Optimal Utilization of Voltage Controlled Resources in Distributed Generation

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Abstract— Distributed generation (DG) is increasing in penetration on power systems across the world. In rural areas, voltage rise limits the permissible penetration levels of DG. Another increasingly important issue is the impact on transmission system voltages of DG reactive power demand. Here, a passive solution is proposed to reduce the impact on the transmission system voltages and overcome the distribution voltage rise barrier such that more DG can be connected. The fixed power factors of the generators and the tap setting of the transmission transformer are determined by a linear programming formulation. The method is tested on a sample section of radial distribution network and on a model of the all island Irish transmission system illustrating that enhanced passive utilization of voltage control resources can deliver many of the benefits of active management without any of the expense or perceived risk, while also satisfying the conflicting objectives of the transmission system operator.

Key words: Distributed Generation, Radial Distribution Systems, Optimization Techniques, Linear Programming, Ladder Iterative Technique method, N R Method, FDLF Method

I. Introduction

The penetration of distributed generation (DG) is rapidly increasing on power systems across the world. DNOs(Distribution Network Operators) must now facilitate the connection of DG onto networks which were not designed for generation, while maintaining the DNO’s primary role of delivering a secure and reliable supply of electricity to consumers.

II. Distributed Generation

Distributed Generation (DG) is that which is connected to the distribution network and will often be connected both geographically and electrically close to consumers. This radially tapered distribution network exhibits increasing resistance per unit length towards its edges. As a consequence, real power flow has a greater proportional effect on bus voltages here than closer to the transmission network where larger conductors are used with consequently less resistance. DG has implications for voltage quality and the safe and proper functioning of the distribution Network. Sitting generation near points of demand can reduce the transmission and distribution losses caused by the resistance of the power lines, cables and transformers. Most demand is on the distribution network and thus connecting generation to a point nearby the load on the distribution network will tend to cause the least losses assuming the generation does not greatly exceed the local demand. The main technical barrier to DG on distribution networks has been found to be voltage rise due to significant active power injections from DG It is mainly an issue on rural networks due to their high impedance and low *X/R* ratio.

III. Voltage Rise

There has recently been much interest in connecting small generators, between 200 kW and l0 MW, deep within distribution systems. These networks are, by tradition, passive networks. They were designed to pass power from the national grid system, down the voltage levels, to LV customers. They were generally not designed for the connection of generators. There are many technical issues that must be considered when connecting a generating scheme to the distribution system, such as:

- thermal rating of equipment
- system fault levels
- stability
- reverse power flow capability of tap-changers
- line-drop compensation
- steady-state voltage rise
- losses
- power quality (such as flicker, harmonics)
- Protection.

The steady-state voltage rise resulting from the connection of these generators can be a major obstacle to their connection at the lower voltage levels. The permitted voltage variations for systems between 50V and 1000V are ±10% of nominal voltage. And the steady state voltage of systems between 1000V and 132 kV should be maintained within ±6% of the nominal voltage.

When a generator is to be connected to the distribution system, the DNO will consider the worst case operating scenarios and ensure that their network and customers will not be adversely affected. Typically, these scenarios are:

- no generation and maximum system demand
- maximum generation and maximum system
- maximum generation and minimum system demand

Some DNOs take into account the diversity of the local load and consider the system with the minimum expected demand. Others do not, and assume no load as the worst case scenario

A. Distribution Systems With No Embedded Generation

To transmit power from an 11 kV primary substation to a typical LV connected customer some distance away will require the voltage at the primary substation to be higher than the voltage at the point of connection of the customer to the 11 kV system. This is explained using Panel 1.

Generally the *X/R* ratio of an 11kV overhead line tends to be low, so neither of the terms *RP* or *XQ* can be neglected. This, coupled with the fact that the reactive power pushed down the line is usually much lower in magnitude than the power (assuming the customer imports reactive power), leads to there being a voltage drop along the line from the primary substation to the point of connection of the customer.

To demonstrate this, consider the following example (Fig.1): connected to a primary substation is a 20 Km long, 11kV overhead line, comprising 16 mm^2 copper conductors. Every 4 Km along the line is a three-phase load of l00 kW and 20 KVar. As the distance from the primary substation increases the voltage falls. With the primary substation at nominal voltage (11 kV), the voltage at far end of the line falls to 10.3 kV (6% below the nominal voltage). This is right on the permitted limit. If the line had been longer or the load greater, the voltage would have fallen even further.

To maintain system voltages within permitted limits, DNOs often maintain primary substations above nominal voltage using automatic voltage control (AVC), on-load tap-changers and line-drop compensation. Controlling the primary substation, in this example, to 103% and 106% of the nominal voltage (11.3 kV and 11.7 kV) maintains the end of the 11 kV line well within the permitted voltage limits.

Although the Electricity Supply Regulations allow voltage variations on the 11 kV system of ±6%, DNOs often impose limits of ±3% at the planning stage. This is in order to maintain the LV connected customers within the permitted +10% and -6% of nominal voltage. In this generic study the ±3% planning limit is ignored. The 11 k V system voltages are allowed to vary by ±6% of nominal voltage, to more clearly demonstrate the effect of connecting a generator.

B. Effect Of Connecting Generation To Distribution

Connecting a generator to the distribution system will affect the flow of power and the voltage profiles. To export its power, a generator is likely to have to operate at a higher able to absorb a significant amount of reactive power. This is explained using Panel 2.

As the *X/R* ratio of the 11 kV line is small, neither *RP* nor *XQ* is negligible. The *XQ* term may be positive or negative, depending on whether the generator is exporting or importing reactive power. However, as the magnitude of the reactive power will be small compared to that of the power (unless some form of compensation is used), the RP+XQ term will tend to be positive. Thus, the voltage at the point of connection of the generator to the 11 kV system will rise above that of the primary substation.

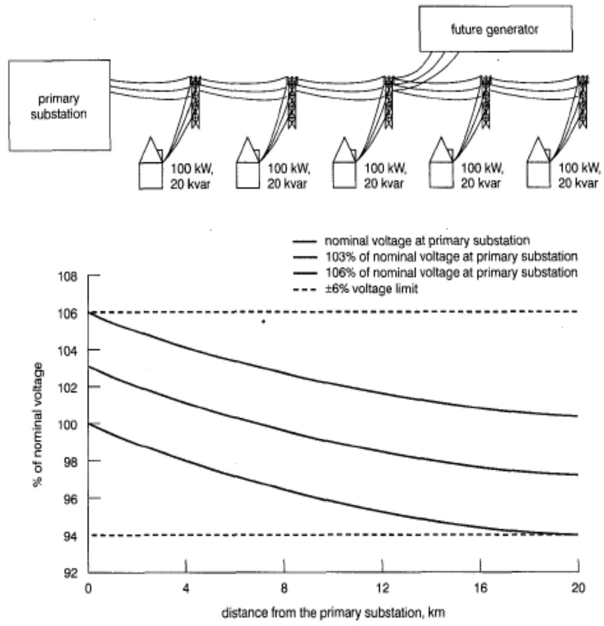

Fig. 1: Voltage profile along the heavily loaded 11kV over head line

To demonstrate this, a 300 kW generator (operating at unity power factor) is connected at 12 Km from the primary substation (controlled at 103% of nominal voltage). The output of the generator is equal to the downstream demand, so the direction of the power flow from the primary substation is not altered. The voltage falls as the distance from the primary substation increases, as before. But the magnitude voltage than the primary substation, unless it is of the voltage drop is less profound (Fig. 2). Increasing- the –generation to 1MW reverses the flow of power along the line, from the generator towards the primary substation. The voltage at the generator rises above that elsewhere, thus allowing the power to be exported in both directions. In this example, the voltage in some parts of the system rises above the permitted ±6% voltage limit.

The voltage rise is more onerous when there is no demand on the system, as all the generation is exported back to the primary substation. With 1MW of generation connected, the voltage rises to 112% of nominal. This suggests that it is the voltage rise during periods of no/minimum demand that limits how much generation can be connected.

When connecting a generator to the distribution system, a DNO must consider whether the power may be exported back through the primary substation and must ensure that the transformer's tap-changers are capable of operating with a reverse power flow.

C. Counteraction Of Voltage Rise

If the connection of a generator to an 11 kV overhead line causes an excessive voltage rise, there are several techniques that can be employed to alleviate the situation, for example:

- reduce the primary substation voltage
- allow the generator to import reactive power (reducing the RP+XQ term)

- install auto transformers, or voltage regulators as they are often called, along the line (resetting the voltage along the line)
- increase the conductor size (reducing the resistance)
- constrain the generator at times of low demand (reducing the transmitted power)
- A combination of the above.

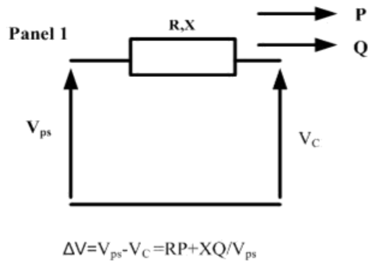

Fig2: active and reactive power flow from substation to customer connected point

Where

V_{ps} is the primary substation voltage

V_C is the voltage at the customer connection point

R, X are the resistance and reactance of the over-head line

P, Q are the power and reactive power transmitted from the primary substation into over-head line

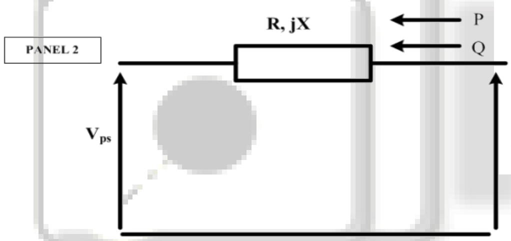

Fig. 3: active and reactive power power flow from customer connection point to the substation

$\Delta V= V_{GEN}- V_{ps}=RP+XQ/ V_{GEN}$

Where

V_{ps} is the primary substation voltage

V_{GEN} is the voltage at the generator connection point

R,X are the resistance and reactance of the over-head line

P,Q Are the power and reactive power transmitted from the primary substation into over-head line

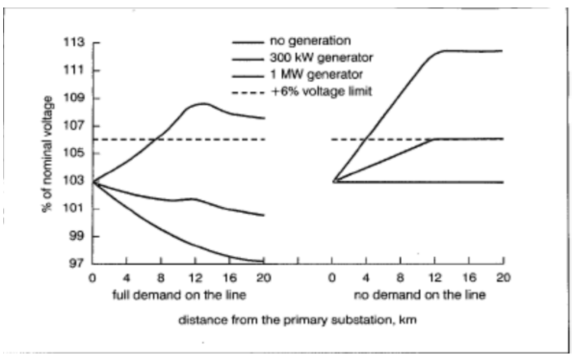

Fig4: Effect of connecting a generator on voltage profile along the 11KV line

D. How Much Generation Can Be Connected To An 11 Kv Over-Head Line?

The level of generation that can be absorbed onto the distribution system is determined by many factors, such as:

- voltage level
- voltage at the primary substation
- distance from the primary substation
- size of conductor
- demand on the system
- other generation on the system

S.NO.	Location of Connection	Maximum Capacity(MW)
1	Out on 11 kV network	1-2
2	11 kV substation bus bar	8-10
3	Out on 33 kV network	12-15
4	33 Kv GSP substation bus bar	25-30
5	On 132 KV network	30-60

IV. METHODOLOGY

A. Objective Function

The calculation of the enhanced voltage control settings requires a range of factors to be included in the formulation of the objective function and constraints. The decision variables are Q_i the generation reactive power and ΔV_{Tap} , the target voltage setting at the on load tap changer at the substation's transformer which minimizes the reactive power from DG. The enhanced settings are determined using a linear programming (LP) formulation. The objective of the optimization is to maximize the reactive power injections across all buses with a reactive power resource. This objective is chosen as it optimizes the system from both the distribution and transmission perspectives, i.e. it will find a solution that satisfies the distribution voltage constraints (to satisfy the DNO), with the maximum possible reactive power injection (to satisfy the TSO).

1) Transmission System Impact:

The maximization of reactive power injections on the distribution network is chosen as the objective because it is equivalent to minimizing reactive power import from the transmission system and will lead to the minimization of the impact on the transmission system voltages. Increasing penetrations of DG on distribution networks are beginning to cause concerns for TSOs. In particular, the reactive power demanded by DG is presenting a drain on the transmission systems reactive power resources, leading to lower voltages on the system and increased risk of voltage instability. As more DG is brought online in rural regions of the system; there is often a deficit of dynamic reactive generation and voltage performance suffers as a result. From a transmission system perspective, operating points where DG output is at its maximum and demand is low are of increasing concern. At these operating points, DG is displacing large amounts of conventional generation which traditionally would have been utilized for voltage control. As a result, the minimization of reactive power import from the transmission system reduces the demand on the transmission system voltage control resources.

2) Dg Capacity:

On voltage constrained distribution networks, generators at voltage sensitive buses require inductive power factors, i.e., act as reactive power sinks. The maximization of reactive power injections will determine the reactive power resources that satisfy the constraints with the least amount of reactive power demand. The permissible capacity of DG that may be connected without network upgrade or the implementation of an active control scheme will thus be increased.

The objective function (J (MVAr)) is given as

$$Max_{ij} = \sum_{i=1}^{N} [LF]_i Q_i \qquad (1)$$

Where Q_i and $[LF]_i$ give the generation reactive power and load factor of the resource at the i^{th} bus and N is the number of buses. The optimization is calculated at the maximum generation, minimum load and zero generation, maximum load operating points. Maximum generation, minimum load is the worst case scenario for voltage rise on distribution networks, hence if the voltage rise constraint is obeyed at this point, it will be obeyed for all possible operating points. A low *X/R* ratio results in a greater coupling between active power and voltage, which makes voltage rise a particular problem on such networks. The load factors give the average output of each resource and are employed here to calculate the average reactive power of the reactive resources. They weight each resource according to its average output and thus those resources with higher average output will, where possible, be allocated higher reactive power output (less inductive).

The diversity of energy resources and the correlation of their outputs will hence have an impact when the temporal variation of output is considered. important factor is that the reactive power capability of the generators decreases with active power output, according to the typical *P-Q* relationship for generators when operated at a fixed power factor. This has the effect that as the active power output (which is the cause of voltage rise) reduces; the reactive power which is used to counteract this effect also decreases. This formulation can also take account of any existing or proposed reactive power resources on the networks, allowing the calculation of their enhanced setting.

B. *Reactive Power Capability*

The reactive power limits of the generation are added to the formulation as a constraint, given by

$$Q_{Mini} \le Q_i \le Q_{Maxi} \qquad i \forall N \qquad (2)$$

Where Q_{Mini} and Q_{Maxi} are the minimum and maximum reactive power of the generator at the i^{th} bus. Negative values for Qi indicate inductive reactive power (Ind.) and positive values capacitive reactive power (Cap.). Typically, distribution codes require all generators connecting to the network to be able to operate between a given band of lagging and leading power factors. In Ireland, the U.K., and other countries, DG has generally operated at a fixed power factor, with a value of 0.95 (inductive) being a typical setting. Here, it is assumed that all generation on the network satisfies these requirements.

Voltage Level:

The method is formulated assuming that there is existing DG installed on the network section. These generation capacities and load levels are employed to calculate the voltage level before the reactive power injection from the generators. Key parameters in the method's LP formulation of the voltage constraint are the reactive power bus voltage sensitivities and the transformer tap changer setting, a description of each is given now.

1) Reactive Power Bus Voltage Sensitivities:

The voltage The sensitivity of the distribution bus voltages to reactive power (ρ_{ijk} , *KV/MVAR*) play a key role in determining at what level the power factors should be set. ρ_{ij} gives the voltage sensitivity of the j^{th} bus to reactive power at the i^{th} bus and V_{Max} gives the maximum permissible voltage. They show how much the voltage changes per MVAr change in reactive power. Reactive power from a generator can significantly affect not only the bus to which that generator is connected but also to other nearby dependent buses.

sensitivities are dependent on the structure and impedance of the network. In radial distribution systems, feeders are separated by normally open points which define the normal feeder configuration. The N-1 feeder configurations are also included here. Indeed, the DNO may decide to move the normally open points for various operational reasons. The reactive power bus voltage sensitivities are therefore calculated for both the normal and N-1 feeder configurations. These N-1 configurations often present a reduced margin for voltage rise, hence it is important that they are considered.

The sensitivities are calculated through ac load flow analysis.

The reactive power injection is added incrementally at each bus in turn and the voltage recorded.

2) Transformer Tap Changer:

The transformer at the bulk Supply point (BSP) is equipped with an on load tap changer, as is generally the case. The corresponding target voltage is commonly set to above nominal values to ensure that there are no low voltage conditions at the end of the feeders. In some cases there may be scope to lower this setting and increase the voltage margin for DG. The tap changer setting is included as a variable in the formulation. It is given by ΔV_{Tap} in p.u. and can vary according to the constraint given in

$$-0.1 \le \Delta V_{Tap} \le 0 \qquad (3)$$

where 0 p.u. indicates an unchanged tap setting from its default value at its upper limit, with a lower limit of 0.1 p.u. For the voltage constraint to be satisfied the voltage at each bus must be kept within its upper and lower limits. The critical operating points in each case are(maximum generation, minimum load) and (zero generation, maximum load), respectively.

Upper Voltage Limit:

The upper voltage limit (in p.u.) is given as

$$V_{Baseupi} - \Delta V_{Tap} + \sum_{j=1}^{N} \mu_{ij} P_j + \sum_{j=1}^{N} \rho_{ij} Q_j \le V_{\max i} \qquad (4)$$

Where μ_{ij} and P give the active power voltage sensitivity and the active power, respectively.. It is the voltage rise from the generators that is of interest here. The base voltages $V_{BaseUpik}$ are therefore calculated under minimum load conditions.

4) Lower Voltage Limit: The Lower Voltage Limit (In P.U.) Is Given As

$$V_{Baselowik} + \Delta V_{Tap} \ge V_{Mini} \qquad i\forall N, K\forall F \qquad (5)$$

V_{min} is the lowest permissible voltage. The relevant operating point in this case is zero generation, maximum load conditions, being the worst case scenario for low voltage.$V_{Baselowk}$ is calculated for each bus for the maximum load, zero generation scenario. This scenario represents the maximum voltage drop that will be experienced on the network. Both of these constraints must be satisfied under N and N-1 conditions. To achieve this the active power and reactive power sensitivities and the upper and lower base voltages (insert 16,) are calculated for a set of F possible N and N-1 feeder configurations. This leads to multiple instances of (4) and (5)

IV. TEST SYSTEMS

The methodology is applied to a sample radial section of the Irish 38-kV distribution network; the impact on the transmission system is determined by modeling the all island Irish transmission system. These models are separate due to the computation requirements of a combined model.

The distribution network section analyzed is a typical rural Section of the Irish 38-kV distribution network, shown in Fig.3 the normally open points, labelled N.O. are closed under N-1 feeder conditions. Such conditions arise on this network when, for example, the line Tx-A is switched out for maintenance. It is assumed that each generator is connected to the network via a 5-km overhead line. The rating of the substation 110/38-kV transformer is 31.5 MVA and the maximum load experienced on the system is 15.5 MW. The initial target voltage at the secondary of the substation transformer is 41 kV (1.08 p.u.). The statutory voltage limits are ±10%.

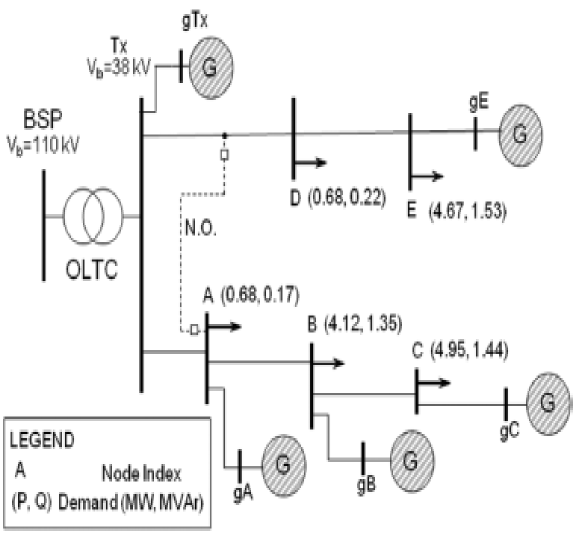

Fig 5: A 38-kV five-bus radial distribution network diagram (max. load level).

VI. LOAD FLOW RESULTS

From the given data of the sample distribution system, calculated load flow for three different conditions (1.maximum generation, minimum load .2.maximum generation, maximum load and 3.no generation, maximum load) in with three different methods 1.ladder iterative technique method, 2.N-R method, 3.FDLF method.

For ladder iterative technique method code was generated in M.file. N-R method and FDLF method also done using the Mat lab.

Max. Gen and Max. Load	**Max. Gen and Min. Load**	**No. Gen and Max. Load**
V_a=38.008∠-0.1042	V_a=38.288∠0.0944	V_a=37.599∠-0.2949
V_b=37.85∠-0.4546	V_b=38.279∠0.02505	V_b=36.528∠-1.135
V_c=37.153∠-1.3566	V_c=39.05∠0.2582	V_c=34.839∠-2.7127
V_d=37.675∠-0.3363	V_d=38.026∠0.0776	V_d=37.328∠-0.5143
V_d=36.919∠-1.2049	V_e=37.991∠0.6719	V_e=35.466∠-2.0424

Table I: Ladder Iterative Technique Method

Max. Gen and Max. Load	Max. Gen and Min. Load	No. Gen and Max.Load
V_a=38∠-0.0893	V_a=38∠0.4934	V_a=37.573∠-0.315
V_b=38∠-0.6495	V_b=38∠1.2970	V_b=36.55∠-1.1549
V_c=38∠-2.4997	V_c=38∠1.7781	V_c=34.81∠-2.7342
V_d=37.938∠-0.699	V_d=37.977∠0.141	V_d=37.31∠-0.5237
V_d=38∠-2.6712	V_e=38∠0.6572	V_e=35.451∠-2.051

Table II: NRLF Method

Max. Gen and Max. Load	Max. Gen and Min. Load	No. Gen and Max. Load
V_a=38∠37.2856	V_a=38∠0.472	V_a=37.57∠-0.3131
V_b=38∠38.832	V_b=38∠1.2515	V_b=36.55∠-1.1505
V_c=38∠40.619	V_c=38∠1.7196	V_c=34.81∠-2.7379
V_d=1.547∠-155.2	V_d=37.972∠0.143	V_d=37.31∠-0.5194
V_d=38∠-3294.451	V_e=38∠0.63878	V_e=35.45∠-2.0485

Table III: FDLF Method

VII. CONCLUSION

With distributed generation the minimization of reactive power import from transmission system reduces the burden on the primary substation. Maximum generation with minimum load, which causes the voltage rise at the connection point, needs careful attention. In distribution system a low *X/R* ratio results in a greater coupling between active power and voltage, should be handled effectively. The reactive power generation at the connection point should be in limit, as the reactive power from a generator can significantly affect not only the buses to which that generator is connected but also to nearby other dependent buses.

VIII. FUTURE WORK

The load flow solution for the given sample network using Ladder iterative technique method, Newton raphson load flow method and Fast decouple load flow method. Has been done. Next step is to apply the described methodology to a sample radial distribution system. The optimized method is going to solve using any linear programming solver and enhancing the utilization of voltage control resources with optimization technique to increase the penetration of distributed generation on the distribution networks.

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