Assessing the Economic Impact of Distributed Generation on Voltage Regulation in Distribution Networks

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Abstract—This paper presents a methodology for economic assessment of the investments required for maintaining distribution networks within regulatory limits of voltage and voltage step change, while considering the connection of distributed generation (DG). Here, Static Var Compensators (SVCs) are utilized to regulate voltages. A modified voltage sensitivity method aimed at evaluating the effect of DG on SVC deployment, in terms of both location and capacity, is applied. Under liberalized electricity markets, this proposal may provide a common ground for deriving efficient economic signals to either penalize or incentivize DG connection according to its impact on the network’s performance.

Index Terms—Distributed generation, SVC, voltage regulation

I. INTRODUCTION

Due to the advancement of energy conversion technologies such as wind turbines, combined heat and power (CHP), fuel-cells etc, electric generation at distribution level, known as distributed generation (DG), has become an environmentally and economically-attractive alternative. It is expected that the penetration of DG will continue to increase worldwide in the near future.

However, various challenges to distribution network operators (DNOs) are also brought about by the introduction of DG. One of the major impacts, depending on DG operation and the load characteristics of the network, is the potential degradation of voltage profiles [1], [2]. Furthermore, the bidirectional power flows caused by DG could also require the modification of well-established distribution network voltage control mechanisms [3]. Several voltage control strategies considering DG have been proposed [4]-[7]. However, under the liberalized electricity market, DG operation tends to follow the time-varying economic signals. Therefore, without proper economic assessment and incentives given to DG owners, DG is less likely to tune its operation and adopt advanced control schemes to provide voltage support services. Aimed at improving market efficiency, the UK regulator Ofgem requested DNOs to develop new Distribution Use of System (DUoS) charges that reflect the contribution of DG in future network investments [8], [9]. That is, the DG owner would be either rewarded or penalized according to the future impact of DG on the network connected.

Some methods have been proposed to quantify the DG impacts on network losses and investment deferral of electrical lines [10], [11]. Although DG alters the system voltage in a similar manner as it affects network losses and capacities, those methods are not designed for assessing the economic aspects of the voltage issue. Besides, the ability of DG to support network voltages after various contingencies needs to be quantified if DG is expected to continuously provide voltage-supporting services in post-contingency conditions.

Comparisons have been made between DG and SVCs in terms of the ability to provide network voltage by injecting power to the connected bus [4]. Indeed, according to UK regulations, both are capable of responding quickly to support voltages during the transient state after a contingency [12], [13]. In this context, here, an economic assessment of the investments required for maintaining distribution networks within regulatory limits of voltage and voltage step change is performed. The effect of DG on SVC deployment, in terms of both location and capacity, is evaluated by applying a modified voltage sensitivity method.

This paper is structured as follows: Section II gives brief descriptions of how DG could affect system voltages and shows the existing voltage regulations in the UK. The modified voltage sensitivity method is explained in Section III, followed by the proposed algorithm (Section IV). Section V presents the distribution network studied and the corresponding considerations. Results are shown in section 6 and then followed by the conclusions.

II. IMPACT OF DG ON VOLTAGE REGULATION

Fig. 1 depicts a simple two-bus system with DG connected to the load bus. The voltage difference can be calculated based on the following approximate equation:

$$V_1 - V_2 = \Delta V \approx R \cdot P + X \cdot Q$$  \hspace{1cm} (1)

where $R$ and $X$ are the line resistance and reactance respectively, $P$ and $Q$ are the real and reactive power flow through the line. According to (1), the voltage drop between the two buses depends on the direction and magnitude of $P$ and $Q$. Therefore, depending on the relative quantities of DG and load, $V_2$ can be either greater or less than $V_1$. Assuming $P_G$
and \( Q_G \) are in the same direction, increasing DG generation while still below the demand level would result in the rise of \( V_1 \) and \( \Delta V \) decreases. At the condition where \( P_G > P_L \) and \( Q_G > Q_L \), the power flow is reversed and \( V_1 \) would rise above \( V_i \). To ensure the correct functioning of consumers’ equipment, DNOs have an obligation to maintain bus voltages within regulatory limits. In the UK, the voltages are regulated within \( \pm 6\% \) of nominal at 33 and 11 kV.

![Fig. 1. A simple 2-bus system.](image)

Another concern about network voltage is the step change between the pre- and post- steady-states given a disturbance (e.g., loss of DG or circuit), which could become a significant problem as the penetration of DG increases [14]. UK Engineering Recommendation G75/1 [17] defines voltage step change as “Following system switching, a fault or a planned outage, the change from the initial voltage level after all the Generating Unit voltage regulator and static VAR compensator actions, and transient decay (typically 5 seconds after the fault clearance or system switching) have taken place, but before any other automatic or manual tap-changing and switching actions have commenced”. Table I summarizes the maximum voltage step changes allowed after a disturbance in UK distribution system [14].

<table>
<thead>
<tr>
<th>Area</th>
<th>Voltage Fall</th>
<th>Voltage Rise</th>
</tr>
</thead>
<tbody>
<tr>
<td>England and Wales, following secured events</td>
<td>-6%</td>
<td>6%</td>
</tr>
<tr>
<td>England and Wales, following operational switching less frequent than specified in ER P28</td>
<td>-3%</td>
<td>3%</td>
</tr>
<tr>
<td>Scottish Power Transmission Ltd</td>
<td>-6%</td>
<td>6%</td>
</tr>
<tr>
<td>Scottish Hydro Electric Transmission Ltd</td>
<td>-6%</td>
<td>6%</td>
</tr>
</tbody>
</table>

III. MODIFIED VOLTAGE SENSITIVITY METHOD

The method is developed from the conventional voltage sensitivity equations but with the introduction of the two types of voltage constraints described in the previous section. The final location of an extra MVAr of SVC capacity will correspond to that bus providing the largest improvement on the overall system voltages while fulfilling voltage constraints.

The differential equation below can be derived from conventional power flow equations [15]:

\[
\begin{bmatrix}
\frac{dP_i}{dQ_i}
\end{bmatrix} = \begin{bmatrix}
J_{11} & J_{12} & \frac{d\theta}{d\theta}
\end{bmatrix}
\begin{bmatrix}
J_{13} & J_{14}
\end{bmatrix}
\begin{bmatrix}
\frac{dP}{dV}
\end{bmatrix}, \quad i = 1...N
\]

(2)

where \( N \) is the number of buses in the network excluding the slack bus; \( J_1 = \frac{\partial P}{\partial \theta} \), \( J_2 = \frac{\partial P}{\partial V} \), \( J_3 = \frac{\partial Q}{\partial \theta} \), \( J_4 = \frac{\partial Q}{\partial V} \) are the \( N \times N \) sub matrices of the Jacobian matrix.

Since we are interested in finding the voltage changes due to SVC connection, (1) can be rearranged as follows:

\[
\begin{bmatrix}
\frac{d\theta}{dP}
\end{bmatrix} = \begin{bmatrix}
K_{11} & K_{12} & \frac{dP}{dP}
\end{bmatrix}
\begin{bmatrix}
K_{13} & K_{14}
\end{bmatrix}
\begin{bmatrix}
\frac{dQ}{dV}
\end{bmatrix}
\]

(3)

where \( K_{1}(i,j) = (J_{i} - J_{i}J_{j}^{-1}J_{i})^{-1}, K_{2}(i,j) = -J_{i}^{-1}J_{i}(J_{i} - J_{j}^{-1}J_{i})^{-1}, K_{3}(i,j) = (J_{i} - J_{j}^{-1}J_{i})^{-1} \).

In our case, only the changes of bus voltages due to reactive power injections are of interest, therefore (3) is further simplified to:

\[
\begin{bmatrix}
\frac{dV}{dP}
\end{bmatrix} = K_{1}(i,k)
\]

(4)

The change in voltage of each bus within the network due to the SVC connected at bus \( k \) can be derived as follows:

\[
\begin{bmatrix}
\frac{dV}{dP}
\end{bmatrix} = \begin{bmatrix}
K_{1}(i,k)
\end{bmatrix}
\begin{bmatrix}
dQ \end{bmatrix}, \quad k \in \ldots N
\]

(5)

To introduce the steady-state voltage and voltage step change constraints, let \( V_{\text{no SVC}} \) and \( V_{\text{SVC}} \) be the steady-state voltages at bus \( i \) before and after the installation of a SVC at bus \( k \) respectively. Let \( \Delta V_i \) be the voltage change at bus \( i \) after taking the constraints into account. Thus,

\[
V_{\text{no SVC}} + dV_i = V_{\text{SVC}}
\]

(6)

\[
\Delta V_i = V_{\text{max}} - V_{\text{SVC}} \quad \text{If } V_{\text{no SVC}} < V_{\text{min}} < V_{\text{SVC}}
\]

(7)

where \( V_{\text{max}} \) and \( V_{\text{min}} \) are the upper and lower voltage limits for either steady-state voltage or step change constraints depending on the analysis. In this way, during normal operating conditions, \( V_{\text{max}} \) and \( V_{\text{min}} \) are equivalent to the steady-state statutory limits, while following a contingency, if the voltages do not fall out of the steady-state limits, then the values are bound by the maximum voltage change allowed. Thus, extra MVAr of SVC capacity, \( dQ \), would be connected at the bus that maximizes the following equation:

\[
\text{Max}(\sum_i \Delta V_i)
\]

(8)

IV. PROPOSED ALGORITHM

Developed in the Python computer language to interact with the PSS/E power system analysis software, the proposed algorithm is comprised of three basic steps described below. The corresponding flow chart is presented in Fig. 2.
Step 1. Read network data and perform an AC power flow to evaluate the voltage profile during normal operation. In case voltage drops (or rises) result in values outside the limits, execute the modified voltage sensitivity method to determine the SVC capability required to satisfy the voltage requirements.

Step 2. The network voltage profile after each possible contingency is examined. Loss of a single line, transformer, load or generator are considered. For each contingency event, the modified voltage sensitivity method is performed to assess the siting and sizing of SVCs connected throughout the network. The total cost of the required SVCs in the case is calculated.

Step 3. Finally, the analysis performed in the previous steps will now consider DG units at specific locations. The economic impact of DG will correspond to its ability to offset the need for SVCs and therefore, to decrease the consequent investment.

Fig. 2. Flow chart of the proposed algorithm.

V. APPLICATION

A. Network model and assumptions

The methodology is applied to the distribution network shown in Fig. 3, a sub-network of the UK Generic Distribution System “EHV Network 2” developed by [16]. Power is supplied to the 33 kV circuit via three parallel 132/33 kV transformers. Major loads are at 11 kV level and connected to either single or double 33/11 kV transformers. Table II shows the demand characteristics of this network. Although the circuit is meshed, some buses present poor voltage profile.

To perform the simulations, the following considerations are taken into account:

1. Thirty possible contingencies (Table III) are analysed. This includes loss of a single line, transformer and DG.
2. Voltage drop and rise must not exceed ±6% of the nominal value. Voltage step change is limited to ±6% of the voltage during normal operating conditions, i.e., before any contingency.
3. SVCs can be connected at any buses apart from bus 106. One MVAr of SVC costs $30k and $35k when connected to 11 and 33kV circuits, respectively.
4. DG scenarios will consider non-intermittent generation with capacity up to 20 MW. Here, the availability and reliability issues are neglected but an approach to account for these considerations is shown in the appendix.
B. Influence of DG Locations

Three different cases considering the connection of a single 20 MW DG unit (operating at unity power factor) to the 33 kV buses 314, 323 and 324, are studied separately. To isolate the effect of voltage control by auto-tap transformers these initial assessments employed fixed transformer tap settings; the effect of transformer tap control settings is explored in Section IV.D.

Fig. 4 shows the resultant lower and upper SVC capacity required at each 11 kV load bus in order to comply with the constraints for voltage drop and rise, and voltage step change (contingencies). In the absence of voltage control from the 33/11 kV, the capacity of SVCs installed at the 11 kV load buses accounts for approximately 90% of the total capacity installed throughout the network. The numbers on the top and bottom of each bar indicate the maximum capacitive or inductive (negative in this case) reactive power provided by the SVCs. The results show that different locations of DG change the types of critical contingencies hence affecting the maximum SVC capacity installed at each bus. Bus 1118 is most prone to voltage problems therefore it is the most effective site to place SVCs.

Table 4 shows the total SVC installations and costs corresponding to different DG locations. DG at bus 314 and bus 323 induces apparent benefits by saving around 40% of the investment costs required of the case without DG, although bus 324 is less beneficial. Although the average SVC capacity at bus 1118 when DG is at bus 314 is less than when the generator is located at bus 324, the contribution of DG in supporting voltage at bus 1118 after contingency C9 (outage of line 304-324) is very limited in the former case. Indeed, the DG unit connected to bus 324 can not effectively decrease the SVC capacity required at bus 1118 mainly due to the constraints imposed by contingency C9. The voltage step change becomes influential when DG is connected to bus 323. The contingency C28 (disconnection of load at 1110) could cause abrupt voltage rise at bus 1118 and the presence of DG tends to further worsen the situation. Therefore, in this case, after C28 SVC at bus 1118 is required to produce 1.4 MVar inductive reactive power to prevent the violation of the voltage step change constraint.

Table IV shows the total SVC installations and costs based on DG locations.

C. Influence of DG capacity and power factor

Here, the influence of DG capacity is examined by considering a range of DG sizes at bus 332 operating at several different power factors (0.9 leading, 0.9 lagging and unity.). Fig. 5 shows that at lagging and unity power factor the cost saving increases with DG capacity. More lagging operation increases the benefit with, for example, a 20 MW DG unit at 0.9 lagging power factor could contribute an additional 20% cost reduction compared to the equivalent DG at unity power factor.

The high X/R ratio of lines for this particular distribution network and DG operating at leading power factor resulted in little impact on the voltage profile. For those generators that absorb reactive power (inductive generators), power electronics equipment could be installed in order for DG to operate at the required power factor to support network voltages. Results show that significant benefits can be obtained by adopting lagging power factor. Therefore, it might be beneficial for DNOs to create incentives to DG owners for them to provide voltage support services by adopting the most suitable power factor strategy for the network.

In general, the quantified economic benefits for the studied cases increase with the DG capacity, mainly with unity and lagging power factor. However, such gains become relatively stable as DG capacity increases beyond 12 MW. The cause can be observed in Fig. 6, which indicates the range of SVC operation at each load bus according to different DG capacities operated at 0.9 lagging power factor. As the DG output increases, the contingency of loss of DG (C30) becomes the critical event causing maximum capacitive power required by SVCs at some buses. Since C30 becomes critical, further increase in DG size has no effect on reducing the
maximum capability required of the SVCs. Besides, the loss of load at bus 1118 (C28) would become more severe causing violation of the voltage step change constraint, which leads to additional SVC capacity to produce inductive reactive power. Further cost reduction is possible. The benefit can be observed in Figure 8. If such a control strategy is established, the quantified benefits for the DG would be increased further by $180,000 (6 \times 30)$. 

**D. Influence of transformer tap-changer settings**

In this case different settings of the network tap changers are applied to the distribution network. The results would give the planner an idea about the suitableness of current voltage control mechanism when accommodating the 20 MW DG at bus 323. Three different voltage settings for each tap changer of the 33/11 kV transformers are adopted. In the first case T1, the tap changers are set to regulate the secondary bus voltage between the steady state limits, i.e. ±6% of nominal. The voltage tolerances then changed to ±1% of nominal in the second case T2, which is the more common and practical situation. For the third case, T3, it is assumed the operator requires the tap changers to regulate bus voltages between 1.02pu to 1.06pu, to boost network voltages to minimize the additional investment required.

The results are shown in Fig. 7. T0 indicates the initial cases where tap settings are fixed. In the case without DG, enabling the existing transformer tap changers decreases the investment further by 30 to 40%. However, the presence of DG has significant impact on the quantified benefit. The cost is reduced by 60% when T3 is applied, while T1 is the worst control scheme which, when combined with DG, the overall cost increases slightly. Fig. 8 indicates the capacity of SVC installed in the cases of T1, T2 and T3 including DG. From T1 to T3, in general, the maximum capacitive power required by SVC of each bus reduces. However, as loss-of-load contingencies become a more critical event, an extra few MVar of inductive power from the SVC, especially at bus 1118, is required to avoid unacceptable voltage step change.

In the case of T3, C28 (loss of load at bus 1118) is the contingency that causes the maximum amount of inductive power support by SVC at bus 1118. Since DG has the ability to control its connected bus bar voltage, if, after C28, the DG is able to keep the voltage rise within the statutory limits,
VII. APPENDIX – AVAILABILITY ASSESSMENT OF DG

Engineering Recommendation P2/6 provides lookup tables to search for the capability of DG as a function of DG availability and number of units. The following table shows the ‘F factor’ for non-intermittent types of DG. (a detailed explanation of the tables derivation can be found in [17]):

<table>
<thead>
<tr>
<th>type of generation</th>
<th>number of units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Interfuel gas</td>
<td>65</td>
</tr>
<tr>
<td>CCGT</td>
<td>63</td>
</tr>
<tr>
<td>CHP</td>
<td>40</td>
</tr>
<tr>
<td>Waste to energy</td>
<td>50</td>
</tr>
</tbody>
</table>

For example, two 20 MW DG of CCGT type could be expected to generate the following amount after contingency with high confidence:

DG Contribution = 0.69 × 2 × 20 = 27.6 MW

REFERENCES


BIOGRAPHIES

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