of an example case that incorporates true financial and operating system characteristics.

Chapter 3 offers a complete loss evaluation method to calculate the total ownership cost of power transformers serving large scale solar applications, both in vertically integrated and decentralised energy systems**.** These transformers may be owned by either Independent Photovoltaic Power producers (*IPP*) or by Regulated Utilities (*RU*). In particular, Chapter 3 discusses the arising implications and introduces a method to address these. It is clearly demonstrated that under certain conditions, the Total Ownership Cost (TOC_{IPP} - *$* or TOC_{RU} - *$*) of the transformer serving a PV system can vary based on the method employed. Finally, it is shown that the annual solar potential has an impact on the Levelized Cost of Electricity (*LCOE* - *$/kWh*) and, thus, on the loss factors calculation.

Chapter 4 defines a probabilistic, life-cycle loss evaluation method to evaluate the Total Ownership Cost of power transformers that are obliged to exclusively serve large wind plants. Capitalizing the losses and, consequently, the ownership cost of transformers serving intermittent wind energy sources entails a probabilistic approach that integrates the financial and technical characteristics as well as the uncertainties of wind energy generation. The method introduced, responds to the ongoing efforts of developing risk and cost-based decision making processes in today's competitive and dynamic energy markets. The high level of uncertainties relating to wind energy generation and market characteristics are addressed through a relatively simple and sequential formulation process. The formulation relies on data that most independent power producers retain, by virtue of their business evaluation plans, thus making the application of the proposed loss evaluation method attractive. In addition to the above remarks, Chapter 4 proposes the transformer TOC distribution curve, expressing the correlation of the evaluated TOC to the predicted future market energy prices. As part of the application example presented, Chapter 4 discusses the impact of the available wind potential on the TOC distribution, and more precisely on the level of TOC curve uncertainty.

Finally, Chapter 5 critically contemplates the PV specific and Wind specific, methodologies reported in Chapter 3 and Chapter 4 respectively, over the ABB's online calculator that also attempts to integrate the specifics of renewable energy penetration. It then provides a thorough benchmarking process through the means of a theoretical discussion and application examples for both a large-scale PV application and a large-scale Wind plant. It is extracted that in circumstances where transformers are entitled to explicitly serve RES applications the methodology for assessing the life cycle losses of transformers should be tailored towards the inherent characteristics of each particular renewable source. To this extent it is argued that there cannot be a uniform loss evaluation method for transformers serving all kind of renewable energy sites. This is because the energy generation profile and characteristics of a PV plant for example, are very different to the specifics of a Wind Farm. The main difference that critically influences the loss evaluation method pertains to the generation profile of the specific RES. Moreover, the loss evaluation methods should account for the type of the electricity market associated with the system the transformer exists in. In addition, it is suggested that the loss evaluation process for a transformer serving a RES plant should account only the true cost of the energy needed to supply the losses of the transformers, thus the Levelized Cost of Electricity (*LCOE - $/kWh*).

In conclusion, Table 6.1 gives a brief overview of the loss evaluation methods characteristics before the current work, as well as the contribution of the proposed methods in transformer loss evaluation area. It is, thus, highlighted that a significant contribution has been achieved towards the particular needs of modern power systems.

Table 6.1
Contribution of Developed Models

	Existing Loss Evaluation Methods (Chapter 1.5)	Developed Loss Evaluation Methods (Chapters 2, 3, 4)
Vertically Integrated Energy Systems	✓	✓
Dynamic Energy Markets	✓	✓
Regulated Utilities	✓	✓
Independent Power Producers		✓
Incorporate Fuel Price Predictions		✓
Incorporate System Forecasted Data (Operational)		✓
Incorporate System Historical Data (Financial and Operational)		✓
Renewable Energy Specifics (Wind and PV)		✓
Probabilistic Approach (RES uncertainties)		✓
System Specific Models		✓

6.3 Online Tools

The PV Specific (Chapter 3) and Wind Specific (Chapter 4) transformer loss evaluation methodologies were conveniently transferred into online loss evaluation tools for the interested entities. This was completed after some requests from the equivalent journal papers' reviewers which stated: "Authors are encouraged to develop their Total Ownership Cost calculator according with the methodology of the manuscript in internet (as ABB)". To this end, the online tools developed are as follows:

a) **PV Transformer Loss Evaluation Method (*IPP & RU*): Appendix 1**
The further particulars features and characteristics of this online tool can be found in Appendix 1 – PV Plant's Transformer Evaluation Tool.

b) **Wind Transformer Probabilistic Loss Evaluation Method (*IPP*): Appendix 2**
The further particulars features and characteristics of this online tool can be found in Appendix 2 – Wind Plant's Transformer Evaluation Tool.

6.4 Potential Future Work

While this thesis proposal has described the work performed to enhance loss evaluation techniques towards the era of low carbon electricity markets and renewable energy penetration, there are a number of areas where substantial work and important advancements could still take place. The areas to be studied in relation to transformers' loss evaluation processes are summarized below:

Influence of Rooftop PV Distributed Generation on Distribution Transformers Loss Evaluations

A study should be carried out to study the impact of the increasing penetration of rooftop PV generation in the total ownership cost of distribution transformers. In the light of the forthcoming dis-integration of a number of Power Systems into multiple businesses that will roughly reflect on generation, transmission, distribution and supply categories, the ownership cost of distribution transformers should be re-visited to account for the following:

- How does the load of the distribution transformers changes, when PV energy is generated and consumed locally by retail customers?

- How does the increasing penetration of PV energy at the consumers' end impacts on the cost of losses of distribution transformers (depending on their ownership status)?

- How would the tender-specifications for purchasing new distribution transformers account for the points addressed above?

Online Condition Monitoring of Transformers

An assumption that has been employed, and which is broadly adopted in all loss evaluation endeavours referenced in literature, is that the guaranteed power losses of a transformer (*NLL, LL, AUX*) remain unchanged throughout its complete in-service life. In fact, during the service life of a transformer, several physical phenomena (transformer ageing, thermal stresses, electromagnetic stresses, electro-dynamic stresses) arise that may alter the value figure of its guaranteed power losses. More research could be carried to integrate information provided by transformers' online condition monitoring in loss evaluation endeavours.

Economic Life Expectancy of Transformers (RES Penetration – Wind & PV)

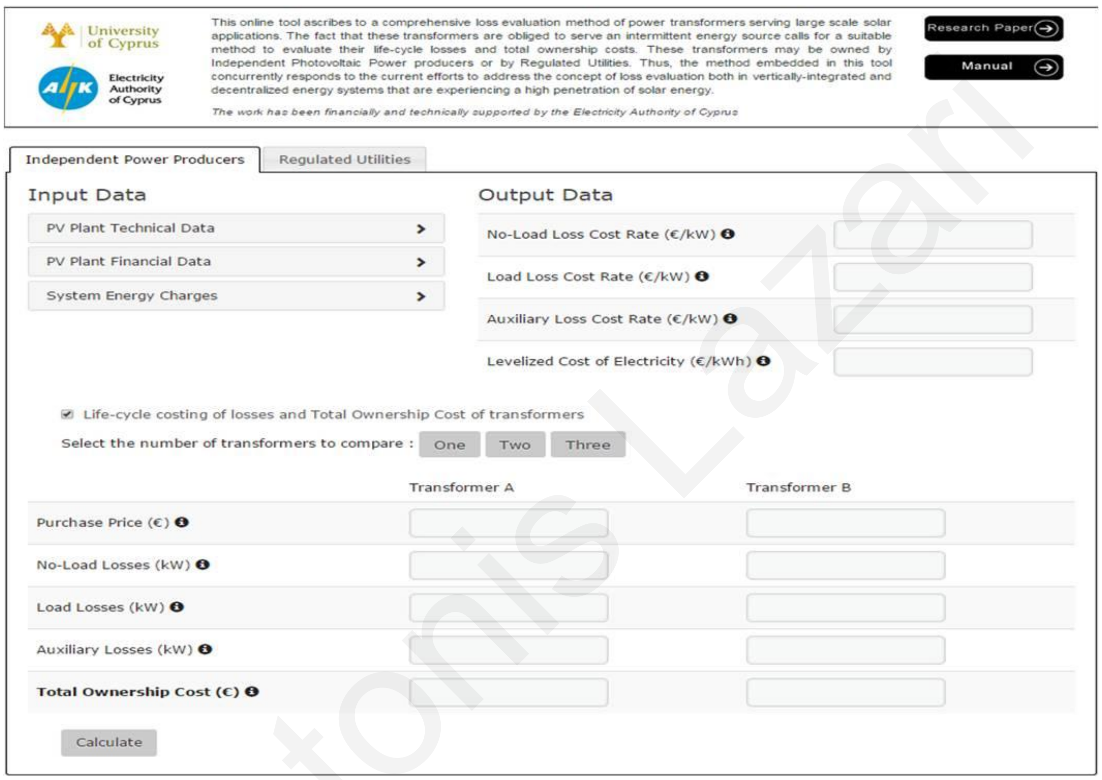
Transformer asset management is generally considered to be one of the most critical management areas with respect to power system equipment. Determining the expected date when transformers will need to be replaced (their retirement date) represents a highly important asset management activity, especially in view of the current aging condition of the overall power system infrastructure. The enormous investment represented by power transformers and the critical role they play in the power grid are further factors that emphasize the importance of the selection of appropriate replacement times. Because this timing involves not only technical issues but also economic factors, decisions must adapt techno-economic feasibility studies. Up to date, the existing transformer loss of life evaluation (or the equivalent transformer replacement evaluation) is related to transformers serving conventional generated energy/load in vertically integrated systems. Following the trends of modern power systems (GHG reduction and increased RES penetration) these studies need to be accordingly revised so as to account for the specifics of a decentralized energy system, or the inherent load profile of a RES generating plant. To this end, the existing methods related to transformers aging can be enhanced to accommodate for the needs and the models developed in this thesis.

Appendix 1

PV Plant's Transformer Evaluation Tool: Guide Memo

PV Plant’s Transformer Evaluation Tool:

http://psm.ucy.ac.cy/loss-evaluation-method-for-power-transformers-serving-large-pv-plants/



Guide Memo

This Memo will guide you through the steps necessary to input a set of data as well as explaining the embedded output options.

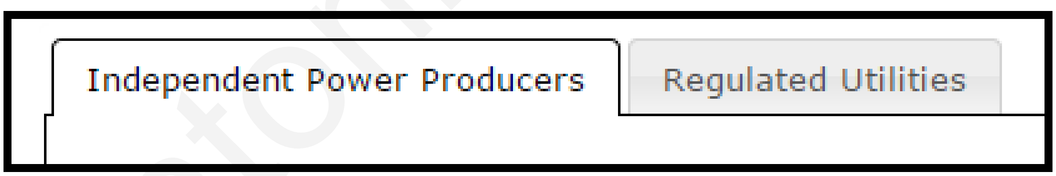
Input Data

Ownership Status

Initially, the correct ownership status of the PV plant should be selected. This is to perform the appropriate loss evaluation process as per the selected option.
The options provided are:

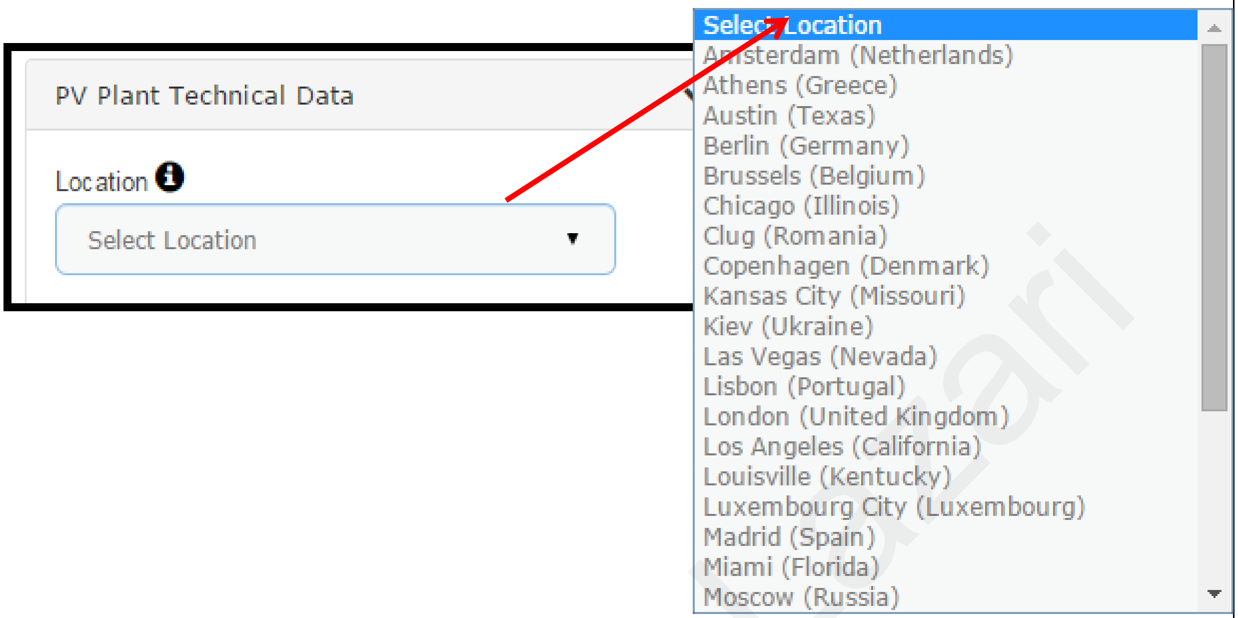
1. ***Independent PV Power Producer***
2. PV Plant is considered as another source of generation in a ***Regulated Utility***

Note: The format of *PV Plant Technical Data* and the *PV Plant Financial Data* is identical for both options. The difference in the two options relies on *System Energy Charges*.

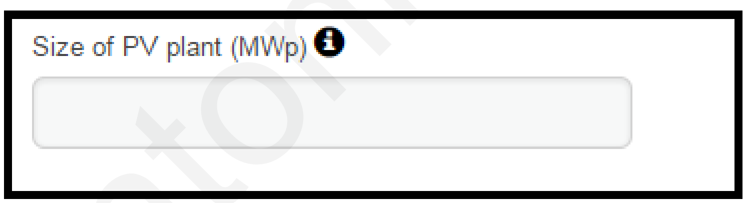


PV Plant Technical Data

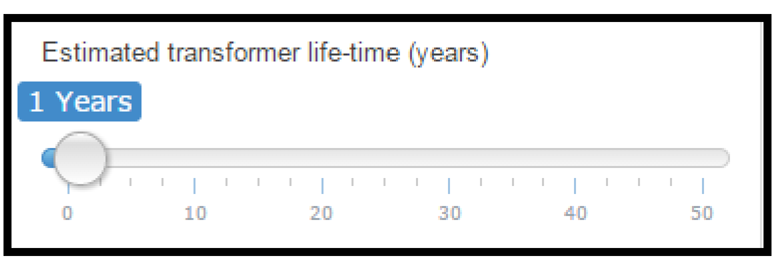
On the ***Location*** option select an area/city. Each area/city is linked to its corresponding Solar Irradiation Profile provided by PV GIS.



For the ***Size of PV Plant*** option insert the peak capacity size of the PV plant in MWp. The size of the plant should be an integer number.

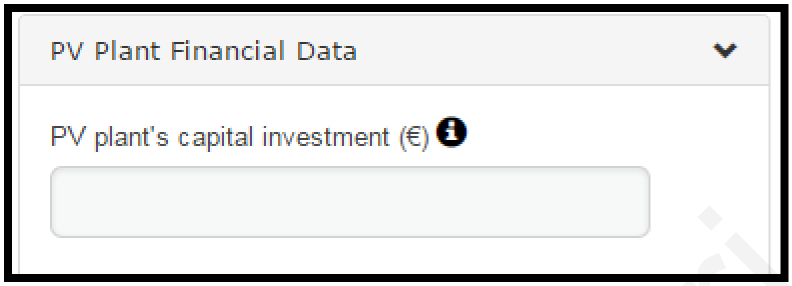


For the ***Estimated Transformer Life-Time*** insert the expected duration of the power transformer operation in years.

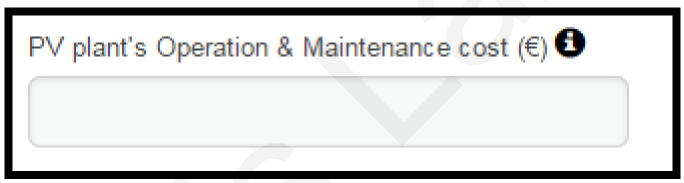


PV Plant Financial Data

On the ***PV Plant’s Capital Investment*** option insert the initial capital expenditure for the PV plant in €.



For the ***PV Plant’s Operation and Maintenance Cost*** option insert the annual expected expenditure for plant’s operation and maintenance in €.



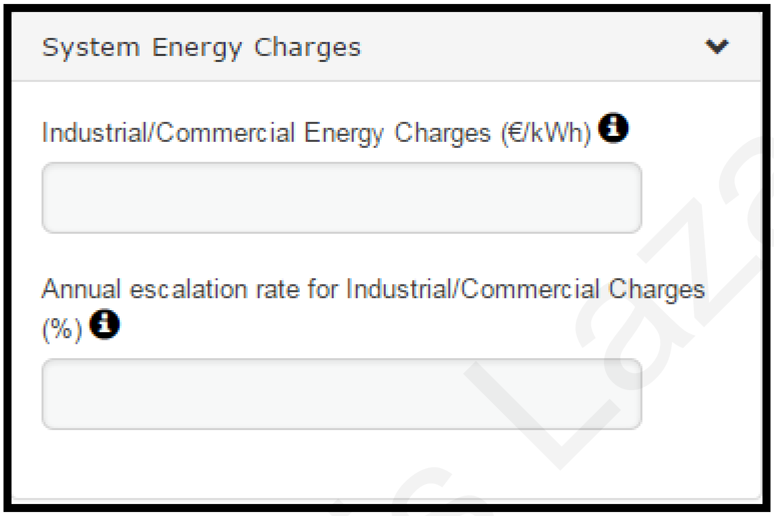
For the ***Nominal Discount Rate*** option choose the interest rate (in %) that will be used in the discounted cash flow (DCF) analysis to determine the present value of future cash flows.
For the ***Inflation Rate*** option choose the annual expected inflation rate (in %) during the evaluation lifetime.

System Energy Charges

Option 1: Independent Power Producers

For the ***Industrial/Commercial Energy Charges*** option insert the average value of the electricity charge rate (demand + energy) that applies in current year (€/kWh).

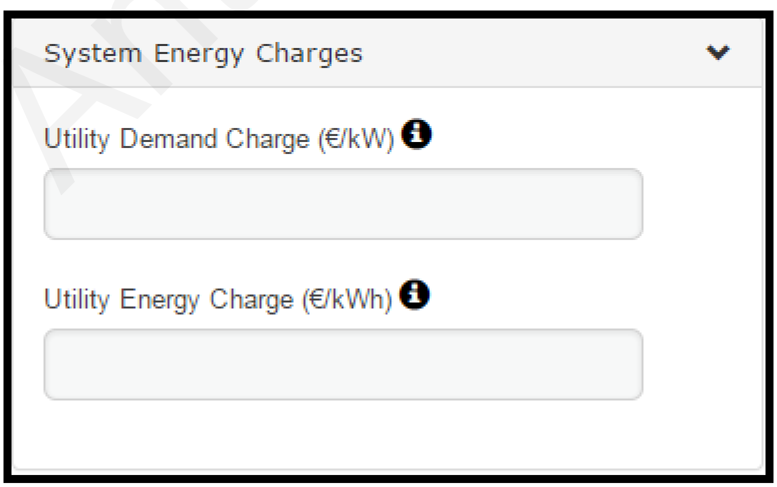
For the ***Annual Escalation Rate of Industrial/Commercial Charges*** option insert the estimated annual escalation rate of Industrial/Commercial charges as a percentage (%).



Option 2: Regulated Utilities

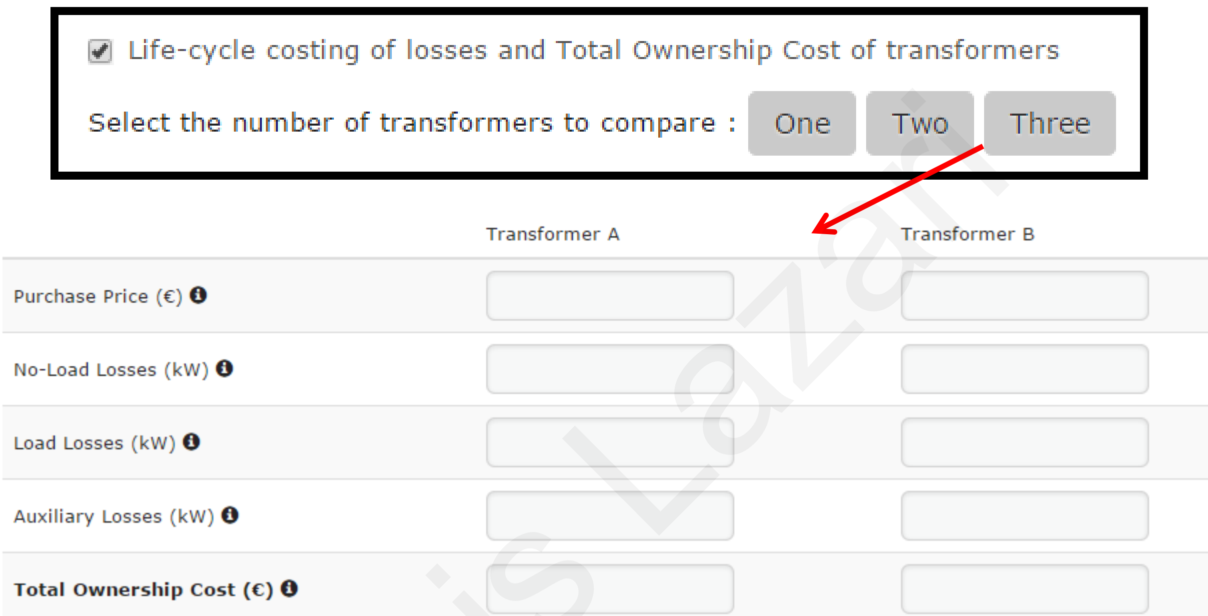
For the ***Utility Demand Charge*** option insert the present utility's specific demand charge (fixed component – capacity dependent) in €/kW.

For the ***Utility Energy Charge*** option insert the present utility's specific energy charge (variable component – energy dependent) in €/kWh.



**Optional:* Transformer Total Ownership Cost

If you wish to calculate the ***Total Ownership Cost (TOC)*** of candidate transformers you should select the displayed option. If this is the case, the required number of transformers to be compared should be selected. The tool provides the ability to compare up to three transformers.



You should then insert the data provided by the manufacturers. The data should be inserted as follows:

For the ***Purchase Price*** option insert the required capital expenditure to buy the transformer in €, as provided by the manufacturer.

For the ***No-Load Losses*** option insert the guaranteed fixed transformer losses due to core energisation, in kW. This is provided by the transformers' manufacturer.

For the ***Load Losses*** option insert the guaranteed variable transformer losses due to the loading of transformer, in kW. This is provided by the transformers' manufacturer.

For the ***Auxiliary Losses*** option insert the guaranteed transformer losses due to power lost by the operation of the transformers' cooling units, in kW. This is provided by the transformers' manufacturer.

The ***Total Ownership Cost*** is an output result, providing the sum of the transformer's purchase price and it's Total Value of Losses (TVL). This figure is expressed in €.

Output Results

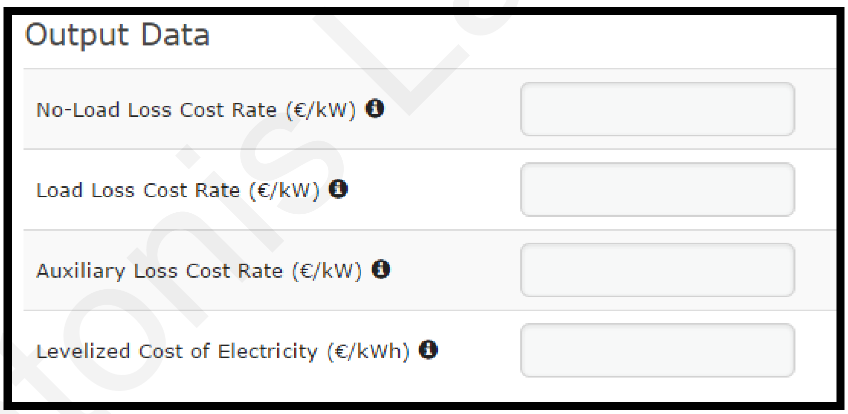
The output results are displayed in a table format. The Table provides the calculated loss cost rates for transformer no-load, load and auxiliary losses. In addition, the PV plant specific Levelized Cost of Electricity of the PV plant is illustrated.

***No-Load Losses Cost Rate (€/kW)*:** Factor that capitalizes or converts no-load loss costs to present value. This is dependent on the industrial/commercial energy prices and the PV plant's Levelized Cost of Electricity

Load Loss Cost Rate (€/kW): Factor that capitalizes or converts load loss costs to present value. This is dependent on the PV plant's Levelized Cost of Electricity.

Auxiliary Loss Cost Rate (€/kW): Factor that capitalizes or converts auxiliary load loss costs to present value. This is dependent on the PV plant's Levelized Cost of Electricity

Levelized Cost of Electricity (€/kWh): It is an economic assessment, in per



kWh cost, to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime.	

For Further Details:

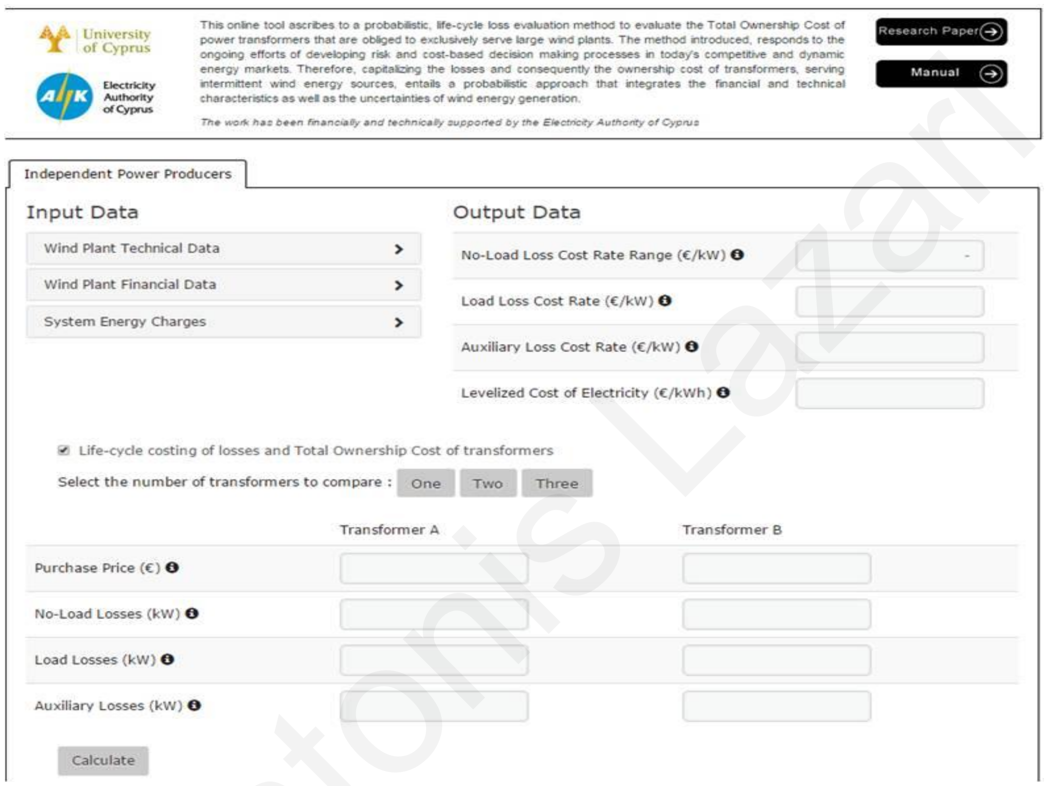
http://digital-library.theiet.org/content/journals/10.1049/iet-gtd.2014.0465

Appendix 2

Wind Plant's Transformer Evaluation Tool: Guide Memo

Wind Plant’s Transformer Evaluation Tool:

http://psm.ucy.ac.cy/probabilistic-loss-evaluation-method-for-transformers-serving-large-wind-plants/



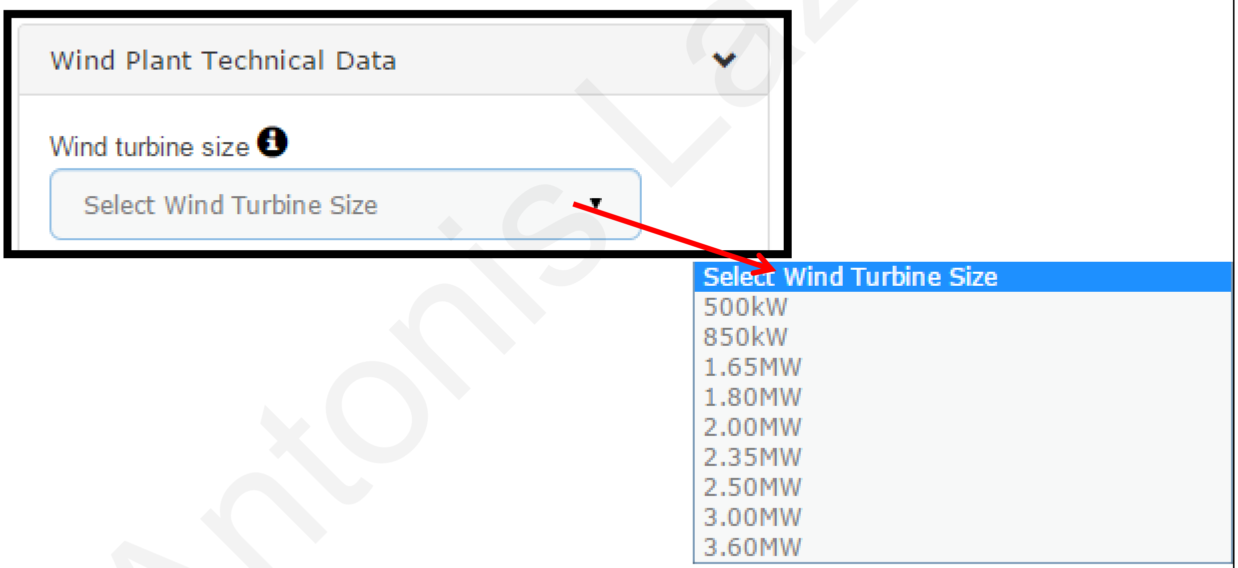
Guide Memo

This Memo will guide you through the steps necessary to input a set of data as well as explaining the embedded output options.

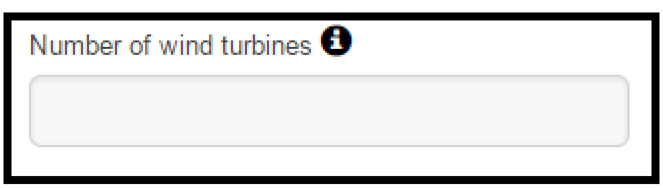
Input Data

Wind Plant Technical Data

On the ***Wind Turbine Size*** option select the rated size of the wind turbines found in a Wind plant. The list provides options for some commercially available wind turbines.

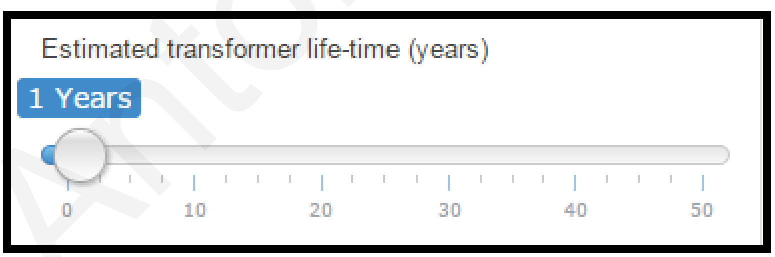


For the ***Number of Wind Turbines*** option insert the number of wind turbines in the plant. The number of wind turbines should only be an integer number.



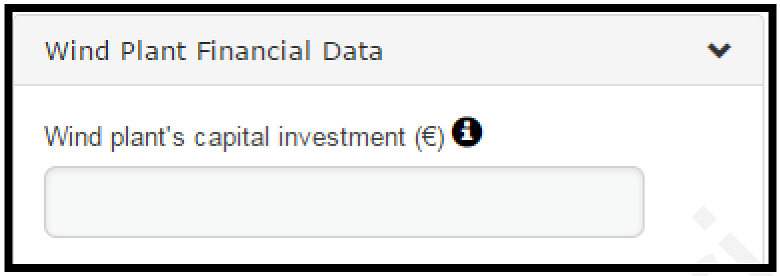
For the ***Wind Potential*** select the wind potential likely to be available plant’s location. (For Example Low = average wind speed ≤2.5m/s, Interim = average wind speed 2.5m ≤*u*≤5m/s, High = average wind speed ≥7m/s).

For the ***Estimated Transformer Life-Time*** insert the expected duration of the power transformer operation in years.

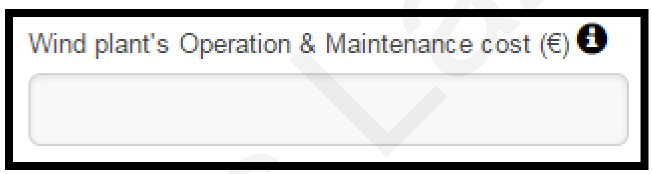


Wind Plant Financial Data

On the ***Wind Plant’s Capital Investment*** option insert the initial capital expenditure for the wind plant in €.



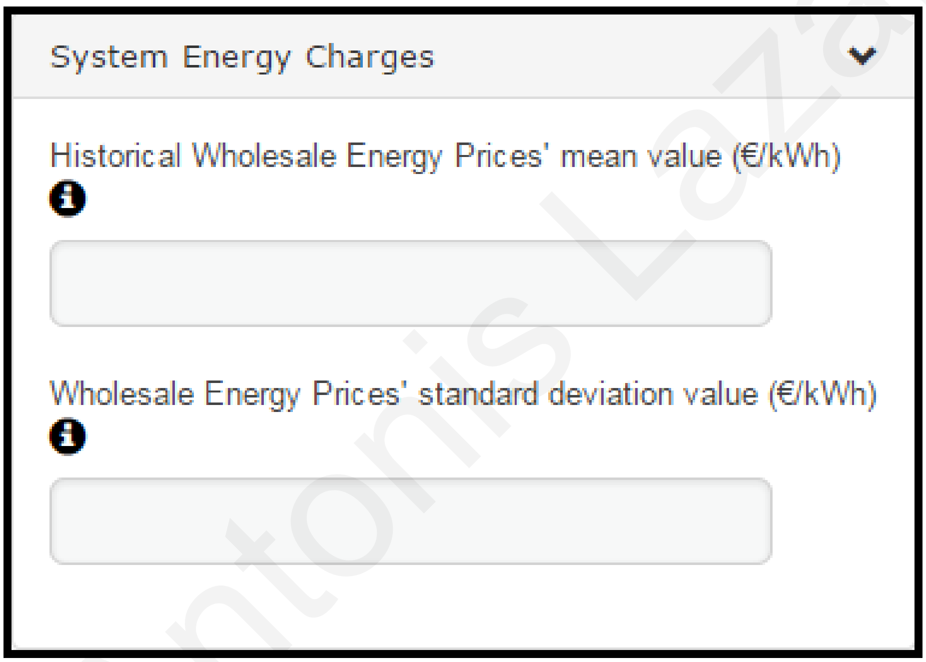
For the ***Wind Plant’s Operation and Maintenance Cost*** option insert the annual expected expenditure for plant’s operation and maintenance in €.



For the ***Nominal Discount Rate*** option choose the interest rate (in %) that will be used in the discounted cash flow (DCF) analysis to determine the present value of future cash flows.
For the ***Inflation Rate*** option choose the annual expected inflation rate (in %) during the evaluation lifetime.

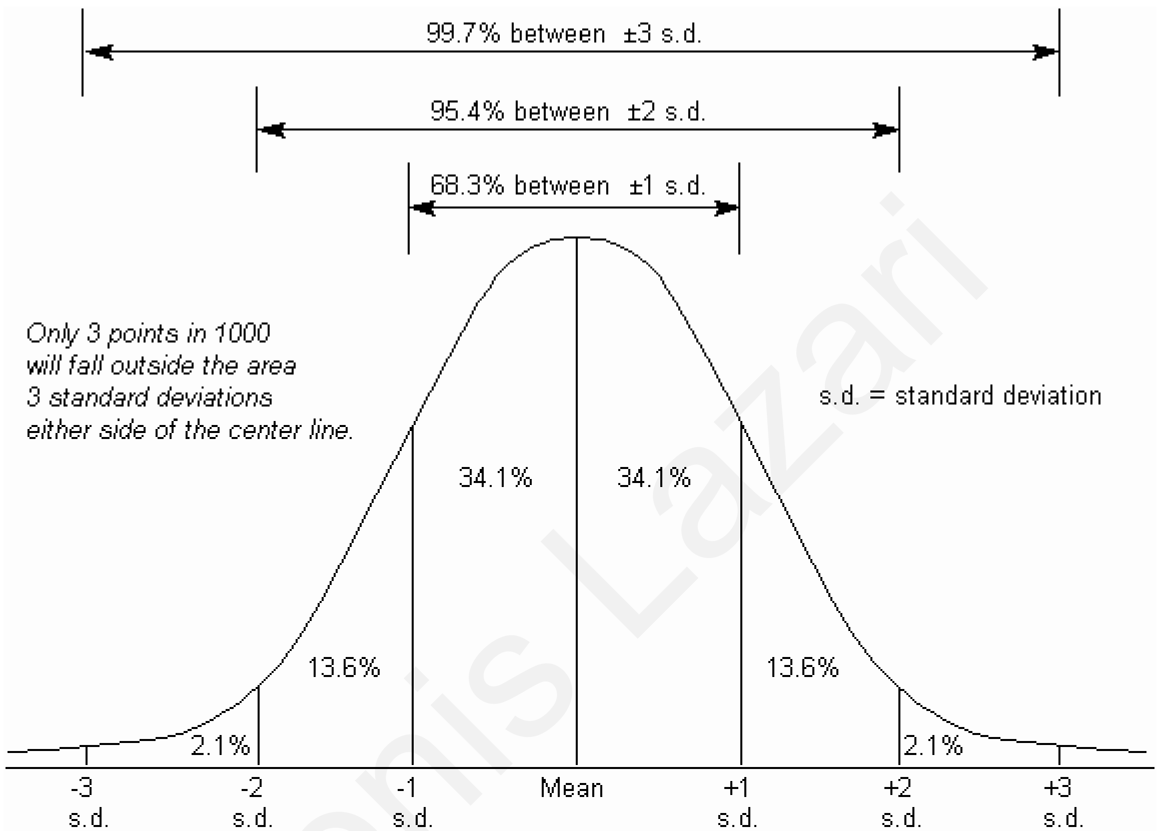
System Energy Charges

For the ***Historical Wholesale Energy Price's Mean Value*** option insert the mean value of the probability density function derived from the available historical wholesale energy prices in €/kWh.
For the ***Historical Wholesale Energy Price's Standard Deviation Value*** option insert the standard deviation of the wholesale energy prices resulting from the statistical treatment of the available historical data of wholesale energy prices in €/kWh.



Example:

The available historical wholesale energy prices may be modeled by a normal distribution as shown:

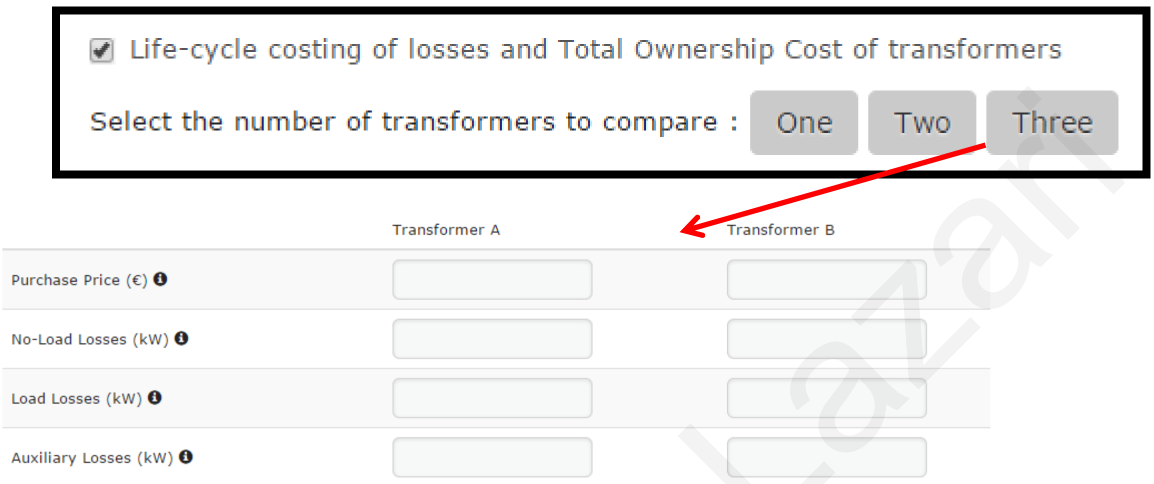


<u>Mean:</u> Mean value of normal distribution
<u>s.d.:</u> Standard Deviation of normal distribution

- ***Historical Wholesale Energy Price's Mean Value:*** Mean Value of the normal distribution shown.
- ***Historical Wholesale Energy Price's Standard Deviation Value:*** s.d. (+1) of the normal distribution shown.

***_Optional:_ Transformer Total Ownership Cost**

If you wish to calculate the ***Total Ownership Cost (TOC)*** of transformers you should select the option displayed. If this is the case, the required number of transformers to be compared should be selected. The tool provides the ability to compare up to three transformers.



You should then insert the data provided by the manufacturer of all the transformers to be compared. The data should be inserted as follows:
For the ***Purchase Price*** option insert the capital expenditure to buy the equivalent transformer in €, as provided by manufacturer.

For the ***No-Load Losses*** option insert the guaranteed fixed transformer losses due to core energisation, in kW. This is provided by transformer's manufacturer.

For the ***Load Losses*** option insert the guaranteed variable transformer losses due to loading of transformer, in kW. This is provided by transformer's manufacturer.

For the ***Auxiliary Losses*** option insert the guaranteed transformer losses due to power lost by the operation of transformer's cooling units, in kW. This is provided by transformer's manufacturer.

Output Results

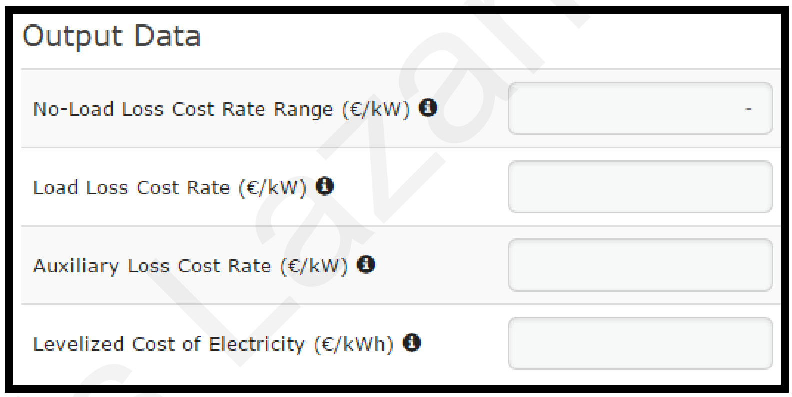
The output results are displayed in a table format and, if the optional transformer Total Ownership Cost check-box is selected, graphically. The Table provides the calculated loss cost rates for transformer no-load, load and auxiliary losses. In addition, the Wind plant specific Levelized Cost of Electricity is illustrated. The graph illustrates the probabilistic **Total Ownership Cost distribution** of the transformers. The distribution is illustrated in terms of a ***statistical box-plot***.

No-Load Losses Cost Rate Range (€/kW)**:** The range at which no-load loss costs are capitalized or converted to present value. This is dependent on the historical wholesale energy prices and the wind plant's Levelized Cost of Electricity

Load Loss Cost Rate (€/kW): Factor that capitalizes or converts load loss costs to present value. This is dependent on the wind plant's Levelized Cost of Electricity.

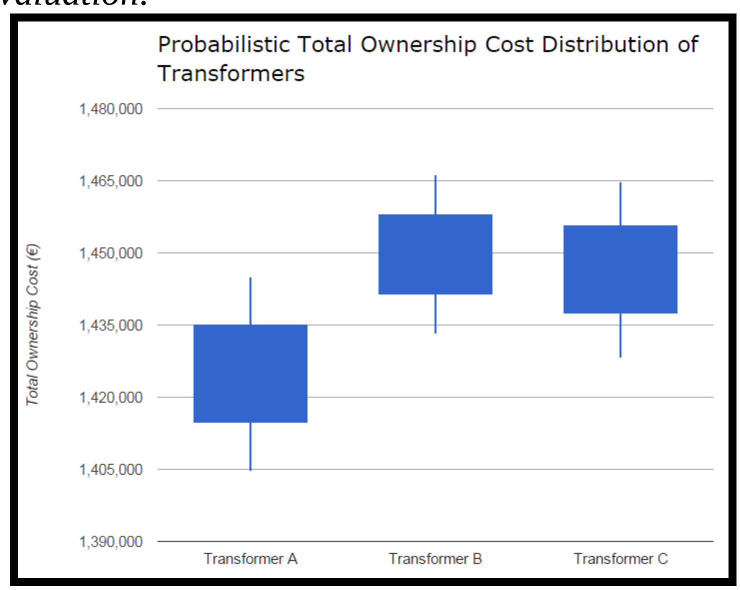
Auxiliary Loss Cost Rate (€/kW): Factor that capitalizes or converts auxiliary load loss costs to present value. This is dependent on the wind plant's Levelized Cost of Electricity.

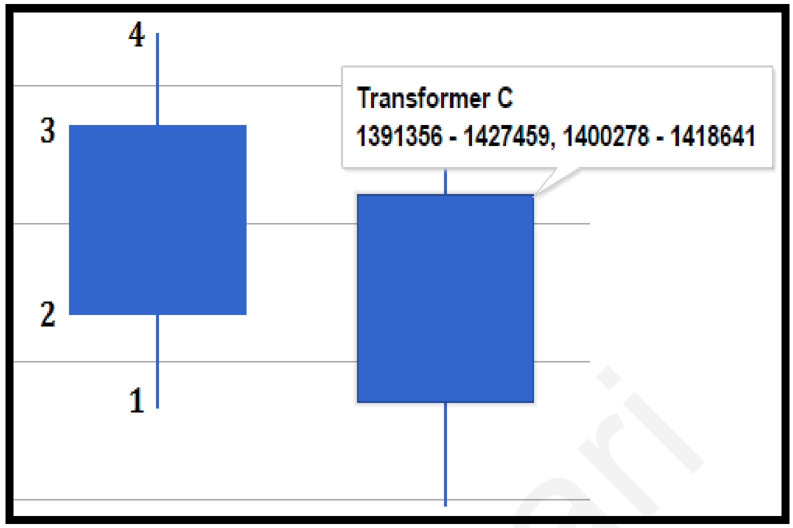
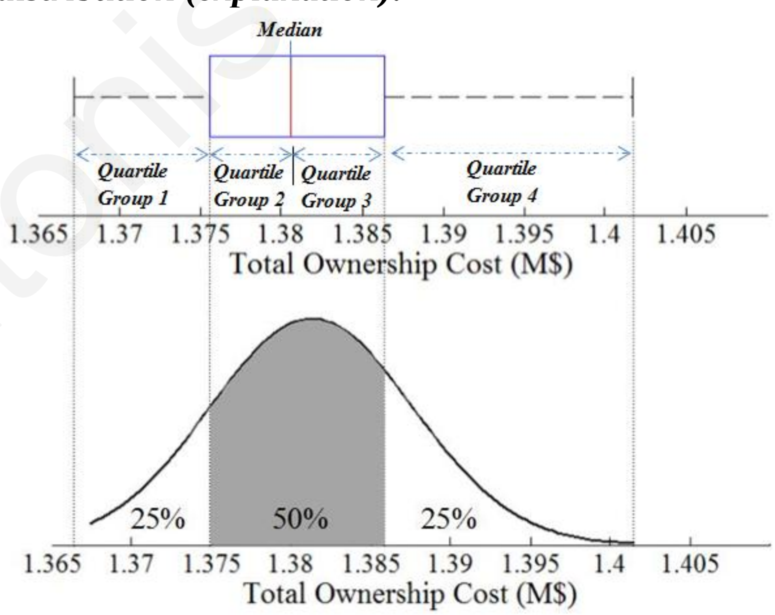
Levelized Cost of Electricity (€/kWh): It is an economic assessment, in per kWh cost, to build and operate a power-generating asset over its lifetime divided by the total power output of the



***Optional:**

Example for three transformers probabilistic TOC evaluation:



asset over that lifetime The graph provides relevant information, for each statistical box plot distribution. The first set of limit provides the range of prices from point 1 to point 4 (see side figure). The second set of limit provides the range of prices from point 2 to point 3 (see side figure).	 **1 – 4:** €1391356 – €1427459 **2 – 3:** €1400278 – €1418641 ***Correlation of a statistical box-plot to normal distribution (explanation):*** 

For Further Details:

http://ieeexplore.ieee.org/xpl/articleDetails.jsp?arnumber=6940295&sortType%3Dasc_p_Sequence%26filter%3DAND(p_Publication_Number%3A61)%26rowsPerPage%3D100

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List of Publications

Peer-Reviewed Journal Papers:

1. Lazari, A.L.; Charalambous, C.A., "Probabilistic Total Ownership Cost of Power Transformers Serving Large-Scale Wind Plants in Liberalized Electricity Markets", *IEEE Transactions on Power Delivery*, vol.PP, no.99, pp.1,1. DOI: 10.1109/TPWRD.2014.2365832.

2. Lazari, Antonis L.; Charalambous, Charalambos A.: 'Life-cycle loss evaluation of power transformers serving large photovoltaic plants in vertically integrated and decentralized systems', IET Generation, Transmission & Distribution, 2015, DOI: 10.1049/iet-gtd.2014.0465IET.

3. Charalambous, C.A.; Milidonis, A.; Lazari, A.; Nikolaidis, A.I., "Loss Evaluation and Total Ownership Cost of Power Transformers—Part I: A Comprehensive Method", *IEEE Transactions on Power Delivery*, vol.28, no.3, pp.1872-1880, July 2013. DOI: 10.1109/TPWRD.2013.2262506.

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6. Lazari, A.L.; Charalambous, C.A., "Contemplation of transformer loss evaluation methods in vertically integrated and decentralized energy systems," in *PowerTech, 2015 IEEE Eindhoven* , vol., no., pp.1-6, June 29 2015-July 2 2015 doi: 10.1109/PTC.2015.7232463

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