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

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***Abstract*—This paper 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 that is 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.**

***Index Terms*—Life-cycle loss evaluation, power transformers, probabilistic total ownership cost, wind energy.**

I. Introduction

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. To this extent, it provides a cost basis for determining the total economic value of the transformer over its estimated life cycle. TOC is typically used to compare the offerings of two or more manufacturers to facilitate the best purchase choice among competing transformers [1]. The approach for estimating the TOC of transformers relies on the concept of life-cycle loss evaluation of transformers. The state of the art of such loss evaluation and TOC methods is reported in [2]–[5]. In particular, loss evaluation is a process that accounts for the sum of the present worth value (PWV) of each kilowatt of loss of power transformers throughout their expected life. The losses of transformers are classified as load losses, no-load losses, and auxiliary losses. Thus, under the process of loss evaluation, each type of transformer loss (no-load, load, auxiliary) is assessed on the basis of the present value (i.e., discounted value) of energy that will be used by each kilowatt of loss during the life cycle of the transformer, in U.S.$/kW. The loss evaluation process subsequently yields the discounted total value of losses (TVL) of transformers over their expected, in-service lifetime. The TOC of a transformer is therefore defined by the purchase price (PP) of the transformer plus its TVL.

To this end, the TOC is considered, by stakeholders, as a decision-making tool and, therefore, its implementation depends on their discretion [3], [4]. There is sufficient evidence in the literature that loss evaluation techniques have been used over the course of the past few decades, for defining the ownership cost including the value of losses of power transformers [6]–[11]. Nevertheless, the majority of these efforts have been concentrated in evaluating the losses of transformers that are a part of vertically integrated utilities. The latter suggests that the generation, transmission, and distribution facilities are owned either by private regulated utilities or by public companies/government agencies. In such vertically integrated systems, the capitalization of power transformer losses (i.e., TVL) accounts for the costs incurred by utilities to produce and transmit each kilowatt of transformer loss over the transformer's lifetime.

However, estimating the TVL of transformers becomes more complex in the context of liberalized electricity markets. To this extent, the classical IEEE standard loss evaluation method [2] refers to vertically integrated utilities only and makes no extensive reference toward evaluating the ownership cost of transformers operated in a decentralized market environment. However, under liberalized electricity markets, several regulated utilities and independent power producers (IPP) coexist. Therefore, the ownership status of transformers, in the context of who is responsible to account for their value of losses, may vary accordingly. To this end, the TVL cannot be simply based on the incurred costs from generation down to the level where transformers are installed, as is the case in vertically integrated utilities. Instead, the capitalization of losses should be based on methods that account for the multiple entities participating in an electricity market as well as the variable energy markets' costs that may be applied during the service operation of the transformers. A step toward addressing a decentralized market-based loss evaluation technique, for evaluating the ownership cost of distribution transformers, is presented in [12].

However, under liberalized energy markets, there is more to investigate. A 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. This constitutes a special case in loss evaluation endeavours. For instance, an independent power producer

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(IPP) who owns a large wind plant should evaluate and subsequently capitalize the losses of its own transformers by taking into account what percentage of these losses that can be covered locally by its produced wind energy. The complication, however, arises from the volatile profile of wind energy generation, since a wind plant may have multiple "ON" and "STAND-BY" states during a day. To this extent, it should be kept in mind that the standard operational practice suggests to maintain wind plants "energized or at hot-stand-by" when the turbines produce no power (i.e., at no load). The same operation concept would therefore apply in the case of transformers which are entitled to serve these plants. This inevitably suggests that these transformers would remain energized and permanently connected to the grid, irrespective of wind activity. This is to allow a bidirectional energy flow between the grid and the wind plant [13].

Consequently, the TVL of these transformers should be evaluated when identifying the proportion in time (e.g., 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.

Toward 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 cases where the wind plant is kept at "hot-standby" (i.e., not generating any power) and, therefore, purchased energy should be used to cover transformer losses.

To address the aforementioned defined challenges, this paper formulates a probabilistic, life-cycle loss evaluation technique to evaluate the total ownership cost of power transformers, owned by IPPs. The transformers are obliged to exclusively serve IPPs' wind plants. The method that is introduced responds to the ongoing efforts of developing risk and cost-based decision-making processes in today's competitive and dynamic energy markets' environments [14]. Therefore, capitalizing on 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.

II. Proposed Methodology

The overall objective of this paper is to appropriately modify the classical TVL formula [1], [2] shown in (1) to account for the special circumstances dictated by wind energy generation specifics in a liberalized market environment. The further particulars of the classical method (1) are tabulated in Table I

$$\mathrm{TVL} = A \times \mathrm{NLL} + B \times \mathrm{LL} + C \times \mathrm{AL}. \tag{1}$$

However, modifying the classical formulation shown in (1) entails understanding and integrating the characteristics of wind energy generation as well as some relevant characteristics of the liberalized energy markets.

TABLE I
NOMENCLATURE

A ($/kW)*	Factor that capitalizes or converts no-load loss costs to present value.
B ($/kW)*	Factor that capitalizes or converts load loss costs to present value.
C ($/kW)*	Factor that capitalizes or converts auxiliary load loss costs to present value.
NLL (kW)	Losses that are generated by the transformer core upon energisation of the unit. These losses are independent of the amount of load that is put on the transformer. Most common types of no load losses include hysteresis (type of core steel) and eddy currents (core construction methods). [2]
LL (kW)	Losses that are generated by the transformer windings and varied by the amount of load present on the transformer. Normally called "I^2R losses" associated with size, length and geometry of the winding construction. [2]
AL (kW)	Auxiliary power lost by the operation of transformers' cooling units. [2]
* Transformer purchasers establish these factors as a means to penalize losses; the higher the design losses, the higher the financial penalty ($).	

The proposed methodology renders the formulation process relatively simple and sequential, by capitalizing on data that wind plant owners/operators definitely retain. Thus, the data used in the probabilistic TOC formulation proposed are no different than the data required to perform a technoeconomic feasibility study for wind plants' operation business. These data include: 1) historical wind speed data; 2) historical wholesale market prices; and 3) technical and financial characteristics of the wind plant including fixed and operating expenditure. The methodology is realized upon following three principle stages (A to C) as follows.

A. Defining Wind Plant Operating States and Loss Evaluation Elements

As discussed in Section I, through a certain time interval (e.g., a day), the wind plant will randomly operate in one of two different states. When operating 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 per the two operating states, namely, ONS and STBS. The two different operating states of a wind plant (ONS and STBS), shown in Fig. 1, will concurrently facilitate the proposed loss evaluation method to rely on two elements. These are defined as: 1) "*wind plant element*" and 2) "*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

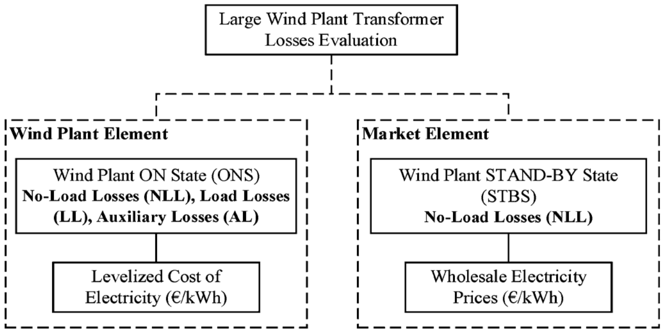

Fig. 1. Outline of the proposed loss evaluation method.

to be on its STBS, the proposed loss evaluation will rely on the financial specifics associated with the "*market*."

In particular, Fig. 1 suggests that the no-load losses (NLL) 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) and the auxiliary losses (AL) may be evaluated under the "*wind plant element*" only. This is because the LL and AL 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 standby 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., on the wind energy-related—levelized cost of electricity—LCOE−U.S.$\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 aforementioned described framework, the classical formulation shown in (1) may be preliminary modified as given in (2). Table II tabulates the further particulars of the nomenclature used in the following equation:

$$\begin{aligned}\mathrm{TVL} = {} & A_{\mathrm{STBS}} \times P(\mathrm{STBS}) \times \mathrm{NLL} + A_{\mathrm{ONS}} \times P(\mathrm{ONS}) \times \mathrm{NLL} \\ & + B_{\mathrm{ONS}} \times P(\mathrm{ONS}) \times \mathrm{LL} + C_{\mathrm{ONS}} \times P(\mathrm{ONS}) \times \mathrm{AL}. \quad (2)\end{aligned}$$

B. Defining Loss Evaluation Factors

The generic formulation shown in (2) contains the loss evaluation factors (A_{STB}, A_{ONS}, B_{ONS}, and C_{ONS}) and the empirical probabilities $P(\mathrm{STBS})$and $P(\mathrm{ONS})$ that statistically define the operation status of the wind plant. Table III associates the evaluation of all terms found in (2) to the "Wind Plant" and "Market" elements, respectively.

1) P(ONS) and P(STBS) Definition: The data required to calculate $P(\mathrm{ONS})$ and $P(\mathrm{STBS})$ rely on historical wind speed data and wind turbines' characteristic power curves. Toward 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 [15]. This empirical

TABLE II
NOMENCLATURE

P(STBS)*	Empirical Probability that defines whether the Wind Plant will be on its STAND-BY State (STBS)
P(ONS)*	Empirical Probability that that defines whether the Wind Plant will be on its ON State (ONS)
***A_{STBS}* (\$/kW)**	Loss Evaluation Factor that capitalizes or converts no-load loss costs, which are attributed to STAND-BY State (STBS), to present value.
***A_{ONS}* (\$/kW)**	Loss Evaluation Factor that capitalizes or converts no-load loss costs, which are attributed to ON State (ONS), to present value.
***B_{ONS}* (\$/kW)**	Loss Evaluation Factor that capitalizes or converts load loss costs which are attributed to ON State (ONS), to present value.
***C_{ONS}* (\$/kW)**	Loss Evaluation Factor that capitalizes or converts auxiliary load loss costs, which are attributed to ON State (ONS), to present value.
**** P(STBS) + P(ONS) = 1***	

TABLE III
TERMS DEFINITION

P(STBS)	"*Market Element*"
P(ONS)	"*Wind Plant Element*"
***A_{STB}* (\$/kW)**	"*Market Element*"
***A_{ONS}* (\$/kW)**	"*Wind Plant Element*"
***B_{ONS}* (\$/kW)**	"*Wind Plant Element*"
***C_{ONS}* (\$/kW)**	"*Wind Plant Element*"

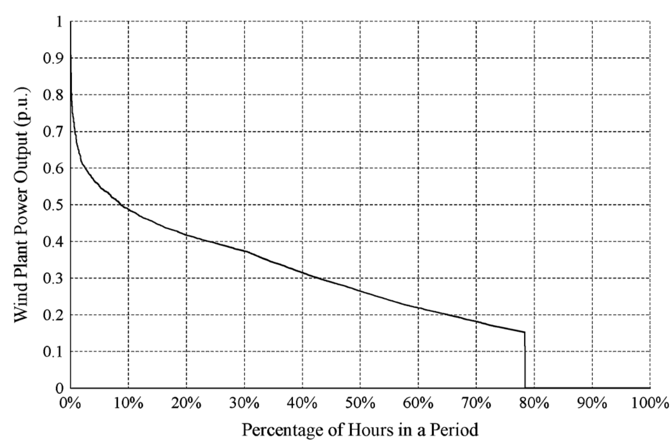

Fig. 2. Historical wind plant power-output duration curve.

historic distribution may be subsequently used as a predictive distribution for the wind plants' future power-output duration curve. By means of an example, Fig. 2 illustrates an empirical annual power-output duration curve, obtained from historical data [16]. It specifically illustrates that the wind plant considered has roughly a 78% probability to be in the ONS—$P(\mathrm{ONS}) \sim 0.78$ and a 22% probability to be in the STBS—$P(\mathrm{STBS}) \sim 0.22$.

2) A_{STBS} Formulation: The A_{STBS} is the loss evaluation factor that capitalizes or converts the no-load loss costs of the transformer to the present value. Since A_{STBS} 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

$$A_{\mathrm{STBS}} = [MP_{\mathrm{STBS}}] \times 8760 \times \mathrm{AF}. \tag{3}$$

Within (3), AF reflects on the availability factor of the transformer, that is, the proportion in time (e.g., 1 year) that the transformer remains energized. $[MP_{\mathrm{STBS}}]$−U.S.$/kWh refers to an array of wholesale energy market prices that are likely to be paid to a supplier, that is, for capitalizing the associated portion of the NLL that falls under the STBS of the wind plant. Therefore, the applied $[MP_{\mathrm{STBS}}]$ should pertain to the energy prices that are reflected in those hours/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 $[MP_{\mathrm{STBS}}]$ array may contain a range of wholesale market electricity charges (U.S.$/kWh). It can therefore take the form of a probability density function—$f(MP_{\mathrm{STBS}}; \overline{\mu_E}, \sigma_E^2)$, resulting from the analysis of historical data. For simplicity, it may be assumed that the same distribution of $[MP_{\mathrm{STBS}}]$ 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

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

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 resulting 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 future year j considered in an evaluation period n. To this extent, the proposed formulation for a levelized probability density function for energy market prices associated with STBS $f(MP_{\mathrm{STBS}}; \overline{\mu_{LE}}, \sigma_E^2)$ is shown

$$\begin{aligned} &f(MP_{\mathrm{STBS}}; \overline{\mu_{\mathrm{LE}}}, \sigma_E^2) \\ &\quad = f\left(MP_{\mathrm{STBS}}; \left[\sum_{j=1}^{n} (\overline{\mu_{Ej}} \times pw_j) \times crf_n\right], \sigma_E^2\right) \end{aligned} \tag{5}$$

where $\overline{\mu_{\mathrm{LE}}}$ 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 [17], and crf_n is the capital recovery factor. A numerical example of the proposed formulation is provided in Section III.

3) A_{ONS} Formulation: Moving further, the A_{ONS} loss evaluation factor should reflect on the "*Wind Plant Element*". The proposed formulation for A_{ONS} is shown

$$A_{\mathrm{ONS}} = \mathrm{LCOE} \times 8760 \times \mathrm{AF}. \tag{6}$$

Within (6), the A_{ONS} formulation embraces the wind energy-related levelized cost of electricity (LCOE−U.S.$/kWh shown) in (7). This is because the LCOE can account for 1) the cost of wind capacity to serve the power used by the losses (while the plant is in its ONS) and 2) the value of the wind energy that will be used by 1 kW of loss during the life cycle of the plant under study

$$\mathrm{LCOE} = \frac{\mathrm{IC}}{\sum_{j=1}^{n} \mathrm{EG}_j \times pwf_j} + \frac{\sum_{j=1}^{n} \mathrm{OM}_j \times pwf_j}{\sum_{j=1}^{n} \mathrm{EG}_j \times pwf_j}. \tag{7}$$

Within (7), n refers to the life cycle of the wind plant in years, IC is the initial investment cost in U.S.$, OM_j are the annual operation and maintenance costs, and EG_j is the expected wind energy generation for each evaluation year, resulting from the correlation of wind speed data to the wind turbine's power curve [15].

4) B_{ONS} Formulation: The B_{ONS} is the loss evaluation factor that capitalizes or converts the load loss costs of the transformer which are attributed to the ONS to the present value. As previously noted in Table III, the B_{ONS} formulation should be associated with the "*wind plant element*" and, thus, with LCOE, as given

$$B_{\mathrm{ONS}} = \mathrm{LCOE} \times 8760 \times \mathrm{LLF} \times \mathrm{PUL}^2 \tag{8}$$

where LCOE refers to the wind-energy-related LCOE defined in (7), LLF to the wind plant loss load factor and PUL to the peak-per-unit load of the transformer [2]. The LLF is defined as the ratio of the wind plant's average power loss (L_{average}) to the wind plant's peak power loss (L_{peak}) over a given period of time (T) as in (9). In the absence of any measured loss values for $(L(t))$, it may be assumed that the wind plant's losses are proportional to the square of the wind plant's generation load (P_w)

$$\mathrm{LLF} = \frac{L_{\mathrm{average}}}{L_{\mathrm{peak}}} = \frac{\int_0^T L(t)dt}{L_{\mathrm{peak}} \times T} \approx \frac{\int_0^T [P_W(t)]^2\, dt}{(P_{W\_\mathrm{PEAK}})^2 \times T}. \tag{9}$$

The peak-per-unit load of the transformer per its life cycle (PUL) is calculated based on the following two assumptions: 1) the transformer maximum loading (Pt_j) is coincident with the wind plant's maximum power output and 2) the wind plant's power output (P_w) is subject to the wind turbines' power-output characteristics. Thus, PU (p.u.) results from the ratio of the average of the estimated annual peak loads of the transformer throughout its lifetime, divided by the transformer-rated capacity. PUL concurrently accounts for the peak-per-unit losses (PUL^2) as given

$$\mathrm{PUL}^2 = \frac{\sum_{j=1}^{n} Pt_j^2}{n \times P_{\mathrm{rated}}^2}. \tag{10}$$

TABLE IV
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$*)	185
Annuitized O&M Cost – Year 1..10 (*M$*) [18]	1.4
Annuitized O&M Cost – Year 11..30 (*M$*) [18]	2.8
Wind Plant Array Efficiency (n_a)	90%
Annual Inflation Rate (IR_y)	1.40%
Nominal Discount Rate (d_r) [17]	10%
Wind Turbine Output Curve -2MW Vestas	[19]
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

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

5) C_{ONS} Formulation: Finally, the C_{ONS} formulation is given in (11). This formulation is able to capitalize the auxiliary (mainly cooling) load loss costs, which are attributed to the ONS to the present value

$$C_{\text{ONS}} = \text{LCOE} \times 8760 \times \text{FOW} \qquad (11)$$

where LCOE refers to the wind-energy-related LCOE defined in (6), and FOW (p.u.) to the average hours per year that the transformer cooling operates.

C. Probabilistic Total Ownership Cost Evaluation

Using the defined loss evaluation factors (A_{STB}, A_{ONS}, B_{ONS}, and C_{ONS}) and the empirical probabilities $P(\text{STBS})$ and $P(\text{ONS})$, the proposed TVL formulation takes the form of a probability density function (12). This provides a distribution of the power transformer's value of losses $f(\text{TVL}, \mu, \sigma^2)$ over its inservice life

$$\begin{aligned}&\text{TVL} = f(\text{TVL}; \mu, \sigma^2) = \\ &\left[f\left(\text{MP}_{\text{STBS}}; \overline{\mu_{\text{LE}}}, \sigma_E^2\right) \times 8760 \times \text{AF} \times P(\text{STBS})\right] \times \text{NLL}+ \\ &[\text{LCOE} \times 8760 \times \text{AF} \times P(\text{ONS})] \times \text{NLL}+ \\ &\left[\text{LCOE} \times 8760 \times \text{LLF} \times \text{PQE}^2 \times P(\text{ONS})\right] \times \text{LL}+ \\ &[\text{LCOE} \times 8760 \times \text{FOW} \times P(\text{ONS})] \times \text{AL}. \qquad (12)\end{aligned}$$

The TOC of a transformer is therefore defined by the purchase price (PP) of the transformer plus its TVL as given

$$\text{TOC} = PP + f(\text{TVL}; \mu, \sigma^2). \qquad (13)$$

III. Application of Method and Numerical Evaluation

The proposed probabilistic TOC is numerically evaluated by using a set of real operational and financial data. Table IV tabulates the technical and financial specifics of the wind plant considered in this evaluation example.

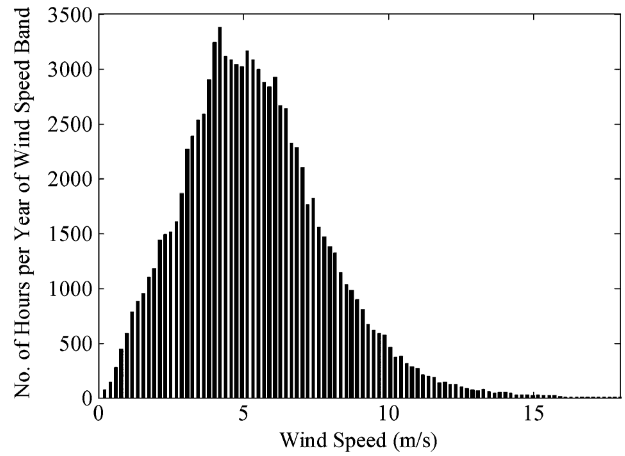

Fig. 3. Wind speed frequency distribution curve.

A. Evaluation of Annual Wind Energy Generation (EG_j)

Fig. 3 illustrates the wind speed frequency distribution curve as obtained from historical wind speed measurements [16]. In particular, the curve results from evaluating 11 years (2003–2013) of wind speed data. It is assumed that the wind speed historic distribution shown in Fig. 3 can be used as the predictive wind speed distribution over the life cycle of the transformers serving the wind plant. To this extent, the expected annual wind energy generation (EG_j) can be estimated by combining the distribution in Fig. 3, to the wind turbines' power curve [19], as per the standard method described in [15]. Thus, under the specifics considered, EG_j will result in 225.52GWh. This value is assumed to constantly apply for each year j of the transformer's life-cycle evaluation.

Moreover, the empirical annual power-output duration curve, as per the same historical data [16] is shown in Fig. 2. As discussed in Section II, the historical analysis provides 78% probability for the wind plant to be in the ONS—$P(\text{ONS}) \sim 0.78$ and a 22% probability to be in the STBS—$P(\text{STBS}) \sim 0.22$.

B. Evaluation of Wholesale Market Prices

The statistical evaluation of the historical wholesale market prices pertains to a set of available data [20]. These data, ranging from 2010–2013, include hourly wholesale energy prices in U.S.$/MWh. This range of wholesale energy prices should subsequently be correlated to historical wind speed (hourly) data over the same four-year period 2010–2013. This correlation is necessary to determine which wholesale energy prices correspond to the STBS of the wind plant (i.e., $[\text{MP}_{\text{STBS}}]$−U.S.$/kWh). Within this example, the STBS is assumed to hold for wind speed values lower than 3 m/s [19]. The process is illustrated in Fig. 4 for a sample of 24-h data.

Thus, by processing the whole set of data, ranging from 2010–2013, following the principles shown in Fig. 4, a probability density function (pdf) of the wholesale energy prices corresponding to STBS, can be deduced. Fig. 5, in particular, shows the pdf $f(\text{MP}_{\text{STBS}}; \overline{\mu_E}, \sigma_E^2)$, resulting from the data processing used in this example. The pdf of Fig. 5 can then be used to describe the distribution of future energy prices. Following the principles described in Section II-B-2 and the

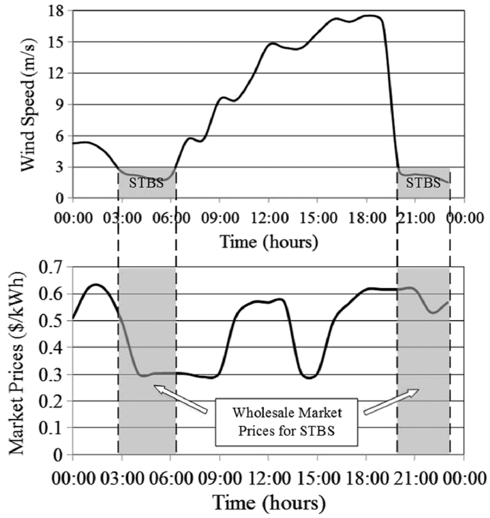

Fig. 4. Correlation of STBS of the wind plant to wholesale energy prices.

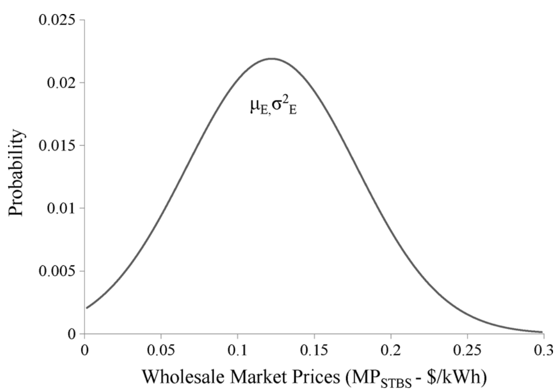

Fig. 5. PDF of historical $\mathrm{MP_{STBS}}$.

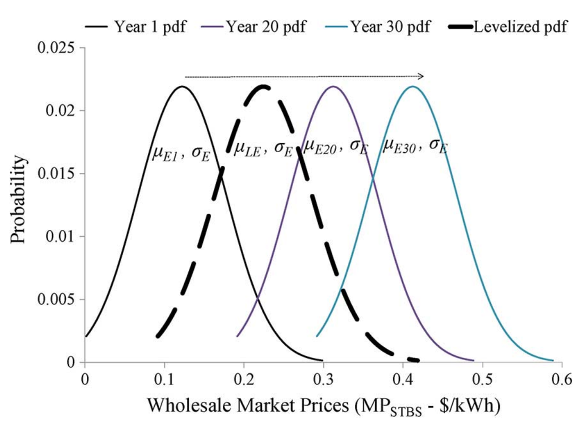

Fig. 6. PDFs of future $\mathrm{MP_{STBS}}$.

formulation given in (4), a pdf for each subsequent year considered in the analysis is obtained. For clarity, Fig. 6 shows the pdfs for a sample of future years (1st, 20th, and 30th). Thus, for each subsequent year in the 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%.

TABLE V
TRANSFORMER LOADING AND COOLING CHARACTERISTICS

Transformer Estimated Purchase Price ($)	1305000
Transformer Guaranteed No- Load Losses (*kW*)	61
Transformer Guaranteed Load Losses (*kW*)	410
Transformer Guaranteed Auxiliary Load Losses (*kW*)	12
Transformer Availability Factor (*AF – p.u*) [2]	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

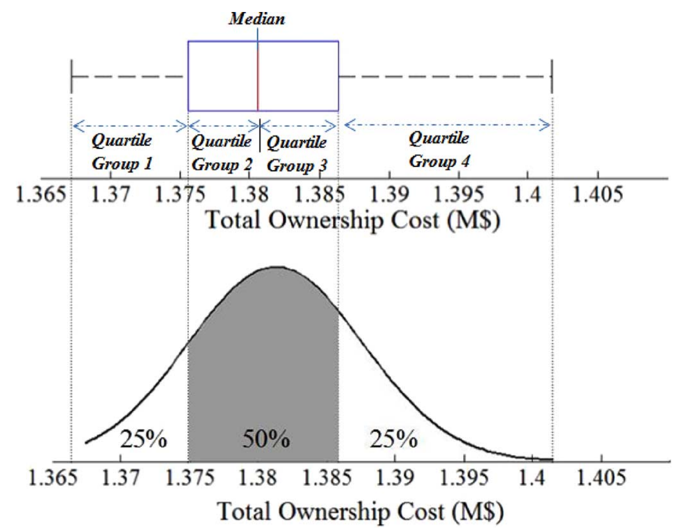

Fig. 7. Total ownership cost distribution.

Using the formulation shown in (5), the levelized pdf $f(\mathrm{MP_{STBS}}; \overline{\mu_{\mathrm{LE}}}, \sigma_E^2)$ can be calculated. This is also marked in Fig. 6.

C. Power Transformer Specifics

Table V tabulates the operational specifics of a power transformer serving the wind plant's specifics (see Table IV) [21].

D. Probabilistic Total Ownership Cost Distribution

Fig. 7 illustrates the total ownership cost distribution for the transformer's characteristics (Table V) by numerically evaluating (12) and (13). The TOC is illustrated in the form of a statistical boxplot [22] combined with its equivalent pdf. Statistical boxplots provide the distributional characteristics of a group of values as well as the level of these values. Thus, Fig. 7 shows the distribution of TOC values. It clearly illustrates the uncertainties resulting from wind energy generation and wholesale market prices variation.

In particular, the TOC distribution is associated with quartiles groups: 1) quartile group 1; TOC ranging from $U.S.1.368M to U.S.$1.3705M; 2) quartile group 2; TOC ranging from U.S. $1.3705M to $U.S.1.3805M; 3) quartile group 3; TOC ranging from U.S.$1.3805M to U.S.$1.386M; and 4) quartile group 4; TOC ranging from $U.S.1.386M to $U.S.1.402M. Each quartile group has a 25% mass probability to occur. It is noted that narrower quartile groups entail higher probability, for the values they embrace to occur. Thus, the TOC values ranging either in 2nd and/or 3rd quartiles distillate a higher probability to occur rather than those TOC values in the 1st and 4th quartiles. This

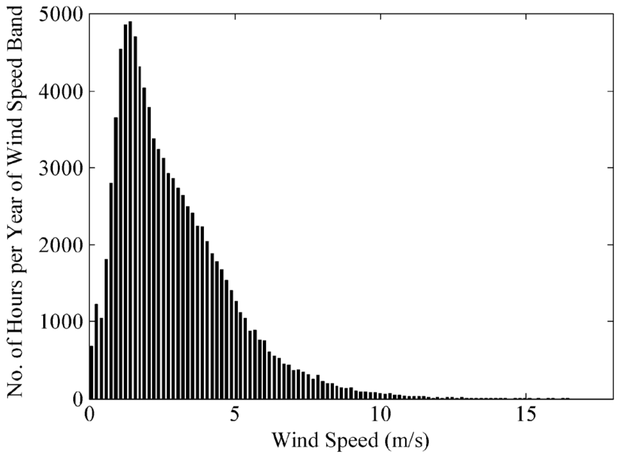

Fig. 8. Low annual wind potential frequency distribution curve.

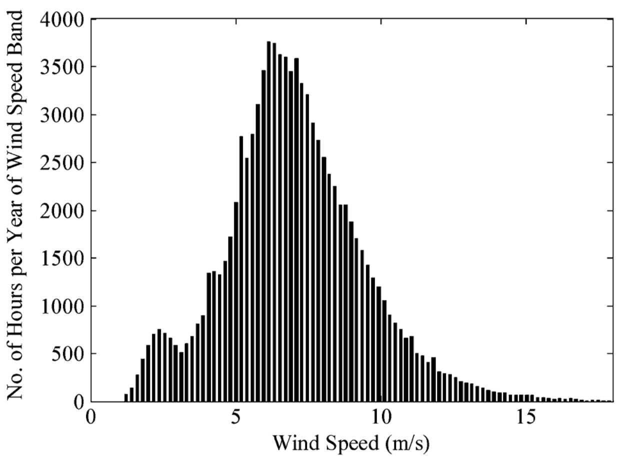

Fig. 9. High annual wind potential frequency distribution curve.

is also evident by inspecting the individual width of each quartile group. The median value shown (U.S.$1.3806M) is related 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.

IV. Sensitivity Analysis

A key factor in the loss evaluation method proposed in this paper is the wind potential (at the location of the plant/transformer) which subsequently determines: 1) (LCOE−U.S.$/kWh) and 2) the ONS and STBS of the wind plant. To address this influence, sensitivity analysis is performed to illustrate the variation in the transformer's TOC distribution for a sample of annual wind potential profiles. To facilitate a valid comparison, the subsequent sensitivity analysis relies on the same technical and financial specifics shown in Tables IV and V, albeit using different annual wind potential frequency distribution curves. To this end, Fig. 8 shows a frequency distribution curve pertaining to a wind potential lower than that of Fig. 3, whereas Fig. 9 illustrates a distribution for a higher wind potential. Table VI summarizes the corresponding

TABLE VI
Wind Energy Generation and Levelized Cost of Electricity

Wind Potential	Annual Wind Generation (EG_j)	Levelized Cost of Electricity (*LCOE*)
Distribution of Fig.3	225.52 GWh	0.0875 \$/kWh
Distribution of Fig. 8	56.438GWh	0.34 \$/kWh
Distribution of Fig. 9	393.72 GWh	0.05 \$/kWh

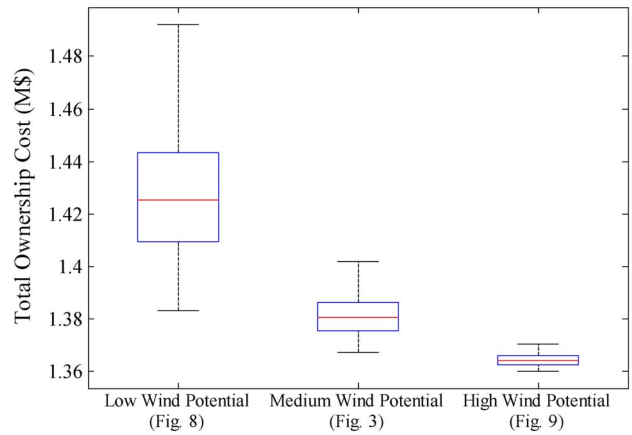

Fig. 10. Influence of wind potential on transformer probabilistic TOC.

annual wind energy generation (EG_j) as well as the respective levelized cost of electricity (LCOE).

Fig. 10 illustrates the variation in the transformer's TOC distribution for the three different annual wind potentials specified (Fig. 8: low wind potential; Fig. 3: medium wind potential; Fig. 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), the lower the median value of the TOC distribution of the transformer. This is expected since at a high wind potential scenario, the TOC of the transformer is more dominated by the loss evaluation factors associated with the ONS (i.e., A_{ONS}, B_{ONS}, and C_{ONS}) of the wind plant, which are LCOE influenced (i.e., "*wind plant element*").

Moreover, the sensitivity analysis (Fig. 10) shows that the resulting quartiles of the TOC distribution for a low wind potential scenario (Fig. 8) are more dispersed than in the wind potential cases associated with Fig. 3 (medium wind potential) and Fig. 9 (high wind potential). In fact, as the wind potential gets higher, the dispersion between the quartiles of the TOC values diminishes. This is explained as follows. A low wind potential scenario suggests that the probability, at which the wind plant is on its STBS, will be increased. Thus, the capitalization of TVL and TOC will be more influenced by the "*market element*" (i.e., $[\mathrm{MP}_{\mathrm{STBS}}]$) rather than the "*wind plant element*" (i.e., LCOE). This will force the TOC distribution to follow a wider range since the associated energy price distribution $f(\mathrm{MP}_{\mathrm{STBS}}; \overline{\mu_E}, \sigma_E^2)$ will also be broader. 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), thus making the corresponding TOC distribution in Fig. 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.

V. Conclusion

This paper defines a probabilistic, life-cycle loss evaluation method for power transformers obliged to serve as an intermittent energy source with varying operational and financial characteristics. Going beyond the classical loss evaluation methods applied in vertically integrated utilities, the proposed method details exactly how transformers' losses should be evaluated, bearing in mind that: 1) the independent ownership status of such transformers; 2) the electricity markets they interact with; and 3) the uncertainties of wind energy generation. The associated formulation process renders itself relatively simple and sequential. 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. An important conclusion highlighted in this paper rests with the immense influence of the wind potential on the TOC evaluation of power transformers exclusively serving wind plants.

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