INTEGRATION OF STORAGE AND PV IN THE DSO POWER LOSSES COST ASSESSMENT METHOD FOR LV PLANNING STUDIES

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ABSTRACT

The distribution system operator (DSO) makes investment decisions in the network by computing the capital and operational expenditures (CAPEX and OPEX). The Joule losses, which are integrated into the OPEX, depend on the power flows in the lines at a given time. The method used by the DSO to estimate the cost of the annual Joule losses is empirical and based on an abacus built with two hypotheses: only loads are connected, to a balanced distribution network. These assumptions made sense in balanced medium voltage power systems with little or no local generation. However, at the low voltage level, a strong development of photovoltaic generation and storage devices is expected, notably affecting the Joule losses. Planners therefore need to ensure that the used model is still valid in these new conditions in order to make the most relevant technical choices. This paper proposes an expression to fit the current DSO abacus and then integrate the storage, the PV production and the unbalance of the network.

INTRODUCTION

The presence of photovoltaic generation (PV) and storage at the low voltage (LV) distribution level changes the location of daily power flows and consequently the power losses. The distribution system operator (DSO) estimates the annual cost of Joule losses, C_{losses}, with (1).

$$C_{losses} = C_{1kWpp}(H_{max}) \times Losses_{max} \quad (1)$$

Where:

- $Losses_{max}$: peak Joule losses,
- H_{max}: equivalent number of hours so that the annual energy consumed is equal to $H_{max} \times P_{max}$,
- P_{max}: peak power consumed during the year (kW),
- $C_{1kWpp}(H_{max})$: cost of 1kW peak power losses, empirically defined as a polynomial of degree 2 of H_{max} [1]. It consists of three terms: (a) the cost of investment annuity for conveying a kW to the consumption areas (network assets cost), (b) the cost of the annual energy lost for 1kW of power consumed during peak time and (c) the power subscription cost (neglected here).

Storage and PV generation affect the maximum annual power P_{max} and its duration of use H_{max}. Thus, it could modify their values as well as the expression (1), used to calculate the cost of Joule losses. In addition, this equation considers a hypothesis in which the voltages on the three phases are equal to the nominal voltage at each instant (balanced operation of the network). This hypothesis is acceptable insofar as the voltage drops are low. At the low voltage level, the networks can be unbalanced due to the presence of single-phase loads and having a low expansion (as well as more and more local generation). These imbalances are responsible for the circulation of a current in the neutral, which generates additional Joule losses.

A detailed study is therefore necessary to calculate the extent to which the presence of PV generation, storage and imbalance modifies the current method of calculating Joule losses and therefore may have a potential impact on investment choices in the network.

In the first part of this article, we will analyze the methodology for calculating the cost of one kW of peak loss as a function of H_{max}, $C_{1kWpp}(H_{max})$, by developing a mathematical model linking the different parameters of the network. Then the parameters influenced by storage and PV generation will be identified and modified in order to propose a model adapted to the case where they are connected to the LV network. The equation thus defined will be applied to a simplified case study in order to validate the proposed models.

COST OF INVESTMENT ANNUITY FOR CONVEYING ONE KW TO THE CONSUMPTION AREAS

<u>Traditional balanced case (without PV and storage)</u>

The cost is determined from the average unit cost of the components of the entire distribution network infrastructure (lines, transformers, protection equipment, among others). The estimation of this cost is complex because it depends on the considered networks as well as load curves characterized by different P_{max} and H_{max}. The average cost of investment annuity for conveying one kW to the consumption areas (C_{A1}), expressed in (2), takes into account both the medium voltage (MV) part (C_{A1_MV}, expressed in (3)) and the LV part (C_{A1_LV}, expressed in (4)). C_{A1_MV} (respectively C_{A1_LV}) consists of the sum of the costs of the MV infrastructure normalized by the average maximum power in the MV (respectively LV) network.

$$C_{A1}(H_{\max LV}) = C_{A1\_MV}(H_{\max LV}) + C_{A1\_LV}(H_{\max LV}) \quad (2)$$

$$C_{A1\_MV}(H_{\max LV}) = \frac{CPS \times AI_{40} + (\frac{LLC_{MV}(CLO_{MV} \times L0_{MV} + CUC_{MV} \times UC_{MV})}{NPS} + (CPD \times PS)) \times AI_{30}}{\frac{H_{\max LV\ av} \times \frac{APP}{NPS}}{H_{\max LV}}} \quad (3)$$

$$C_{A1\_LV}(H_{\max LV}) = \frac{((CSS \times SS_{LV}) + \frac{LLC_{LV}(CLO_{LV} \times LO_{LV} + CUC_{LV} \times UC_{LV})}{NDS}) \times AI_{30}}{\frac{H_{\max LV\ av} \times \frac{APP}{NDS}}{H_{\max LV}}} \quad (4)$$

Table I provides the meaning of the variables used in the equations (2) to (4) as well as the values used for France. The cost of the primary substation is multiplied by the annuity corresponding to 40 years of service [2] and the costs of other equipment are multiplied by the annuity corresponding to 30 years of service [3], [4] and [5].

Table I: Average values used to estimate the cost of investment annuity.

Variable	Symbol	Value in France
Average peak power* (GW)	APP	86.51
Number of primary substations	NPS	2247
Number of distribution substations	NDS	769494
Length of MV lines and cables (km)	LLC_{MV}	613000
Proportion of overhead MV lines	LO_{MV}	61%
Proportion of underground MV cables	UC_{MV}	39%
Length of lines and cables of the LV network (km)	LLC_{LV}	692000
Proportion of overhead LV lines	LO_{LV}	69%
Proportion of underground LV cables	UC_{LV}	31%
Average cost of an HV/LV substation (k€)	CPS	1240 [6]
Average cost of one km of overhead MV network (k€)	CLO_{MV}	31 [7]
Average cost of one km of underground MV network (k€)	CUC_{MV}	115 [7]
Average cost of one km of LV network (twisted, k€)	CLO_{LV}	17 [8]
Average cost of one km of underground LV network (k€)	CUC_{LV}	110 [7]
Average cost of a MV/LV substation	CSS	27.5 k€ [6]
Of which HTA share	SS_{MV}	40%
Of which LV share	SS_{LV}	60%
Annuity investment for a lifetime of 30 years**	AI_{30}	0.089
Annuity investment for a lifetime of 40 years	AI_{40}	0.084
Average H_{max} in LV (h)	$H_{\max LV\ av}$	4000
Discount rate	i	8%

* The average peak power is calculated based on the average of the maximum powers of the years 2010 to 2014 in France [9]. As ENEDIS manages 95% of the French distribution networks, the average power we obtained is scaled down, to focus the results on the main French DSO.
** The annuity investment is computed with (5) [10].

$$AI_F = \frac{i \times (1+i)^F}{(1+i)^F - 1} \quad (5)$$

Where:
- AI_F: annuity investment for a lifetime of F years
- F: life duration of the asset.

As the denominators of (3) (respectively (4)) is in fact equal to the MV maximum average power, $P_{\max MV\ av}$, (respectively LV maximum average power, $P_{\max LV\ av}$). Based on [11], (6) is assumed which leads to the expression of the denominator of (3).

$$P_{max} \times H_{max} = P_{\max av} \times H_{\max av} \quad (6)$$

If we note « δ », the expansion coefficient between the MV and LV loads, we have relations (7). Then (6) and (7) lead to the denominator of (4).

$$H_{\max MV\ av} = \frac{H_{\max LV\ av}}{\delta} \quad (7)$$

Presence of PV generation and storage

If the storage is used in order to reduce the peak, then it allows having an additional margin for the hosting capacity of LV network and thus it reduces the cost of annuity investment. PV generation on its side, will cause an increase in the cost of investment annuity in the case where the maximum power is defined by this generation. Thus, two cases can be defined:
- Case 1: the annual peak is defined by the load (i.e. the PV generation is lower than consumption) and therefore only the storage will have an impact on the cost of investment annuity.
- Case 2: the annual peak is defined by the PV generation (which is then higher than consumption) and in this case

the cost of annuity investment is modified upwards by the PV production and then downwards by the storage.

Case 1: annual peak defined by the consumption

In this case, equations (3) and (4) will have their denominators, $D_{(3)}$ and $D_{(4)}$, modified as it follows:

$$D_{(3)} = \frac{H_{\max LV\,av} \times \frac{APP}{NPS}}{H_{\max LV}} \times (1 + \Delta P_{1MV}) \quad (8)$$

$$\text{With } \Delta P_{1MV} = \frac{P'_{1\max MV} - P'_{2\max MV}}{P'_{1\max MV}}$$

$$D_{(4)} = \frac{H_{\max LV\,av} \times \frac{APP}{NDS}}{H_{\max LV}} \times (1 + \Delta P_{1LV}) \quad (9)$$

$$\text{With } \Delta P_{1LV} = \frac{P'_{1\max LV} - P'_{2\max LV}}{P'_{1\max LV}}$$

Where:

- ΔP_{1MV} (respectively ΔP_{1LV}): additional capacity gained over the MV (respectively LV) network with the storage,
- $P'_{1\max MV}$ (respectively $P'_{1\max LV}$): new annual peak in MV (respectively LV) network with the PV generation only.
- $P'_{2\max MV}$ (respectively $P'_{2\max LV}$): new annual peak in MV (respectively LV) network with the PV generation and storage.

Case 2: annual peak defined by the local generation

It is assumed that even though the PV peak generation increase generates power export to the MV level, it does not increase the MV investment but only the LV ones (different consumer nature and expansion effect). Thus, it is considered that $D_{(3)}$ is identical to (8). At the LV level, $D_{(4)}$, expressed in (9), must then incorporate a cost increase due to the power increase caused by the PV generation. ΔP_{1LV} is then modified into (10) and (11).

$$\Delta P_{LV} = \Delta P_{1LV} - \Delta P_{2LV} \quad (10)$$

$$\Delta P_{2LV} = \frac{P'_{1\max LV} - P_{\max LV}}{P_{1\max LV}} \quad (11)$$

COST OF THE ANNUAL ENERGY LOST FOR 1KW OF POWER CONSUMED DURING PEAK TIME

Traditional balanced case (without PV and storage)

The cost of the annual energy lost for 1kW of power consumed during peak time depends directly on wholesale market prices. The cost of buying losses is subject to their volatility (depending on the situation) as well as to the rise in wholesale market prices depending on the year. The DSO prefer to buy some of the losses in advance, and then adjust over time. This protects them against future price increases. All these factors mean that the cost of lost energy presents a great variability. According to the report of the CRE in 2010, the cost of losses varies between 60 and 90 €/MWh [12]. In this paper an average cost of 75 €/MWh is taken. The cost of the annual energy lost for 1kW of power consumed during peak time, C_{EL}, is given by the DSO in (12).

$$C_{EL}(H_{\max}) = \left(a \times H_{\max} + (1-a) \times \frac{H_{\max}^2}{8760}\right) \times C_L \quad (12)$$

Where:

- C_L: cost of one kWh of electricity (75 €/MWh),
- a: form coefficient. For a given operation, it is considered constant for all structures that are downstream of the load curve [11]. The method described in [2] sets this coefficient to an empirical value of 0.105.

Presence of PV generation and storage

In order to evaluate the influence of PV and storage on the cost of the annual energy lost for 1kW of power consumed during peak time, the following procedure is run for each PV rate, τ, varying from x% to y% and three storage rates, β, (τ/2, τ and 2τ).

1.) Measure of "a" directly on the curve of the MV/LV substation after PV and storage insertion.

2.) Computation of the cost of the annual energy lost for 1kW of power consumed during peak time.

3.) Comparison with the cost obtained with the average value of "a" (0.105).

VALIDATION OF THE MODELS

Traditional balanced case (without PV and storage)

Fig.1 shows that C_{1kWpp}, defined by ENEDIS (in green in Fig. 1), and the proposed analytical model (in black in Fig. 1), based on technical and economic mean values of the French distribution network of Table I, are very close (error varying from 2 to 10%). In addition, the abacus of the DSO considers the power subscription cost, not integrated in the proposed model because data were unavailable.

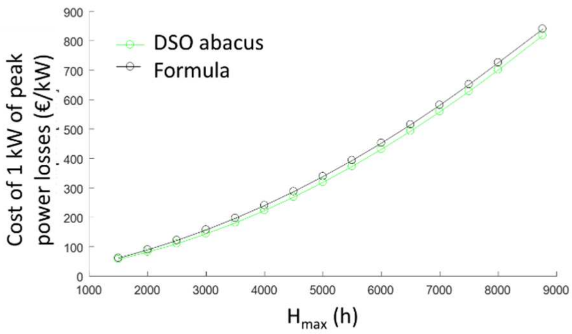

Fig.1: Comparison of $C_{1kWpp}(H_{max})$ abacus and the proposed analytical expression

A sensitivity study was conducted on the variables that could have a significant impact on the calculation of this cost. First, a variation between +/-30% of the average maximum power results in a variation of the cost between 5% and 18%, which is acceptable. A variation of the form coefficient "a" between 0.071 and 0.123, measured on 15000 randomly generated load curves, generates an impact of less than 2% on the cost, which is negligible.

Finally, a variation of the cost of energy between 60 and 90 €/MWh makes the cost of energy lost for 1kW of loss at the peak vary between 8% and 18%. Then considering the mean cost of 65 €/MWh seems to be a good compromise regarding the volatility of this cost. The model proposed the estimation of power losses cost in a traditional case is validated. The proposed modification, representing the presence of PV and storage, are studied in the next section on a simple test case.

Presence of PV generation and storage

A comparative study of the cost of 1kW peak power losses without storage and with PV and storage is performed on the aggregated distribution network of Fig.2.

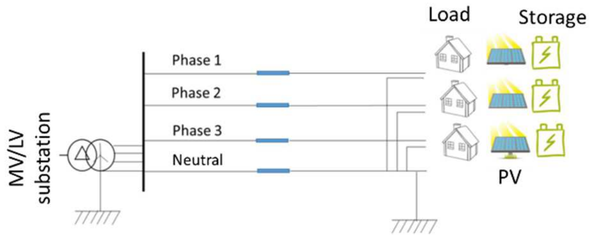

Fig.2: Aggregated test case

This network consists of a distribution station, a three-phase line with a neutral grounded at the substation and regularly along the line and at the consumer, a three-phase balanced load and three-phase PV and storage systems. In this example, the battery is managed with an optimization function, which aims at minimizing the peak power, as shown in Fig.3.

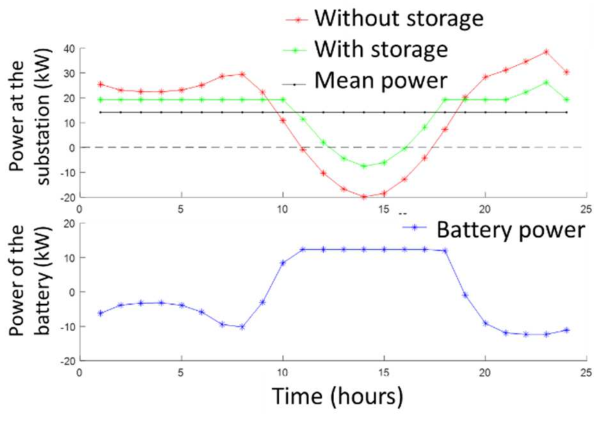

Fig.3: Storage management strategy

The PV rate varies from 5% to 150% with a storage rate equal to the PV level. H'_{max} and P'_{max} values are directly read on the new MV/LV substation power curve and the peak power losses are computed. The cost of losses is then deduced using the ENEDIS abacus (in blue in Fig. 4), and compared to the proposed expression (in red in Fig. 4).

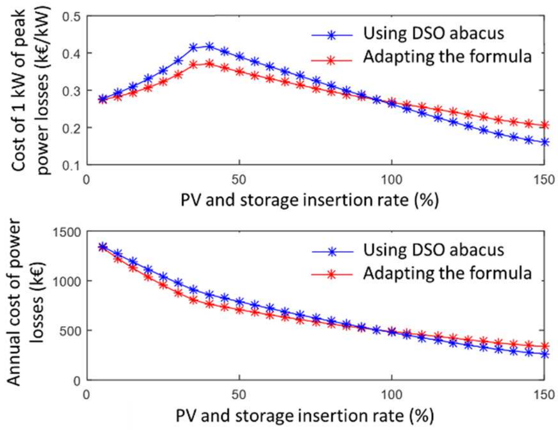

Fig.4. Comparison of losses costs as a function of PV and storage rate (DSO data in blue, proposed model in red).

The difference between the two costs can reach 35%. When the storage penetration remains lower than a given value (80% in this case), the new cost is lower than the DSO one. Above this value, the trend is reversed because the storage effects become limited and the PV production increases the energy cost for a delivered kW (modification of the "a" coefficient). Moreover, in the proposed method, when the PV modifies the H_{max}, the cost of investment annuity is considered constant, if the annual peak is imposed by the consumption, while in the DSO data, the investment cost changes as a function of H_{max}.

IMPACT OF UNBALANCED OPERATION

The unbalance ratio in the neutral, γ_N, is defined in (14).

$$\gamma_N = \frac{1}{1 + \frac{\sum_{t=1}^{8760} \sum_{i=1}^{3} Losses_i(t)}{\sum_{t=1}^{8760} Losses_4(t)}} \quad (14)$$

Where:

- $Losses_i(t)$: Power losses in phase i at time t for i = 1 to 3 and in the neutral for i=4.

The three-phase load of Fig. 2 is represented by three single-phase loads, with a possible imbalance operation. The conductors of the three phases (of length 200m in this paper) have the same section (95 mm² aluminum with a resistance of 0.362 Ω/km and a reactance of 0.777 Ω/km) and the same mutual impedances.

A Monte-Carlo approach is used to estimate the unbalance ratio in the neutral. At each iteration and for each storage rate, an equivalent load curve on each phase of the MV/LV substation is generated. A loadflow is performed on the 8760 time steps of these load curves in order to determine the annual losses in the neutral and in the 3 phases. The imbalance rate, γ_N, is then calculated according to (12). Fig. 5 shows the neutral imbalance rates for different storage rates.

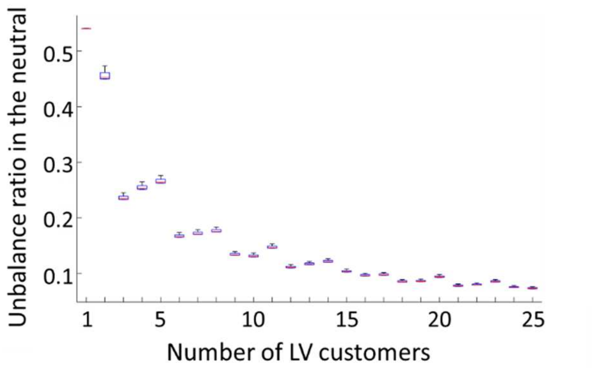

Fig.5. Dispersion of unbalance ratio in the neutral regarding storage rates as a function of the number of LV customers.

The presence of storage does not modify the value of this average imbalance rate (low dispersion for a given number of customers). Indeed, the role of storage here is to smooth the peaks that happen at times during which consumers behave the same way (evening peak), unlike the imbalance principle. It can also be seen that whatever the storage rate value is, the higher the number of customers is and the less imbalance there is. Thus, over 20 customers, losses in the neutral represent less than 10% of total losses. Then, the annual cost of power losses can be updated with (13) to take into account the imbalance of the LV network.

$$C_{losses} = \sum_{i=1}^{3} \frac{C_{losses}(i)}{1-\gamma_{N(cu)}} \quad (13)$$

Where:
- C_{losses} : total cost of the annual lost energy.
- $C_{losses}(i)$: cost of annual energy lost for phase i.
- cu : number of customers.

CONCLUSION

In this article, the authors proposed a formulation of the method used by the DSO to calculate the cost of annual losses and its adaptation to the presence of local PV generation and storage. In LV networks, it is shown that the presence of PV and storage can be not negligible (up to 35% of difference in the case studied).

In addition, the model was extended to the unbalanced case by a simple relationship showing that storage does not affect the imbalance if it was used to reduce the peak. Only the number of consumers affects the cost of losses. However, this impact becomes less than 10% if the number of consumers increases above a certain value (20 in our study).

The method and results presented here can be improved by applying values from other countries, deepening sensitivity studies and modeling the LV network in more detail.

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