Evaluating Distributed Time-Varying Generation Through a Multiobjective Index

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***Abstract*— In the last decade, distributed generation, with its various technologies, has increased its presence in the energy mix presenting distribution networks with challenges in terms of evaluating the technical impacts that require a wide range of network operational effects to be qualified and quantified. The inherent time-varying behavior of demand and distributed generation (particularly when renewable sources are used), need to be taken into account since considering critical scenarios of loading and generation may mask the impacts. One means of dealing with such complexity is through the use of indices that indicate the benefit or otherwise of connections at a given location and for a given horizon. This paper presents a multiobjective performance index for distribution networks with time-varying distributed generation which consider a number of technical issues. The approach has been applied to a medium voltage distribution network considering hourly demand and wind speeds. Results show that this proposal has a better response to the natural behavior of loads and generation than solely considering a single operation scenario.**

***Index Terms*-- Distributed generation, distribution networks, multiobjective analysis, wind power.**

I. Introduction

DISTRIBUTED Generation (DG) presents distribution networks with a significant challenge. Various studies have demonstrated that integration of DG in distribution networks may create technical and safety problems [1]-[4]. Consequently, it is critical to assess the technical impacts of DG in power systems in order to connect generators in a manner that avoids degradation of power quality and reliability. Depending on its location and capacity, DG may increase fault currents, causes voltage variations, interfere in voltage control processes and diminish or increase losses, etc. Increasing penetrations of variable renewable generators, of which wind power is currently the most significant [5], makes it essential to account for the time-varying characteristics of both generation and demand.

Chiradeja and Ramakumar [6] presented a "static" approach aimed at quantifying the benefits of DG such as voltage profile, line-loss reduction and environmental impact reduction. Nonetheless, technical issues that could measure the negative impacts of DG were not included. Wand and Hashem Nehrir [7] proposed an analytical approach for optimizing the allocation of DG, considering the variability of demand and power generation by using daily average curves. Zhu *et al*. [8] introduced the use of time-varying loads for analysis of reliability and efficiency of distribution networks with DG. Seasonal load curves were also used by Greatbanks *et al*. in [9]. Méndez Quezada *et al*. considered in [10] the variability of demand and various DG technologies, aimed at assessing energy losses for different penetration scenarios. In [11], El-Khattam *et al*. took into account, through a deterministic and stochastic analysis, the DG variability along with load curves, aiming the maximum insertion within specific penetration limits. Consequently, the results of purely "static" snapshot approaches using specific loading and generation scenarios, may result in challenges or opportunities being neglected.

In this work, a time-varying approach is applied to both load and generation, and a steady-state analysis of technical issues such as losses, voltages, reserve capacity of conductors and short-circuit levels is presented. This is based on the creation of a multiobjective performance index by relating the different technical issues by assigning weighting factors. Although legislation generally disallows utility-owned generation and/or guarantees open access to those independent energy producers, in practice, distribution engineers are limited in their ability to specify the connection point of a DG unit, the existence of such an index would indicate where DG could be more beneficial for the distribution network and assist distribution engineers in taking technical and economic decisions.

This paper is set out as follows: Section 2 presents the distribution network impact indices to be considered in the methodology and also lays out the multiobjective performance index. Section 3 presents a medium voltage distribution network along with demand and wind speed profiles applicable to the UK. In Section 4 results obtained with the multiobjective performance index are analyzed.

II. Distribution Network Impact Indices and the Multiobjective Performance Index

Technical indices presented in a previous work by the authors [12], aimed to assess impacts for the single scenario of maximum generation and maximum demand. Here, these are

The first author is grateful for the financial support given by FEPISA (Ilha Solteira - SP, Brazil).

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adapted and extended for use with time-varying demand and generation profiles. Phases *a*, *b* and *c* and the neutral wire (*n*) are taken into account to properly describe the inherent load, topology and unbalance of distribution networks, although the approach is equally applicable to balanced systems.

For the *k*-th distribution network configuration with DG the indices considered are:

A. Real and Reactive Power Losses

Depending on the location, demand and generation at a given instant, DG may unload lines and reduce losses or, alternatively may give rise to excessive losses. The first two indices (*ILp* and *ILq*) express, respectively, the real and reactive energy losses for a given horizon. Thus, a beneficial DG location would decrease total network losses, resulting in near-unity values of *ILp* and *ILq* which are defined as:

$$ILp^k = 1 - \frac{\sum_{i=1}^{NH} \mathrm{Re}\left\{Losses_i^k\right\}}{\sum_{i=1}^{NH} \mathrm{Re}\left\{Losses_i^0\right\}} \tag{1}$$

$$ILq^k = 1 - \frac{\sum_{i=1}^{NH} \mathrm{Im}\left\{Losses_i^k\right\}}{\sum_{i=1}^{NH} \mathrm{Im}\left\{Losses_i^0\right\}} \tag{2}$$

Here, $Losses_i^k$ is the total complex line power losses for the *k*-th distribution network configuration during hour *i*; $Losses_i^0$ is the total complex line power losses for the original (no DG) distribution network configuration during hour *i*; and *NH* is the total of hours within the considered horizon.

B. Maximum Voltage Drop

Voltage profile may be improved when most power supplied by DG is delivered to load concentrations. Consequently, the third index (*IVD*) is related to the average maximum voltage drop between each node and the root node at the peak hour of the day. Thus, according to (3), a near-unity value for index *IVD* indicates better network performance. *IVD* is given by:

$$IVD^k = 1 - \frac{\sum_{l=1}^{ND} \max \left| \frac{\left|\overline{V}\phi_0\right| - \left|\overline{V}\phi_j^{k,l}\right|}{\left|\overline{V}\phi_0\right|} \right|_{j=1}^{NN-1}}{ND} \tag{3}$$

where ϕ stands for phases *a* to *c*; $\left|\overline{V}\phi_0\right|$ are the voltages at the root node (equal in magnitude for the three phases) considering the peak hour of day *l*; $\left|\overline{V}\phi_j^{k,l}\right|$ are the voltages at node *j* for the *k*-th distribution network configuration considering the peak hour of day *l*; *NN* is the network number of nodes; and *ND* is the number of days of the analyzed horizon.

C. Reserve capacity of conductors

DG units located in areas where most produced power is delivered to neighboring consumers alleviates the current flows through conductors supplying power from the grid. If these areas are far from the substation, the gain is even greater. On the other hand, when the power produced by a DG unit surpasses the demand downstream from the connection point, it may increase capacity levels beyond distribution line limits. The fourth index (*IC*) gives important information about the average maximum rates of currents flowing through the network relative to the nominal capacity of conductors. Considering those configurations where the current capacity of conductors is not exceeded (reconductoring is out of the scope of this work), close-to-unity values for this index mean reserve capacity for demand growth. *IC* is defined by:

$$IC^k = 1 - \frac{\sum_{i=1}^{NH} \max \left(\frac{\left|\overline{J}\phi_m^{k,i}\right|}{CC\phi_m}, \frac{\left|\overline{J}n_m^{k,i}\right|}{CCn_m} \right)_{m=1}^{NL}}{NH} \tag{4}$$

where $\left|\overline{J}\phi_m^{k,i}\right|$ and $\left|\overline{J}n_m^{k,i}\right|$ are the currents through branch *m* for the *k*-th distribution network configuration during hour *i*; $CC\phi_m$ and CCn_m are the current capacities of conductors; and *NL* is network number of lines.

D. Three-phase and Single-phase-to-Ground Short Circuit

In order to give an indication of how the DG would impact on protection devices the fifth and sixth indices (*ISC*3 and *ISC*1) evaluate the average maximum short circuit current variation between the scenarios with and without DG. A low impact on this concern means close-to-unity values for the indices. *ISC*3, for three-phase to ground fault levels is given by:

$$ISC3^k = 1 - \max \left(\frac{\max \left(\frac{I_{SC}abc_j^{k,l}}{I_{SC}abc_j^{0,l}} \right)_{j=1}^{NN}}{\frac{I_{SC}abc_*^{k,l}}{I_{SC}abc_*^{0,l}}} \right)_{l=1}^{ND} \tag{5}$$

where $I_{SC}abc_j^{k,l}$ is the three-phase fault current value in node *j* for the *k*-th distribution network configuration considering the peak hour of day *l*; $I_{SC}abc_j^{0,l}$ is the three-phase fault current value in node *j* for the distribution network without DG; $I_{SC}abc_*^{k,l}$ and $I_{SC}abc_*^{0,l}$ are the largest three-phase fault current values in the network configuration *k* and its correspondent for the network without DG.

The single phase to ground index *ISC*1 is given by:

$$ISC1^k = 1 - \max \left(\frac{\max \left(\frac{I_{SC}\phi_j^{k,l}}{I_{SC}\phi_j^{0,l}} \right)_{j=1}^{NN}}{\frac{I_{SC}\phi_*^{k,l}}{I_{SC}\phi_*^{0,l}}} \right)_{l=1}^{ND} \tag{6}$$

where $I_{SC}\phi_j^{k,l}$ is the single-phase fault current value in node *j* for the network configuration *k*; $I_{SC}\phi_j^{0,l}$ is the single-phase fault current value in node *j* for the network without DG; and, $I_{SC}\phi_*^{k,l}$ and $I_{SC}\phi_*^{0,l}$ are the largest single-phase fault current

value in the network configuration k and its correspondent without DG.

E. Multiobjective Index

The multiobjective performance index for networks with DG takes into account all indices by strategically giving a weighting factor to each one. This allows them to be related and a unique index to indicate the extent of DG impact, in a global manner, on a distribution network. This can be performed since all impact indices are normalized, i.e., present non-dimensional values from zero to one. The multiobjective performance index (*IMO*) is given by:

$$IMO^k = \begin{Bmatrix} w_1 ILp^k + w_2 ILq^k + w_3 IVD^k + \\ w_4 IC^k + w_5 ISC3^k + w_6 ISC1^k \end{Bmatrix} \quad (7)$$

where,

$$\sum_{i=1}^{6} w_i = 1.0 \ \wedge \ w_i \in [0,1]$$

The importance of one impact index over the others will certainly depend on the analysis required by the electric utility, be it planning or operation, and the determination of suitable values for the weighting factors will rely on the experience of distribution engineers. Consequently, the weighting approach used for calculating the *IMO* gives the decision maker flexibility to decide which technical impacts should receive special consideration regarding the utility's technical perspective, leading to economic decisions that could incentivize (or even disincentivize) DG connection points.

The weighting factors used to illustrate this work are presented in Table I. Considering normal operating conditions, the active power losses received a significant weight (0.33) due to its importance in many applications of DG. The behavior of the voltage profile (*IVD*) and reserve capacity of conductors (*IC*), as a consequence of total loss reduction, also receive major weightings (0.15 and 0.20, respectively) since they show the network's potential for following demand growth without infrastructure investments. Protection and selectivity impacts (*ISC*3 and *ISC*1) received weightings of 0.22 since they evaluate important reliability problems that DG presents in distribution networks.

The emphasis given to the energy losses reflects the economical impact that its reduction may have on the utility's profit. In general, regulatory agencies incentivize –economically– distribution companies to diminish losses in their networks. Thus, if the DG is able to decrease the system's losses, the utility's profit will increase.

The multiobjective index will numerically describe the impact on a distribution network of a DG of a given location and capacity. According to the proposed methodology, close-to-unity values for the *IMO* relates to higher DG benefits.

TABLE I
WEIGHTING FACTORS

ILp	*ILq*	*IVD*	*IC*	*ISC3*	*ISC1*
w_1	w_2	w_3	w_4	w_5	w_6
0.33	0.10	0.15	0.20	0.07	0.15

III. CASE STUDY

A. Test Network

The IEEE 34-bus three-phase medium voltage radial feeder [13] will be used in order to perform the proposed analysis (Fig. 1). Its total demand is 1.7 MW with most of the load concentrated some distance (56 km) from the substation. Construction from ACSR 1/0, 2 and 4 conductors result in X/R ranges from 0.91 to 2.25. The network is simplified by replacing the 24.9:4.16 kV in-line transformer in the original test feeder with a line and modeling the entire feeder at a single voltage level, V_b, of 24.9 kV. The automatic voltage regulator is also not represented due to the presence of DG.

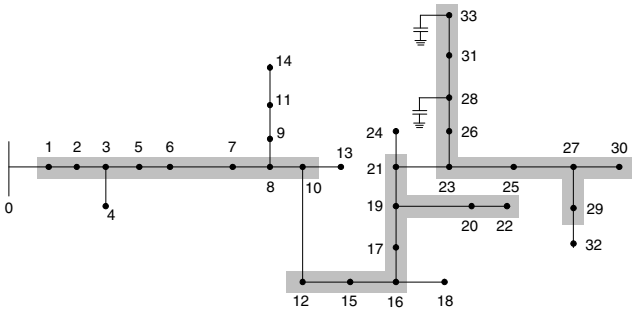


Fig. 1. IEEE-34 test feeder considering one wind speed zone.

B. Load Demand and Wind Power Generation

The typical load profiles are shown in Fig. 2 after adjustment from the design values of peak demand to the actual average value of peak winter demand and minimum summer demand as reported by the Electricity Association in the UK [14]. Moreover, hourly wind speed measurements taken from UK Meteorological Office weather stations in central Scotland in 2003, were used.

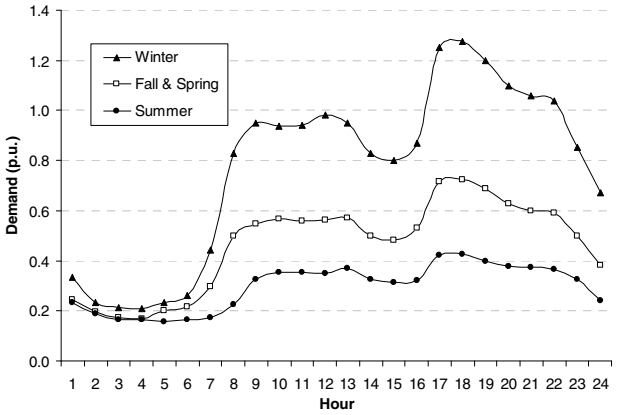


Fig. 2. Seasonal daily load profiles [14].

Geographic characteristics of the region where the network is located, the topology and size of the system under analysis, as well as availability of historical data of wind speeds will be important factors for determining the quantity and range of zones with similar wind characteristics. Initially, this study will solely consider one wind speed zone, as shown in Fig. 1,

where the shadowed areas which indicate possible wind turbine connection points.

Fig. 3 presents the power curve for a 500 kW wind turbine (50 m high) that was used to derive the hourly power output by combining it with relevant wind speed measurements for each wind zone.

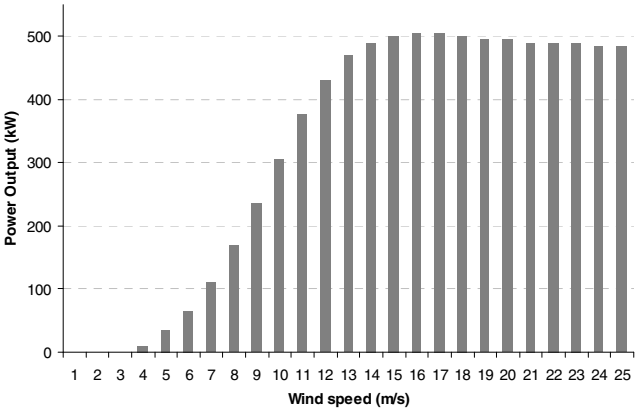
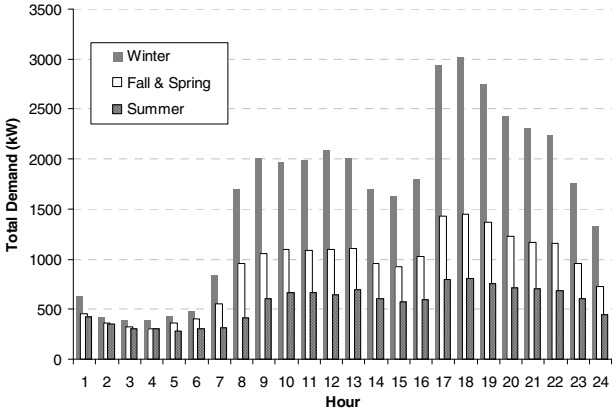


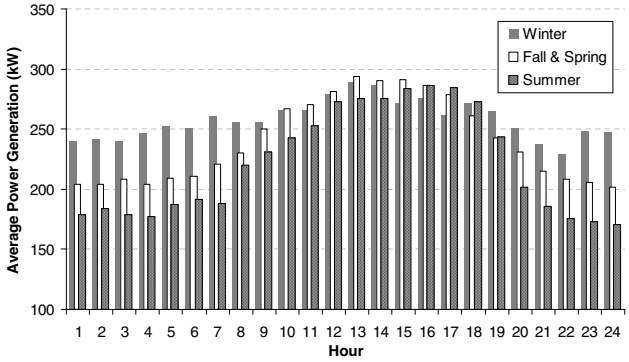
Fig. 3. 500 kW wind turbine power curve.

In order to show some characteristics of the adopted wind speed measurements and load profiles, Fig. 4 shows the seasonal typical patterns for the original (no DG) IEEE-34 test feeder's hourly total demand (including losses) and the hourly average power generation output for a single 500 kW wind turbine (Fig. 3). It is observed in Fig. 4a that, for certain hours, total system's demand is lower than 500 kW. Considering that wind speed measurements for 2003 provide 57 days (16% of the year) with daily average power generation above 400 kW, counter flows through the substation may occur. On the other hand, as shown in Fig. 4b, the typical generation for each season keeps a much lower profile. Consequently, an analysis based on typical wind speeds or power generation patterns, although more practical, could neglect some effects. Thus, given the high variability of this kind of energy source, it is important to properly choose the data that will describe its behavior.

If the approach considers the analysis of both load and generation hourly intervals for the horizon of a year, then it leads to 8760 analysis intervals per year.



(a)



(b)

Fig. 4. Seasonal typical patterns for (a) IEEE-34 test feeder's hourly total demand; and, (b) Hourly average generation for a 500 kW wind turbine (Fig. 3).

In our approach, the analysis was exhaustive using these 8760 intervals, but the number of intervals could be reduced through an appropriate selection of load and generation scenarios, taking into account seasonal and economical parameters, as well as those data with repetitive behavior. For instance, loads may be clustered by off-peak and peak, and each of them considering three loading levels. The most representative seasonal periods should be also considered. In economic terms, according to the regulation, those periods affecting the loads and the generation must be also taken into account. Some countries already incentivize generators to apply different power factor values according to the loading [10].

IV. Applications

Since the approach considers the analysis of both loads and generations hourly intervals for the horizon of a year (in this case 2003), 8760 power flow solutions were required per configuration. To account for the three-phase four-wire topology, the power flow algorithm from [15] was used due to its robustness and swiftness. Loads are modeled as constant power and the load data from [13] is considered to be 1.0 p.u. in the load profile presented in Fig. 2. Short circuit analysis was performed based on symmetrical components and considering the data used in [12]. In order to illustrate how the impact indices (presented in Section 2) vary with location of the wind turbines, the 500 kW wind turbine was located at every connection point in turn. A power factor equal to 0.9 lagging (producing reactive power) was adopted.

Results of all six impact indices, i.e., active power losses (*ILp*), reactive power losses (*ILq*), maximum voltage drop (*IVD*), reserve capacity of conductors (*IC*), three-phase short circuit (*ISC*3) and single-phase short circuit (*ISC*1), are shown in Fig. 5. As expected, the reduction of both active and reactive power losses becomes significant when the generation is located close to the load concentration, i.e., far from the root node. A similar trend is followed by indices *IVD* and *IC*: while better voltage profiles are obtained when the wind turbine is near major loads, a number of line sections conduct less current leading to overall relief on conductors' reserve

capacity. On the other hand, the greater the distance between the generation unit and the substation, the greater the ratio of the maximum fault current with DG to the maximum fault current without DG, and, consequently, the lower the indices *ISC*3 and *ISC*1.

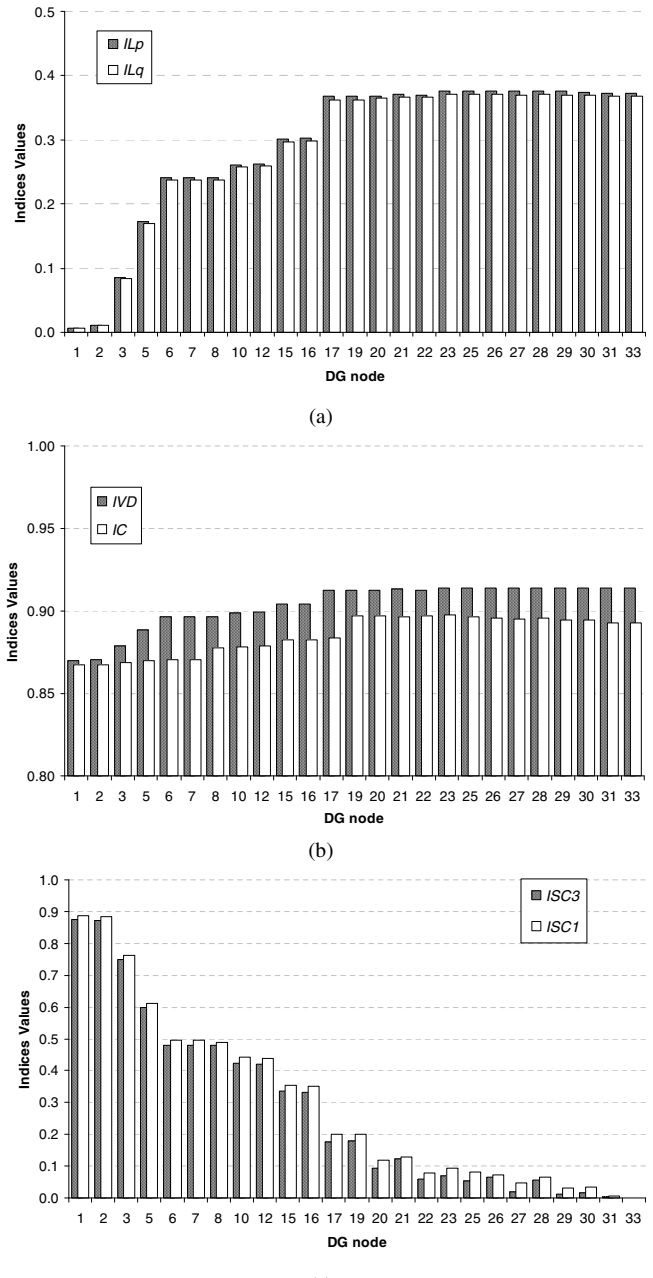


Fig. 5. Impact Indices for each node assuming time-varying loads and DG: (a) *ILp* and *ILq*; (b) *IVD* and *IC*; and, (c) *ISC*3 and *ISC*1.

Table II presents non-normalized results of the indices for two "opposite" configurations: generation at node 1 and node 33. Comparing these results to those obtained for the original case of no DG, it is clear that significant reduction of power losses occurs when the generator is located close to the load. Total active and reactive energy losses diminished up to 37% when the wind turbine was sited at node 33. Also, while the maximum voltage drop and the reserve capacity of conductors did not present much variation with a generator close to the substation, substantial gains were attained for the more distant configuration: *IVD* decreased by 34%. As for the reserve capacity of conductors, an increase of 2% was perceived. These values demonstrate the potential benefits of properly located time-varying power generation for improving voltage profiles and relieving conductor loadings. However, a significant increase of fault current levels, for both three- and single-phase short circuits, occurs when the insertion point is far from the substation. For node 33, the three-phase short circuit maximum current was 13 times larger than without DG with the single-phase fault increasing by 27 times. While distance from the substation may offer many advantages for overall network performance, it also leads to a scenario where protection schemes require special attention. In this way, economic benefits that a given DG configuration may bring to the distribution network, e.g., due to reduction of energy losses, must be contrasted with the "deep" costs [1] associated with protection upgrades.

TABLE II
NON-NORMALIZED IMPACT INDICES – SITING OF DG CLOSE TO (NODE 1) AND DISTANT (NODE 33) FROM ROOT NODE

Impact Index		no DG	DG at node 1	DG at node 33
ILp	(MWh)	974.08	968.06	610.87
ILq	(MVArh)	954.58	948.74	603.66
IVD	(%)	13.06	12.99	8.61
IC	(%)	87.26	86.74	89.25
$ISC3\ \frac{\text{with DG}}{\text{without DG}}$		---	1.60 (4761.9 A/2982.5 A)	12.88 (2252.8 A/174.9 A)
$ISC1\ \frac{\text{with DG}}{\text{without DG}}$		---	3.01 (6415.6 A/2134.9 A)	26.90 (3573.9 A/132.9 A)

The results presented in Fig. 5 are useful for visualizing the trends and behavior of the impact indices, whereas the non-normalized values permit analysis of the actual impact on each technical aspect. Nonetheless, this disaggregated information cannot be used as a decision making tool. Consequently, the multiobjective performance index (*IMO*) becomes a useful tool for assisting distribution engineers in the technical and economic evaluation of DG configurations from a global point of view.

The weighting factors presented in Table I were applied to the indices computed for time-varying demand and generation produce the *IMO* for each DG configuration analyzed. In Fig. 6, these are compared with the *IMO* values achieved using the "static" snapshot approach of [12], considering in this case a 1.0 demand and 500 kW power generation (power factor 0.9 lagging). While values of the two obtained series of *IMO*s cannot be compared since they were calculated differently, the focus should be given to their trends which, as expected, exhibit a major difference between the approaches. In fact, considering the same weighting factors, the "static" approach indicates that the best insertion point for a 500 kW DG unit is at node 19, whereas taking into account the time-varying parameters suggest node 8. The "worst" connection point indicated by the time-varying approach is node 33 which is

opposed to node 1 considered to be a poor choice under the static approach. Thus, for a given node compared to the others, the results of the two methods lead to different performances. In this case, this would appear to indicate that the snapshot overestimates the benefits of connecting DG for most locations whilst underestimating them for DG connected close to the substation.

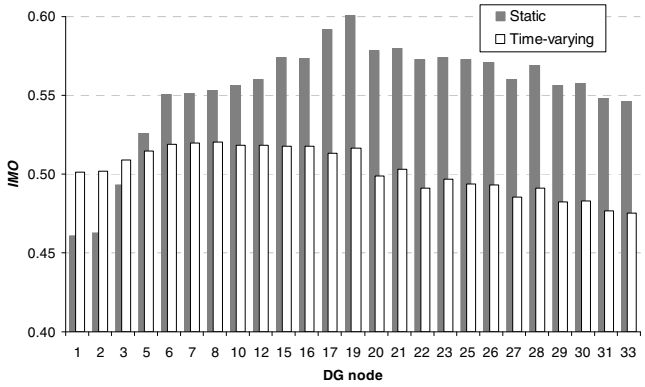


Fig. 6. Multiobjective performance indices (*IMO*) for static (500 kW generation – 1.0 p.u. demand) and time-varying approaches.

On the other hand, it can be argued that a full capacity generation and 1.0 p.u. demand are not representative along the analyzed horizon, and thus cannot be compared with the time-varying approach. Fig. 7 presents the *IMO* values for the static approach considering the annual hourly average values for the adopted wind power generation and demand profiles (power output of 240.1 kW and a load of 0.498 p.u.). Although the *IMO* behavior of the static analysis is somehow more similar to that exhibited by the time-varying results, it still suggests nodes 19 and 1, as the best and worst insertion points, respectively.

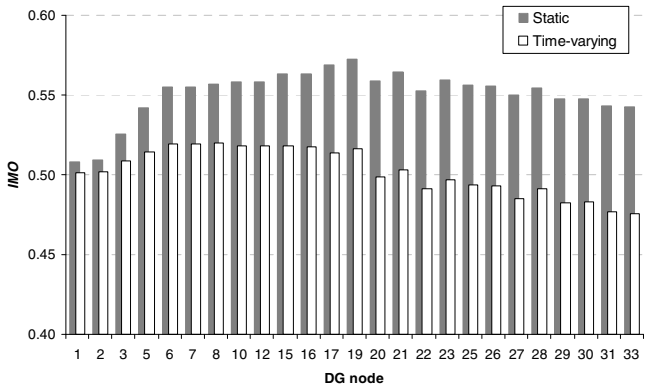


Fig. 7. Multiobjective performance indices (*IMO*) for static (240.1 kW generation – 0.498 p.u. demand) and time-varying approaches.

Table III shows the non-normalized values of the indices computed by the time-varying approach, for the connection points that led to the maximum *IMO*, node 8, and for that suggested by the static approach as the most suitable location, node 19. It can be verified that the first four indices, related to how close the generator is from the load concentration, are actually encouraging node 19 instead of node 8. Indeed, insertion of DG at node 19 achieved a 37% loss reduction, while node 8 solely attained 24%, compared to the original configuration. However, the substantial values of the weighting factors given to both indices *ISC*3 and *ISC*1 make the final *IMO* values to be a compromise among all indices considered. In this way, while some indices were found to be a bit better when inserting a generator at node 19, the rates of short circuit levels were, drastically different at node 8 (around 64% the value of the node-19 rates).

Depending on the geographic characteristics and/or the detail of wind speed data, more than one zone may be identified in a network to differentiate energy patterns. Moreover, zones can also be useful to distinguish nodes where other energy sources may be available.

TABLE III
NON-NORMALIZED IMPACT INDICES FOR THE "BEST" LOCATIONS FOR DG ACCORDING TO THE TIME-VARYING (NODE 8) AND STATIC (NODE 19) ANALYSES

Impact Index	no DG	DG at node 8	DG at node 19
ILp (MWh)	974.08	739.44	616.33
ILq (MVArh)	954.58	727.76	608.92
IVD (%)	13.06	10.36	8.73
IC (%)	87.26	87.80	89.67
$ISC\,3\ \frac{\text{with DG}}{\text{without DG}}$	---	6.70 (2362.7 A/352.5 A)	10.59 (2263.9 A/186.8 A)
$ISC\,1\ \frac{\text{with DG}}{\text{without DG}}$	---	13.77 (3563.9 A/258.8 A)	21.47 (3600.9 A/144.9 A)
IMO	---	0.5201	0.5163

Three wind speed zones are identified in Fig. 8, where zone 3 was that used in the previous analysis. A single wind turbine with the characteristics presented in Fig. 3 would produce 1514.6, 1795.5 and 2103.1 MWh, for zones 1, 2 and 3, respectively, during 2003. The corresponding hourly average power generation outputs are 172.9, 204.9 and 240.1 kW.

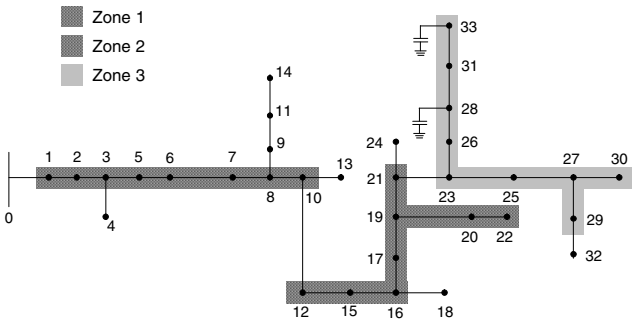


Fig. 8. IEEE-34 test feeder considering three wind speed zones.

Fig. 9 shows the *IMO* values computed for both the time-varying and static analyses, considering the three wind speed zones presented in Fig. 8 and the annual hourly average generation/demand for the latter approach. It is observed that due to the new power generation patterns, those nodes located in zones 1 and 2 present lower *IMO* values than those obtained in Fig. 7. Thus, the time-varying approach now indicates that the most suitable insertion point would be node 12, whereas

the lowest benefits would be encountered with a DG sited at node 22. This result verifies that the *IMO* maintains the compromise mainly between the reduction of energy losses and increase of short-circuit levels. Moreover, again, the static approach presents different nodes with the highest and lowest *IMO* values. In this case, nodes 23 and 1, respectively.

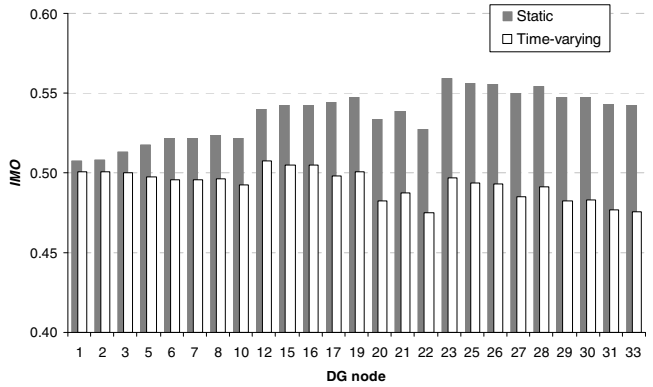


Fig. 9. Multiobjective performance indices (*IMO*) for static (annual hourly averages generation per zone – 0.498 p.u. demand) and time-varying approaches.

V. Conclusions

The variability of production from many DG technologies makes it essential that analyses of networks are not restricted to scenarios where demand and generation are considered to be static. The inherent time-varying behavior of both demand and generation needs to be taken into account in order to avoid over or underestimating the benefits of DG insertion.

A multiobjective performance index that relates impact indices by strategically assigning a weighting factor to each index was proposed. A number of impact indices were addressed in this work, aimed at characterizing the benefits and negative impacts of DG in distribution networks. More impact indices, such as reliability, economics and environmental concerns can be included in the procedure but nonetheless would add complexity.

Despite the limited capability of distribution engineers to specify connection points of DG units, the multiobjective performance index presented in this work provides knowledge of where generation could be beneficial for the distribution network considering the critical issue of load and generation patterns. This flexible methodology can help the decision maker to identify configurations that suit the utility's current concerns by setting the weighting factors accordingly.

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