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Enhancement of Network Capacity by Widespread Intelligent Generator Control

ENHANCEMENT OF NETWORK CAPACITY BY WIDESPREAD INTELLIGENT GENERATOR CONTROL

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INTRODUCTION

Electricity networks are called on to accommodate more and more generation capacity in order to supply the increasing demand. Social, planning and environmental reasons hinder the expansion of the existing infrastructure, whereas lack of investment prohibits its reinforcement. Therefore, the efficient utilisation of the existing network is not only suggested for economy, but also imposed by need. Consequently, the realisation of government targets for renewable energy will depend, in part, on the ability of developers and Distribution Network Operators (DNOs) to maximise generator capacities connected to the network whilst minimising negative impacts.

One means of ensuring maximum capacity with minimal voltage impact is through the use of intelligent power factor and voltage control of generators and other network components. Previously published work demonstrated the benefits in terms of the minimisation of voltage variations and violations as well as the ability of larger generators to connect to the network. While the capacity benefit could be easily quantified for individual dispersed generators, it was more difficult to explore the benefit of widespread usage.

To achieve this it was necessary to draw on earlier work that used Optimal Power Flow (OPF) techniques to evaluate the network capacity available for connecting dispersed generators. The capacity evaluation technique was extended such that it could incorporate the intelligent generator control algorithms and in doing so could find optimal levels of connections. The results of a case study indicate that intelligent power factor and voltage control of generators increases significantly the connecting capacity of existing networks.

GENERATOR CONTROL: AVR VERSUS PFC

To date, Distribution Network Operators have generally been reluctant to allow any operation by independent generators which could potentially disrupt the passive role of the distribution network to supply demand. Specifically, Distributed Generators (DGs) are not permitted to perform Automatic Voltage Regulation (AVR), an inherent feature of synchronous generators to regulate the terminal bus voltage by adjusting their reactive power output, as it may destabilise the automatic Load Tap Changers (LTCs) of distribution transformers. A further issue is that where a small generator with AVR control is connected to a utility bus that suffers from voltage drops, it has to inject great amounts of reactive power in order to raise the bus voltage. This may result in high field currents and overheat the generator, triggering the protection and disconnecting the generator from the network. Accordingly, in most DG applications the generators do not have AVR control.

DGs usually operate in Power Factor Control (PFC) mode. They produce proportional amounts of active and reactive power in order to maintain constant Power Factor (PF) at all times. PFC is less disruptive for LTCs and results in much lower field currents than AVR under voltage drops, therefore reduces thermal stresses on the generator [1].

TACKLING VOLTAGE RISE FROM NEW CAPACITY

Unfortunately, PFC has an adverse effect on the generator's terminal bus voltage. The voltage drop ΔV along a radial feeder is approximated by the equation:

$$\Delta V = R \cdot P + X \cdot Q \qquad (1)$$

where $R+jX$ is the line impedance and P, Q the active and reactive power produced by the DG. When P increases V rises. In PFC mode P/Q is maintained constant, so when P increases Q follows and V increases even further! Conversely, when P decreases, Q decreases as well, leading to further voltage drop. Masters [2] notes that voltage rise as one of the major impacts of, and constraints on, the connection of new DGs on the network.

In equation (1), if Q was allowed to compensate for the feeder voltage rise or drop created by P by adjusting in the opposite direction (with P), then V could be maintained within limits allowing greater active power export. For voltage rise, this would be achieved by defining a leading power factor at which the generator is to be controlled. Power factor settings could be specified on a time-of-day basis, wherein DG operates at lagging power factor to export reactive power during high demand periods whilst importing during low demand. While this appears to be a relatively simple approach, it would require analysis to ensure that voltage is maintained appropriately under all normal operation cases and may require a degree of central coordination.

An alternative to these techniques would be that the generator itself controls reactive power in an 'intelligent' and 'network friendly' manner.

INTELLIGENT GENERATOR CONTROL

Kiprakis and Wallace [3], [4] proposed a voltage control method for DGs which assumed a more flexible directive from DNOs in terms of the voltage control by DGs. The target was to develop a voltage control method capable of keeping DGs online during light and/or heavy loading conditions by combining the advantages of AVR and PFC. The method was termed Automatic Voltage / Power Factor Control (AVPFC) and it relaxes the PFC when voltage approaches limits defined

by statute or by the DNO (with reference to accepted engineering practice). In normal operation and within defined minimum (V_{min}^{PFC}) and maximum (V_{max}^{PFC}) threshold voltages, the DG operates in PFC mode at a defined power factor (PF_{PFC}). When voltage reaches these limits, which lie within the defined voltage limits (V_{min}, V_{max}) the PFC is deactivated and the DG operates in AVR mode, producing or absorbing reactive power to support voltage. The generator produces additional reactive power to maintain a low voltage during high demand periods and absorbs it to contain a high voltage during low demand periods. The DG must be restricted to its over and under-excitation limits as defined by the minimum and maximum operating power factors PF_{min} and PF_{max}, respectively. Once the generator reaches its excitation limits the voltage will no longer be controlled and may continue to move towards the statutory limits before the voltage protection equipment operates to disconnect the DG. Figure 1 presents the AVPFC operational scheme with the generator operating on the thick, dashed line.
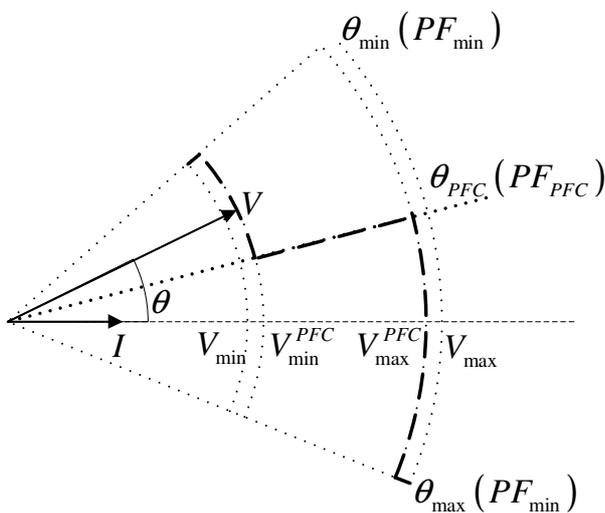

Figure 1 Hybrid AVPFC voltage control.

In extensive simulations, the AVPFC algorithm was found to extend the period of operation for an individual DG in a weak network and increased revenue from energy export. A further benefit was that the method allowed a larger generator to connect to the network without voltage violations during low demand periods [4]. Identifying the benefit in terms of enhancing DG connection was relatively straightforward for the single generator. In examining the benefit of applying the technique on a widespread basis with two or more generators it was found that the interdependency of voltage in the network made manual comparisons rather difficult and time consuming. A more sophisticated approach was sought.

CAPACITY ALLOCATION

It was recognised that attempts to determine the additional generator capacity added to the network through the use of intelligent control was similar in aim to other work published by Harrison and Wallace [5], [6]. Their aim was to develop a means of determining available network capacity for DG

connection. Using proprietary Optimal Power Flow (OPF) software and modelling DG as negative loads, the 'reverse-loadability' technique found the maximum capacity of DG that could be connected at any given set of locations in the network subject to network voltage and thermal constraints.

The approach was extended significantly by Vovos *et al.* [7] which incorporated fault level as a constraint in the OPF via a stepwise interative approach. A bespoke implementation of an OPF was required for this and presented the opportunity to explicitly model power factor controlled DG. Reference [8] describes the formulation of OPF, but a brief outline of the method implemented in [7] is given below.

New Generation Capacity

New generators are simulated as generators with quadratic cost functions with negative coefficients. These generators are connected to predetermined locations in the network, the "Capacity Expansion Locations" (CELs), with the output of generators simulating the allocated capacity at the CEL. Since in most DG applications the generators perform PFC we can simplify our analysis by assuming that CELs have constant lagging power factors set at 0.9. This assumption also holds for most DG installations that interface to the network through inverters [9].

Cost Model

The cost model assumes that the negative cost (benefit) C_g from new generation capacity is connected only to the size of new generators P_g:

$$C_g\left(P_g\right) = a \cdot P_g^2 + b \cdot P_g + c \qquad (2)$$

w.r.t. a,b,c < 0 and P_g > 0, where C_g is the operational cost of generator g at output level P_g. Different sets of coefficients between cost functions declare preferences for the allocation of new capacity between CELs. If the voltage control scheme enforced by the DNO affects the allocated size of DGs at the CELs, then its impact will be reflected in the OPF objective function. Therefore, the cost model is capable of encapsulating the effects of different voltage control schemes.

Tie Lines

Energy transfers from/to external networks are also simulated as generators with quadratic cost functions. We will refer to them as Export/Import Points (E/IPs). The coefficients of the cost functions are negative for exports and positive for imports. The outputs of the generators are negative when they represent exports and positive when they represent imports.

Existing Capacity and Loads

Existing generation capacity is simulated as generators with constant active power output, equal to their maximum capacity, and given reactive power injection capabilities. Loads are simulated as sinks of constant active and reactive power.

INTELLIGENT VOLTAGE CONTROL IN OPF

Generally, DG capacity is simulated with the real power output P^g of virtual generators placed at the CELs. In order to examine the impact an alternative voltage control scheme has

on network capacity using the OPF, we have to simulate the behavior of DGs implementing those schemes during steady-state operation.

The main difference in the OPF formulation between DGs operated under the current voltage control scheme ('PFC-Gens') and the hybrid scheme (hereafter termed 'Intelli-Gens') is that the otherwise constant PF is allowed to vary (within the DG operating limits) when voltage drops or rises beyond a critical value. Since we focus on capacity planning it is logical to expect that new capacity will only raise voltage levels. Thus, in order to simplify our analysis we will assume that the PF constraint is relaxed only when the generator's voltage V_G rises to a critical value $V_{threshold}$. In addition, in order to consider leading and lagging PFs we will constrain the angle $\theta_G = sign(PF) \cdot \cos^{-1}(PF)$ instead of the PF directly, where sign(PF) is positive for lagging and negative for leading PF.

Finally, the minimum (PF_{min}) and maximum (PF_{max}) operating PFs are roughly the same for various sizes of DGs. Therefore, we can presume that $PF_{min}, \theta_{min}, PF_{max}, \theta_{max}$ are common for all new DGs. Furthermore, PF_{max} is usually the rated PF, so it is considered here as the target PF_{PFC} of PFC. Both these assumptions can be described in the OPF formulation by the following constraints for the virtual generators at the CELs:

$$PF_{min} < PF_G < PF_{max} \Rightarrow \theta_{min} < \theta_G < \theta_{max}$$
$$\text{and} \quad PF_{max} = PF_{PFC} \Rightarrow \theta_{max} = \theta_{PFC} \tag{3}$$

The voltage control strategy of Intelli-Gens is described by the curve in the power factor (θ_G) versus voltage (V_G) graph as Figure 2 shows.
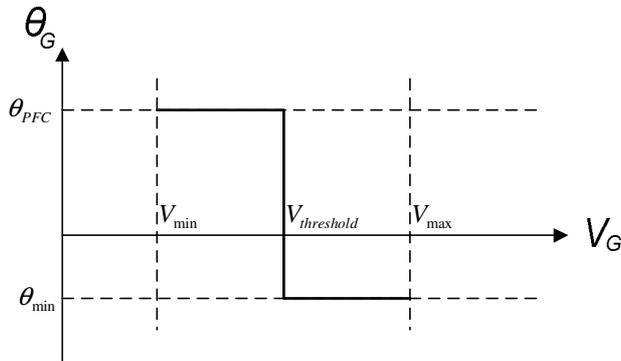

Figure 2. Voltage control strategy of Intelli-Gens.

Equation (4) describes this control strategy mathematically:

$$\theta_G = \theta_{PFC} \qquad \text{when} \quad V_{min} \leq V_G < V_{threshold}$$
$$\theta_{PFC} < \theta_G \leq \theta_{min} \quad \text{when} \quad V_G = V_{threshold} \tag{4}$$

In order to avoid the optimisation burden that discrete transitions create we approximate (4) with the equality constraint below:

$$\theta_G = \theta_{eq.} \Rightarrow \tan^{-1}(Q^G / P^G) = A + K \cdot \tan^{-1}(B \cdot V_G + C) \tag{5}$$

where $K = K_{steep} \dfrac{\theta_{PFC} - \theta_{min}}{\pi}$, and

$$A = \theta_{min} + K \frac{\tan^{-1}[S_1 + S_2]}{(V_{max} - V_{threshold}) \cdot \eta\mu_{threshold}^{min} \cdot \eta\mu_{max}^{min}}$$

where $S_1 = (V_{max} - V_{min}) \cdot \eta\mu_{threshold}^{min} \cdot \sigma\upsilon\nu_{max}^{min}$

where $S_2 = (V_{min} - V_{threshold}) \cdot \eta\mu_{max}^{min} \cdot \sigma\upsilon\nu_{threshold}^{min}$

where $\eta\mu_y^x = \sin[(\theta_x - \theta_y)/K]$, $\sigma\upsilon\nu_y^x = \cos[(\theta_x - \theta_y)/K]$

$$B = \frac{\tan[(\theta_{threshold} - A)/K] - \tan[(\theta_{max} - A)/K]}{V_{threshold} - V_{max}}$$

and $C = \tan[(\theta_{max} - A)/K] - B \cdot V_{max}$.

K_{steep} is a real number marginally over 1, which defines the steepness of $\tan^{-1}$. The higher the value, the smoother the transition from θ_{PFC} to θ_{min}. A value of 1.01 for K_{steep} produces a quite smooth function without significant loss in precision. This approximation creates a 'smooth' transition around $V_{threshold}$ for θ_G with respect to V_G (Figure 3).
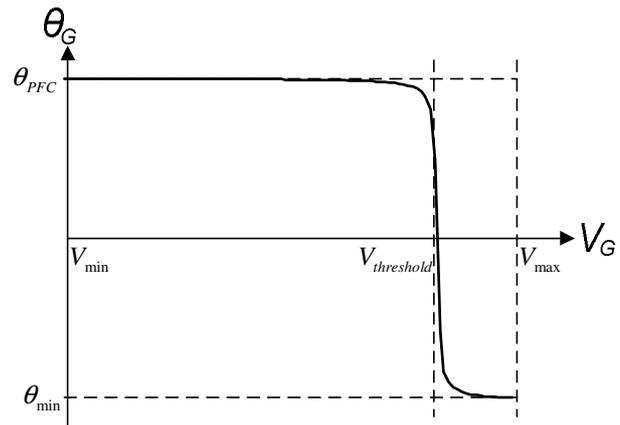

Figure 3. Smoothing of control strategy transition for Intelli-Gens.

CASE STUDY

Network Topology

The 12-bus 14-line network presented in Figure 4 has 3 CELs at buses 1, 10 and 11. It also has an E/IP to an external network at bus 12. A 15 MW generator is installed on bus 5, capable of providing up to 10 MVAr of reactive power. The network has a common rated bus voltage level at 33 kV, except for the CEL buses which have a rated voltage of 11 kV and the E/IP bus at 132 kV. The CEL buses connect to the network through 30 MVA transformers with fixed taps. The E/IP bus connects through a 90 MVA transformer with automatic tap changer, which regulates the voltage within a ±2% range of the rated voltage at the low voltage side with a ±10% tap range around the nominal tap ratio. The electric characteristics of transformers and lines are presented in the table next to the network topology in Figure 4. We assume that loads consume

constant complex power on buses 1, 3, 5, 6, 8, 10 and 11. Their size is depicted on the same figure.
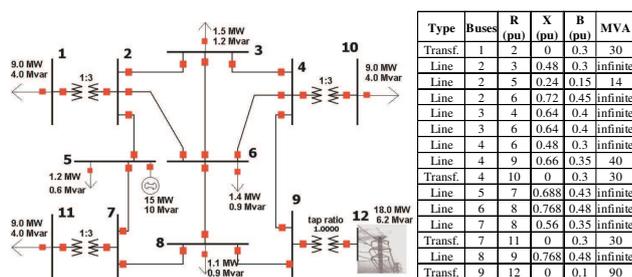

Type	Buses		R (pu)	X (pu)	B (pu)	MVA
Transf.	1	2	0		0.3	30
Line	2	3	0.48		0.3	infinite
Line	2	5	0.24	0.15		14
Line	2	6	0.72		0.45	infinite
Line	3	4	0.64	0.4		infinite
Line	3	6	0.64	0.4		infinite
Line	4	6	0.48		0.3	infinite
Line	4	9	0.66	0.35		40
Transf.	4	10	0		0.3	30
Line	5	7	0.688	0.43		infinite
Line	6	8	0.768	0.48		infinite
Line	7	8	0.56	0.35		infinite
Transf.	7	11	0		0.3	30
Line	8	9	0.768	0.48		infinite
Transf.	9	12	0		0.1	90

Figure 4. 12-bus 14-line test case and transformer/line characteristics

Constraints

Line 2-5 is constrained by a thermal limit of 14 MVA, 4-9 by a thermal limit of 40 MVA, while all other lines are considered to be unconstrained. We assume that the E/IP can exchange up to 100 MW with the external network without affecting its secure operation. The external network is also capable of providing/consuming up to 60 MVAr of reactive power to the local network. Finally, statutory regulations limit bus voltage fluctuations to ±10% around the nominal values. The CELs at buses 1, 10 and 11 will accommodate PFC-Gens and Intelli-Gens in turn.

Voltage Control Properties

We assume that the voltage control strategy of Intelli-Gens has $V_{threshold}$ = 1.05 p.u. for the relaxation of the PFC from a PF of 0.9 lagging. When the generator's voltage reaches $V_{threshold}$ they are permitted to operate at any PF between 0.9 lagging and 0.9 leading. We will examine the impact of each control strategy on network capacity assuming that there is no preference for the allocation of new generation capacity at any specific CEL.

RESULTS

The initial capacity allocation from OPF is presented in Table 1. PFC results in the lowest total new capacity and exports.

TABLE 1 - OPF capacity allocation with PFC and Intelli-Gens

	PFC	Intelli-Gens	Change
CEL 1	9.2 MVA PF=+0.90	28.3 MVA PF= - 0.96	19.1 MVA
CEL 10	25.9 MVA PF=+0.90	24.8 MVA PF= +0.99	-1.1 MVA
CEL 11	15.3 MVA PF=+0.90	33.0 MVA PF= - 0.96	17.7 MVA
Total MVA	50.4 MVA	86.1 MVA	35.7 MVA
E/IP	-25.2 MW	-38.1 MW	12.9 MW
Losses	4.0 MW	29.2 MW	25.2 MW
Obj.Fun.	1411.5	2424.2	1012.7

Obviously, the broader the voltage operating region of the generators the broader the solution space for the OPF. Consequently, the OPF objective function has a value which increases in each case that we relax the PF control further: in turn PFC-Gens and Intelli-Gens. However, the impressive total

capacity achieved from the Intelli-Gens comes at a cost: high losses. This is due to the fact that most of the reactive power consumed by Intelli-Gens during their attempt to maintain low terminal voltage, is provided from the distant E/IP at bus 12. Reactive power traveling long distances through a network raises losses.

CONCLUSION

The main conclusion of this paper is that the relaxation of DNOs' strict PFC policies, specifically, through widespread application of intelligent automatic voltage/power factor control schemes allow the connecting capacity of the existing network to be better exploited. Further work is required to compare the potential benefits of intelligent local control with those that accrue from a more centralised, active approach to voltage control within the distribution network.

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